DRAFT

Big Stone II Delivery Service Study

Performed by

for the

MAPP Design Review Subcommittee (DRS)

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V Disclaimer

The information contained in this study report is in draft form and may be subject to revision, verification, and/or additional evaluation. The person receiving such information from Missouri River Energy Services, Otter Tail Power Company, or the Midwest ISO may use this information only with the full knowledge that this draft information cannot be relied upon as accurate.

VI Gratitude

The Big Stone II project, MRES and OTP in particular, would like to thank the regional utilities and MISO for helping to provide valuable comments to results and input into the development of the powerflow models.

VII Abbreviations and Definitions

Abbreviation	Full word
AC	Alternating Current
ALTW	Alliant Energy – West system
BEPC	Basin Electric Power Cooperative
BRIGO	Buffalo Ridge Incremental Generation Outlet study. A study performed by Xcel Energy to determine modest transmission system additions in SW MN to accommodate the next increment of generation out of the Buffalo Ridge following the "825 MW" facilities.
BSP II	Big Stone II
CON	Certificate of Need
CMMPA	Central Minnesota Municipal Power Agency
CT	Combustion Turbine
DC	Direct Current
DF	Distribution Factor
DPC	Dairyland Power Cooperative
DRS	Design Review Subcommittee (MAPP)
EM Rating	Emergency Rating
FEIS	Federal Environmental Impact Statement
EHV	Extra High Voltage
GRE	Great River Energy
HCPD	Heartland Consumers Power District

IS	Integrated System – Western Area Power Administration Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District Integrated transmission System.
LES	Lincoln Electric Systems
MAPP	Mid-continent Area Power Pool
MDU	Montana Dakota Utilities
MEC	MidAmerican Energy Company
MH	Manitoba Hydro
MISO	Midwest Independent Transmission System Operator
MN	Minnesota
MP	Minnesota Power
MPC	Minnkota Power Cooperative
MPW	Muscatine Power and Water
MRES	Missouri River Energy Services
MTEP	MISO Transmission Expansion Plan
MWSI	Minnesota – Wisconsin Stability Interface
NDEX	North Dakota Export Interface
NERC	North American Electric Reliability Council
NMORWG	Northern MAPP Operating and Review Working Group
NPPD	Nebraska Public Power District
OASIS	Open Access Same Time Information System
OPPD	Omaha Public Power District

OTDF	Outage Transfer Distribution Factor
OTP	Otter Tail Power Company
Partial Path Reservations	In this report, this term is used for transmission service only requested on the IS OASIS, but with a sink in the MISO system, and for transmission service requested on both the IS and MISO OASIS with different queue times. More specifically, this service is queued ahead of Big Stone II on the IS OASIS, and after Big Stone II on the MISO OASIS. Throughout the report there are both MISO and non-MISO listing of constraints for scenarios that include the IS partial path requests. The MISO constraints are only listed for the reader's information. Only the WAPA/IS constraints are constraints that the Big Stone II project will have to mitigate. The scenarios studied with the partial path requests were modeled from ultimate source to ultimate sink.
PI-BY	Prairie Island – Byron 345 kV line (interface)
PSS/E	Power System Simulator for Engineers. Software tool developed by Siemens Power Technologies Incorporated (PTI) to simulate power system performance.
PTDF	Power Transfer Distribution Factor
PVS	Pleasant Valley Station
Rate A	Refers to the rate A field in PSS/E models for lines and transformers. Often also referred to as normal or continuous rating.
SAF	Significantly Affected Facility. Any facility that is outside of the applicable criteria during system intact or contingency conditions as identified during the steady state contingency analysis.
SD	South Dakota
SMMPA	Southern Minnesota Municipal Power Agency
SPC	Saskatchewan Power Corporation

St. Boni	GRE St.Bonifacius generation/substation
SVC	Static VAR compensator
Transmission Alternative 1	Big Stone – Johnson Jct. – Morris 230 kV, and Big Stone – Canby – Granite Falls 230 kV
Transmission Alternative 2	Big Stone – Willmar 230 kV, and Big Stone – Canby – Granite Falls 230 kV
TSR	Transmission Service Request
URGE	Maximum gross MW power output of a generator
WAPA	Western Area Power Administration
XCAP	MAPP Transmission Capacity Report

VIII How to Read the Tables

VIII.I Thermal Constraint Tables

The following explains the tables summarizing the thermal constraints observed in the main body of this report:

Column Name	**Explanation**
Constraint Element	Line or transformer flagged as constraint by bus # and name
Contingency example	One example of contingency seen that aggravates the constraint identified.
Owner	Owner of the constraint element
Rate A	PSS/E Rate A / Normal Rating
EM Rate	Emergency rating of constraint element
%DF high	The highest distribution factor observed on the constraint element in %
High MVA Loading	Highest MVA loading observed in simulation. W/O IS refers to highest loading seen in scenarios without the IS partial path requests. W/ IS refers to highest loading seen in scenarios with the IS partial path requests.
Note	Refers to special notes on the listing. Explanation can be found as a footnote under the table.

VIII.II Steady State Voltage Constraint Tables

Column Name	Explanation
Bus #	Bus number as it appears in the powerflow model
Bus Name	Bus name – by English name if known, otherwise by name in powerflow model
kV	Nominal kV of the bus
System Intact Voltage w/o BSP II	Self-explanatory with voltage given in %
System Intact Voltage w/ BSP II	Self-explanatory with voltage given in %
Worst Contingency	Contingency causing the lowest voltage
Post cont. w/o BSP II [%]	Post contingent voltage without Big Stone II in %
Post cont. w/ BSP II [%]	Post contingent voltage with Big Stone II in %
Worst change in voltage [%]	Worst difference in voltage observed on the bus between the case w/o Big Stone II, and the case with Big Stone II.
Comment	Contains general comments of possible causes or mitigation

1.0 Executive Summary

Big Stone II is a proposed 600 MW new coal fired power plant at the site of the existing Big Stone generator near Big Stone City in northeastern South Dakota. The plant would be in the MISO footprint, as a part of the OTP balancing area. It is scheduled to come online in the spring of 2011. The current participants in the plant are:

- Central Minnesota Municipal Power Agency (CMMPA), Blue Earth, MN – 30 MW
- Great River Energy (GRE), Elk River, MN – 116 MW
- Heartland Consumers Power District (HCPD), Madison, SD – 25 MW
- Missouri River Energy Services (MRES), Sioux Falls, SD – 150 MW, where 40 MW will go to Hutchinson Utility Commission (HUC), Hutchinson, MN
- Montana Dakota Utilities (MDU), Bismarck, ND – 116 MW
- Otter Tail Power Company (OTP), Fergus Falls, MN – 116 MW
- Southern Minnesota Municipal Power Agency (SMMPA), Rochester, MN – 47 MW

This report addresses part of the steady state delivery studies required to identify constraints that would have to be mitigated for purposes of both MISO and WAPA/IS transmission service requests to be granted. HCPD and MRES have placed transmission service requests on the WAPA OASIS, to serve load on WAPA/IS system. This study addresses what are termed Phases 1-4:

- Phase 1: 2009 Summer Peak (near term summer peak) conditions with confirmed reservations only
- Phase 2: 2009 Summer Peak (near term summer peak) conditions with confirmed and prior queued study mode reservations
- Phase 3: 2014 Summer Peak (out year summer peak) conditions with confirmed and prior queued study mode reservations
- Phase 4: 2011 Winter Peak conditions with confirmed and prior queued study mode reservations

Phases 1-4 are all performed to comply with MAPP DRS, MISO and local Transmission Owner requirements as applicable. Some scenarios in these phases though are unique for the non-MISO MAPP footprint in that partial path reservations from the Integrated System to MISO are modeled in the base case assumptions.

In addition two more phases will be completed at a later date:

- Phase 5: Summer off-peak studies with high stressed interfaces
- Phase 6: High level facility study

Phase 5 is something typically required by the MAPP DRS, and will be submitted only to the DRS prior to the request for overall approval of the Big Stone II studies. Phase 6 will cover aspects of all the preceding scenarios, as well as any further MAPP and MISO requirements.

A separate report addresses interconnection concerns including local and regional stability, fault analysis, and local thermal analysis. (Reference MISO Generation Interconnection Study report for project G392).

Throughout the study, input was solicited from local transmission owners and from MISO. Results were brought before the Northern MAPP (NM) and Missouri Basin (MB) Sub-regional Planning Groups. Big Stone II participants also made extensive efforts to work with WAPA regarding any potential impacts on the Integrated System. Big Stone II participants worked directed with WAPA and have held multiple meetings to ensure modeling assumptions utilized in these studies were acceptable. The input from the ad-hoc group included review of models prior to the simulations being performed, and individual verification with local transmission owners on possible constraints observed.

For reasons of the regulatory processes for approval of needed transmission lines within the state of MN, this report looked at two different transmission options:

- Alternative 1: 230 kV line from Big Stone – Johnson Jct. – Morris, and 230 kV line from Big Stone – Canby – Granite Falls

- Alternative 2: 230 kV line from Big Stone – Willmar, and 230 kV line from Big Stone – Canby – Granite Falls

The project has stated within their MN CON application that Alternative 1, is the preferred option.

Constraints were found for each phase of this study. Some constraints can likely be addressed via operating guides; others must be addressed through physical upgrades or additions to the system. Some of the constraints are electrically local to the plant site, and some appear to be more driven by the chosen sinks for the various phases. Both thermal and voltage issues are observed. Some constraints appear to be related to load serving issues. Discussing issues with local transmission owners, some of the areas that are identified as problems herein, are indeed areas currently under investigation for resolution. Examples of such are voltage issues seen in the area served by the Fort Ridgley 115/69 kV transformer (e.g. New Ulm, MN), and the greater Alexandria, MN area. A study addressing New Ulm area load serving is anticipated to be available in early 2007. MRES has plans for system upgrades mainly for voltage security in the Alexandria area, which could have far-reaching benefits with respect to the voltage issues observed in this study. Some constraints are clearly driven by the new plant itself. Examples would be the Morris 230/115 kV transformer, and the Grant County – Morris 115 kV line.

For a detailed listing of the thermal and voltage issues identified for each alternative, refer to section 8 “Conclusions”.

This report focuses on flagging any potential constraints. More study work will be completed in Phase 6 in particular to address the impacts from Tables 1-1 through 1-4. Phase 6 is also considering the effect of projects such as those announced by the CapX 2020 group, and other projects that have matured since the Big Stone II delivery studies were started. Verification of ratings and limitations of various facilities will also be an ongoing task, as well as determining how operating guides might help resolve some constraints.

2.0 Introduction

Seven entities, namely Central Minnesota Municipal Power Agency (CMMPA), Great River Energy (GRE), Heartland Consumers Power District (HCPD), Missouri River Energy Services (MRES) of which part will go to Hutchinson Utilities Commission (HUC), Montana-Dakota Utilities (MDU), Otter Tail Power Company (OTP) and Southern Minnesota Municipal Power Agency (SMMPA), are currently investigating the possibility of adding a 600 MW generator at the existing Big Stone site in northeastern South Dakota. The location of the Big Stone site is shown below in Figure 2-1. The current transmission system for outlet of the existing unit consists of two 230 kV lines and two 115 kV lines to transfer power onto the transmission system.

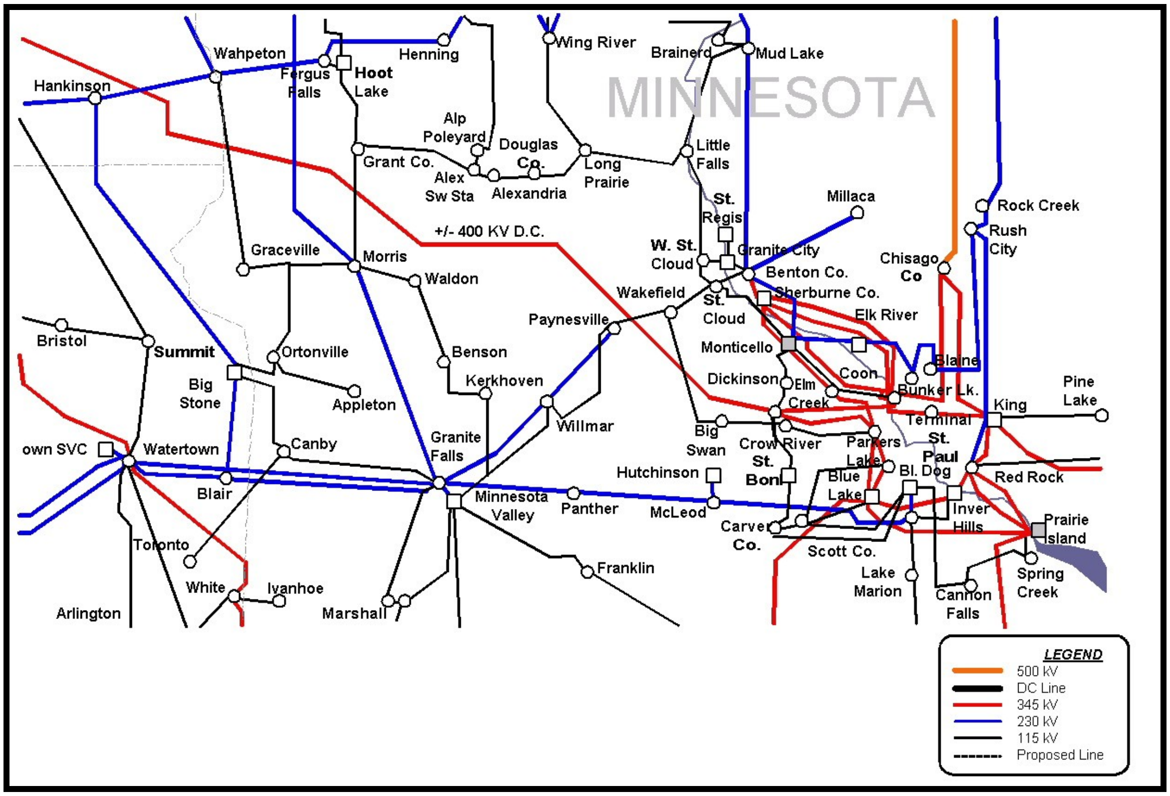


Figure 2-1 Big Stone's Location within Northeastern South Dakota

The transmission studies associated with this plant are being completed as required by the Midwest ISO, IS tariff, and MAPP policies and procedures. This document addresses the bulk of the Delivery Service Study (Phases 1 through 4 out of a total of 6 as described later).

2.1 Background of Project Through the Study Process

The Big Stone II project submitted a generation interconnection request to MISO in February of 2004. MISO is processing this request as project G392. A brief overview of the interconnection study is included in the following sections. More specific details of the interconnection study can be found on MISO's generator interconnection queue under queue number 38020-01.

To accompany this new generator, the Big Stone II project participants have also submitted multiple transmission service requests for delivering the output of this new plant to their respective loads. A total of 101 transmission service requests were received by MISO on April 1, 2004. MISO has grouped these 101 transmission service requests into MISO project number A190. A portion of this project is currently proposed to be owned by MRES and HCPD. Since these entities are transmission customers of WAPA, two transmission service requests were also submitted to the WAPA OASIS for Big Stone II in order to request transmission service on the IS. Great efforts have been undertaken to coordinate the MISO and WAPA queues in order to meet the requirements of both transmission providers with one study.

After the submittal of these initial requests, discussion among the Big Stone II participants broadened to include potentially new owners. In addition, other participating entities in the project had a desire to add to their flexibility in taking delivery from the new generator. Therefore, new transmission service requests were made by Missouri River Energy Services on September 14, 2004 and by Montana-Dakota Utilities on October 17, 2004. These new transmission service requests were submitted to MISO, which resulted in the new MRES requests being assigned a project number of A217 and the new MDU requests being assigned a project number of A219.

The Big Stone II participants include both MISO and non-MISO members. Consequently, some of the Big Stone II participants submitted only transmission service requests with MISO, while others submitted request for transmission service from both MISO and WAPA/IS. One comprehensive study has been completed to address the requirements of both the MAPP DRS and MISO. The study work has hence been coordinated with MISO and WAPA/IS as well as other regional transmission owners. Presentations of results have been given to the Northern MAPP and Missouri Basin Sub-regional Planning Groups.

2.2 Study Scope

The Big Stone II Delivery Study is a comprehensive study that has investigated a variety of conditions for both summer and winter conditions. Steady state contingency analysis and constrained interface analysis has been completed to determine any Significantly

Affected Facilities (SAF) and any impacts to known flowgates in the MAPP and MISO regions.

The scope of this Delivery Service Study is to perform an assessment of the delivery adequacy (steady state thermal and voltage constraints) of the system for the TSR's associated with Big Stone II. In order to determine whether a facility qualifies as a SAF, the appropriate regional criteria were applied to screen for thermal, steady state voltage, and flowgate concerns. This analysis included both MISO and MAPP facilities.

A comprehensive list of SAF identified during this study are listed in section 8.0**.** This report does not include summer off-peak analysis results, which will be published in a separate document, or as an amended version of this report.

The study presented in this report was divided into four phases, plus an additional two phases that will be presented at later dates. In summary, the various phases are as follows:

- Phase 1: 2009 Summer Peak (near term summer peak) conditions with confirmed reservations only
- Phase 2: 2009 Summer Peak (near term summer peak) conditions with confirmed and prior queued study mode reservations
- Phase 3: 2014 Summer Peak (out year summer peak) conditions with confirmed and prior queued study mode reservations
- Phase 4: 2011 Winter Peak conditions with confirmed and prior queued study mode reservations
- Phase 5: High stressed summer off-peak conditions
- Phase 6: Impact of planned and proposed system upgrades from CapX, MTEP, BSP II and other projects identified for Phases 1-5

All phases include additional sub-scenarios looking at the two different transmission alternatives, and with and without a set of IS partial path reservations. More details on each phase of the study can be found throughout the report.

3.0 Transmission Alternatives

The interconnection study for the Big Stone II project included steady state power flow analysis, transient stability analysis, and short circuit analysis. The interconnection study has been performed for two different transmission alternatives and impacts on the existing transmission system for each alternative have been identified. Both of these alternatives have one common aspect, which is the addition of a new 230 kV line from Big Stone to Canby with an upgrade of the existing 115 kV line from Canby to Granite Falls. The two transmission alternatives studied for the Big Stone II interconnection request are shown below in Table 3-1.

1. New 230 kV line from Big Stone to Ortonville with upgrade of Ortonville to Johnson Junction to Morris 115 kV line to 230 kV with new 230 kV line from Big Stone to Canby and an upgrade of the Canby to Granite Falls 115 kV line to 230 kV.
2. New 230 kV line from Big Stone to Willmar with new 230 kV line from Big Stone to Canby and an upgrade of the Canby to Granite Falls 115 kV line to 230 kV.

Table 3-1 Transmission Alternatives for Big Stone II Interconnection Study

Geographic maps illustrating the two different alternatives are included as Figures 3-1 and 3-2 on the following pages.

Two transmission alternatives are currently proceeding through the regulatory process in Minnesota. The project has stated that it would prefer to get permits for alternative 1. Ultimately only one alternative would be built.

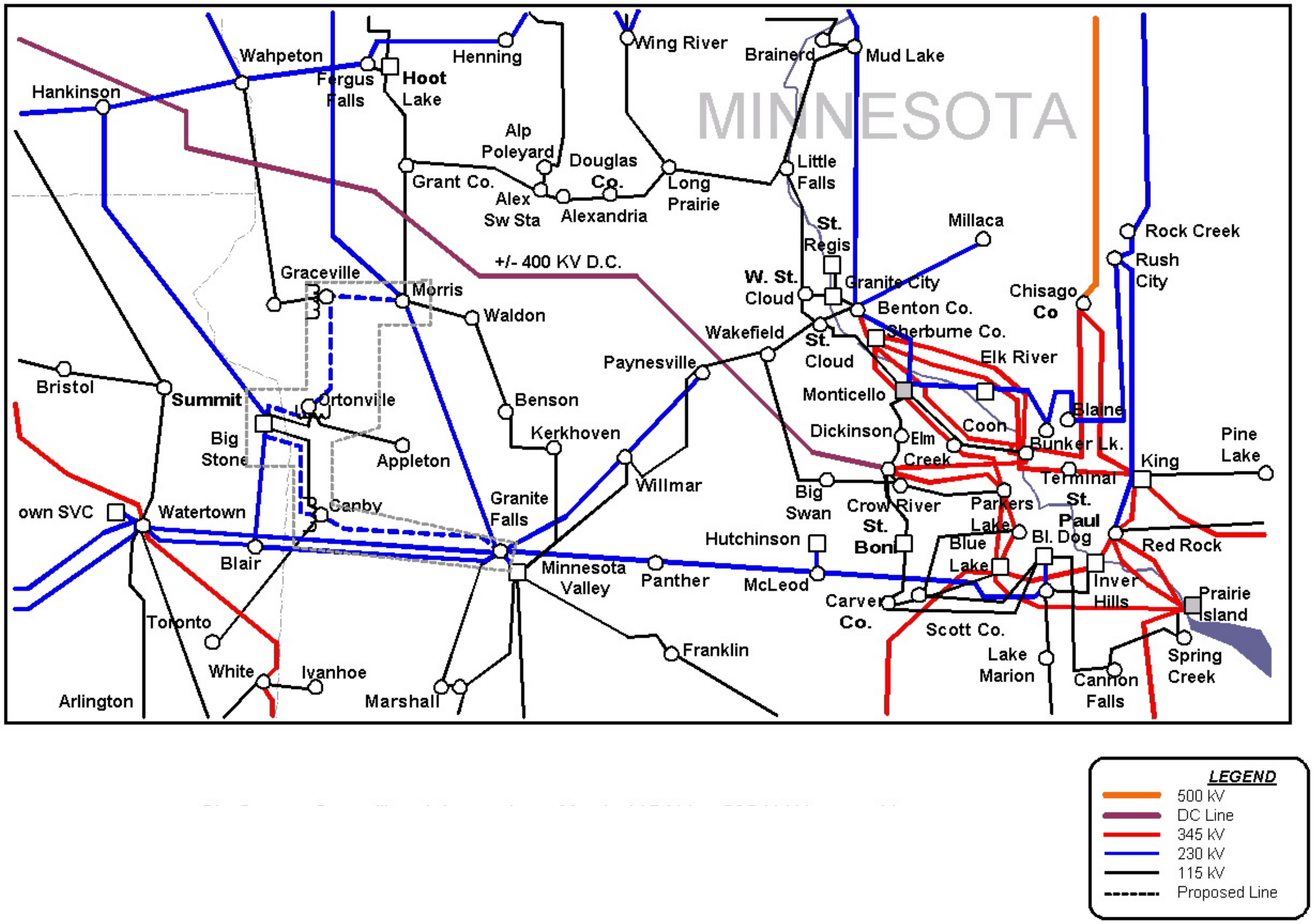


Figure 3-1 Geographic Map of Alternative 1

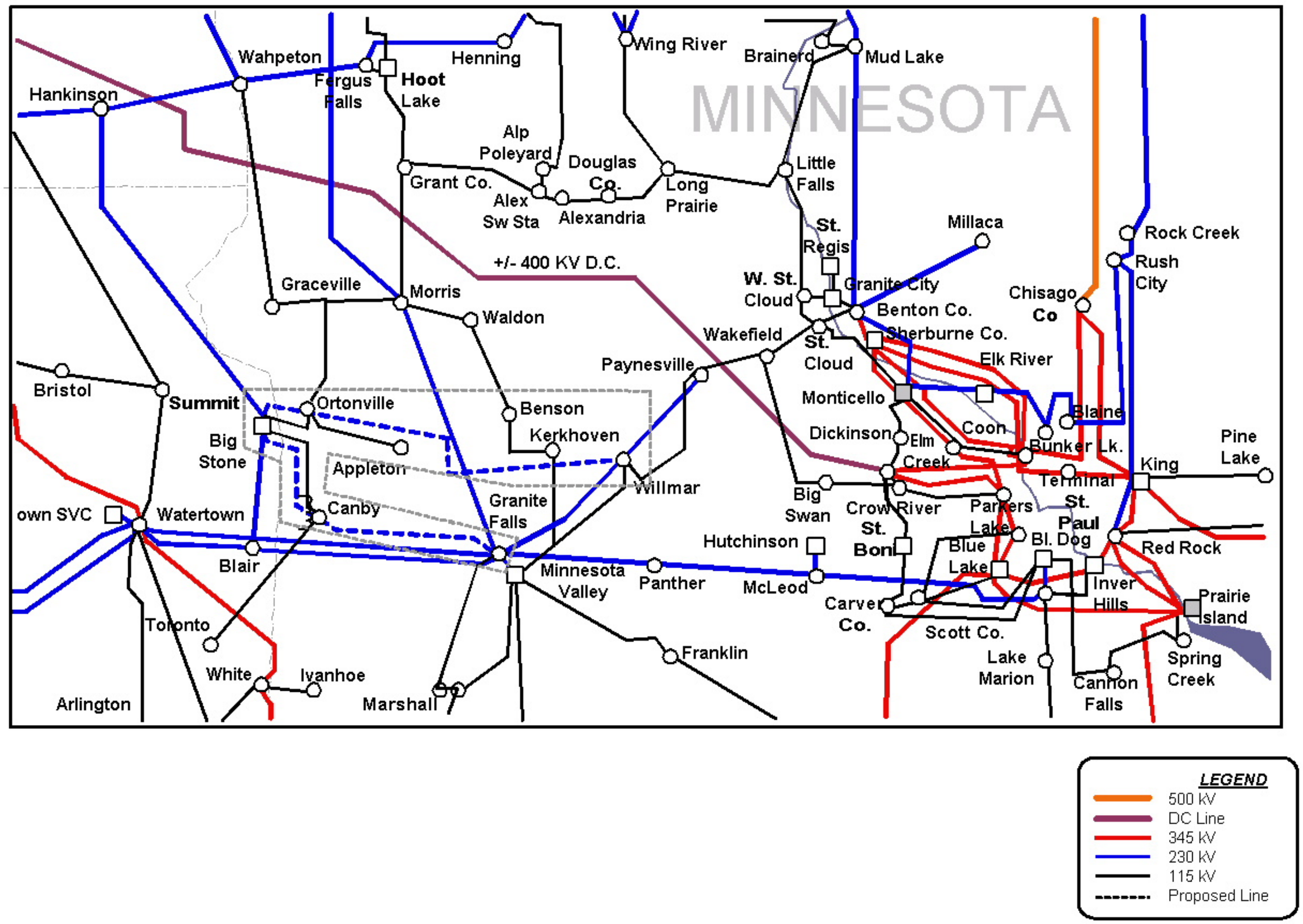


Figure 3-2 Geographic Map of Alternative 2

Steady state analysis for the interconnection study utilized 2007 summer peak and 2007 summer off-peak models. These steady state models were derived from the 2002 series MAPP models and have been used in several previous studies, including the "Group 1" and "Group 2" MISO/WAPA coordinated interconnection studies for the numerous generation requests in the Buffalo Ridge area. These group studies analyzed the feasibility of connecting a large amount of wind generation within the Buffalo Ridge area of southwest Minnesota, northwestern Iowa, and eastern South Dakota.

Loading violations encountered during the Big Stone II interconnection study are shown below in Table 3-2. The quantities displayed within Table 3-2 represent the percent loading on each facility based on its normal continuous rating. Any quantities highlighted in yellow represent facility loadings that did not exceed emergency ratings while those quantities highlighted in red represent loadings that did exceed emergency ratings and will require mitigation.

	Summer Peak		Summer Off-peak	
Overloaded Facility	**Alt #1**	**Alt #2**	**Alt #1**	**Alt #2**
Big Stone 230/115/13.8 kV Transformer	119.2%	111.8%	103.5%	
Morris 230/115 kV Transformer	177.0%		155.2%	
Ortonville - Johnson Jct. 115 kV Line		141.7%		131.1%
Big Stone - Browns Valley 230 kV Line	128.7%	114.1%		
Big Stone - Highway 12 115 kV Line	112.6%			
Highway 12 - Ortonville 115 kV Line	106.9%			
Johnson Jct. - Morris 115 kV Line		118.2%		

Table 3-2 Overloaded Elements (Given in % overload of Rate A) for Big Stone II Interconnection Study

Voltage violations identified during contingency analysis of the Big Stone II interconnection study indicated that a decrease in voltage is caused by implementing transmission alternative 2 with the Big Stone II plant. A summary of the post-contingent voltage levels is given below in Table 3-3 in per unit voltage. Those post-contingent voltage levels are below the applicable voltage criteria set by transmission owners in this region and will require mitigation.

	Summer Peak		Summer Off-peak	
Voltage Violation	**Alt #1**	**Alt #2**	**Alt #1**	**Alt #2**
Willmar 115 kV Bus		0.90		0.88
Willmar 230 kV Bus		0.90		0.91

Table 3-3 Voltage Violations (Given in p.u. Voltage) for Big Stone II Interconnection Study

3.1 Upgrades Identified from Interconnection Study

Based on the overall system performance during steady state conditions, the Big Stone II interconnection study has identified that the following upgrades will be necessary to the existing transmission system for connecting the Big Stone II project with alternative 1. The upgrades shown in Table 3-4 are in addition to the new facilities (described in Table 3-1) that are included as part of transmission alternative 1.

1. Increase capacity of Morris 230/115 kV Transformer
2. Increase capacity of Big Stone to Browns Valley 230 kV Line
3. Increase capacity of Big Stone to Highway 12 115 kV Line

Table 3-4 Required Upgrades for Transmission Alternative 1

Implementing transmission alternative 2 to connect the Big Stone II project to the system will also require upgrades to the existing system. These upgrades are shown below in Table 3-5 and are in addition to the new facilities that are included as part of alternative 2.

1. Increase capacity of Ortonville to Johnson Jct. 115 kV Line
2. Increase capacity of Johnson Jct. to Morris 115 kV Line
3. Increase capacity of Big Stone to Browns Valley 230 kV Line
4. Install capacitor bank in Willmar area to mitigate low voltages

Table 3-5 Required Upgrades for Transmission Alternative 2

3.2 Updates to Alternatives since Interconnection Study

The transmission studies for Big Stone II were being performed at the same time as several other aspects of the project. Other aspects of the project under development during the transmission studies included the MN route application, the SD route application, the Federal Environmental Impact Study (FEIS), and the MN CON Application. Through these parallel efforts, transmission planning personnel were fully engaged in coordinating the electrical characteristic of each transmission alternative with the route feasibility process.

During the route review for alternative 1, it was determined that the 1.25 mile corridor leading to and from the Ortonville substation is already congested with three separate 115 kV lines. Getting a new 230 kV line into and out of the Ortonville substation would have required a wider right-of-way and would create a real challenge during the construction process with nearby transmission lines. Furthermore, the physical space within the substation fence at Ortonville would not allow for a new 230/115 kV transformer without expanding the current size of the substation, which would have required acquiring additional property for substation expansion. An additional study was initiated at OTP to determine alternatives for bypassing the Ortonville substation connection and running the new 230 kV line from Big Stone directly to the Johnson Jct. substation. The conclusion from that study determined that the presence of the Canby 230/115 kV substation with a 115 kV line from Canby to Appleton would allow for an effective method for serving the existing 115 kV system during post-contingent conditions by closing the 115 kV loop from Big Stone around to Appleton and Canby with 230 kV sources at Big Stone and Canby.

Since this determination was made during the middle of the Delivery Service Study, the Ortonville 230/115 kV transformer was removed from alternative 1 for the study work completed as part of Phases 3, 4 and eventually Phases 5 and 6.

The existing Willmar substation has a 230 kV bus that was initially assumed to be an optimal location for the new Big Stone – Willmar line included as part of alternative 2. During discussions with Great River Energy (GRE), a coordinated transmission plan between Big Stone II and GRE was developed to better meet the needs of the Big Stone II project while also addressing the future load serving concerns GRE has with the Willmar area. An update made to alternative 2 through these discussions included a new 230/69 kV transformer with the 230 kV interconnection. Through discussions with GRE, it was determined that a second 230/69 kV source into the Willmar area from Big Stone eliminated the need for the 115/69 kV delivery that currently exists at Willmar. The additional 230/69 kV transformer at Willmar and the removal of the 115 kV deliveries were only added to the models for Phase 4 of the Delivery Study since this information was not solidified until well into the Delivery Study. Any subsequent analysis (Phase 5 and 6) will update the modeling of alternative 2 to capture the agreed plan between the Big Stone II project and GRE.

4.0 Study Procedure

The Big Stone II project is unique in that it consists of a variety of participants from investor owned utilities, public power districts, generation and transmission cooperatives, and municipals/municipal power agencies. The current make-up of the project includes utilities that are both in MISO and MAPP. One comprehensive study is being completed with several different phases in an effort to meet the requirements of both MAPP and MISO.

4.1 Background of Study

In order to ensure that all study requirements were met during this study, various conference calls have been held with the project participants, MISO, WAPA and other interested transmission owners in order to agree on a common study procedure and assumptions. The delivery study consists of six phases as described below.

4.1.1 Phase 1 – 2009 Summer Peak Scenario

The first phase of the Big Stone II Delivery Study included a 2009 summer peak condition with only confirmed reservations included on the system. After some discussion with MISO, it was determined that a 2009 summer peak case was readily available that included all of the known confirmed reservations from both MISO and MAPP. MISO had been maintaining this model from previous studies and was determined to be an appropriate starting point. This particular model was based on the NERC 2003 series 2009 summer peak model with the MAPP region representation updated with the 2009 summer peak information from the MAPP 2004 series models. Numerous updates had already been performed on the case, including adding facilities currently under construction for southwest Minnesota wind outlet.

This case includes confirmed wind reservations from the Buffalo Ridge area of approximately 878 MW, which includes the majority of the wind requests that are on the MISO OASIS ahead of the Big Stone II transmission service requests that were grouped into MISO project A190.

4.1.2 Phase 2 – 2009 Summer Peak Scenario

The 2009 summer peak models obtained from the Midwest ISO for the Phase 1 system impact study contained all of the known confirmed reservations from both the MISO and WAPA OASIS listings. As part of the Phase 2 study, all queued reservations from the MISO and WAPA OASIS ahead of the Big Stone II transmission service requests and are still in study mode that could potentially have an impact on the requested deliveries out of Big Stone II were added to the initial Phase 1 study models to create new cases for Phase 2.

In order to get consensus of which prior queued transmission reservations may have an impact on the Big Stone II deliveries, a conference call was held on Friday, February 4, 2005 between the transmission representatives from the interested utilities to discuss critical modeling assumptions for the upcoming phases of the study. During this conference call, WAPA and MISO OASIS listings were scrutinized in great detail to determine which transmission service reservations should be included in the model for Big Stone II. Input from the participants of the conference call was noted and carried forward for the model building efforts of Phases 2 through 4 of the delivery studies.

During review of the OASIS reservations, it was determined that there were three transmission service reservations on the WAPA OASIS that had a queue date ahead of the Big Stone II requests that requested service to the MISO system. However, corresponding TSR's on the MISO OASIS to connect the WAPA TSR's to service on the MISO system had been queued after (or have not even been made yet) the Big Stone II requests. These three reservations were modeled separately giving way to another set of study models in evaluating the impacts due to the Big Stone II transmission service requests.

These reservations were:
- 200 MW at White 345 kV bus (White Wind Farm) to XEL
- 168 MW from BEPC to XEL
- 200 MW from BEPC to GRE

The models used for the Phase 2 study without the WAPA partial path reservations are referred to as the "Phase 2a" study and focused primarily on the MISO facilities that had to honor MISO reservations prior to Big Stone II. Likewise, the models with the WAPA partial path reservations included are referred to as "Phase 2b", which focused more on the MAPP non-MISO facilities that would subject the Big Stone II reservations to a few more prior queued reservations on the WAPA/IS system. Going forward for Phases 3 and 4, there was a similar process followed to ensure that these partial path reservations were accurately reflected within separate study models. Note that with the exception of the transmission service requests associated with the White wind farm, the remaining requests might not have been modeled in their entirety. The amount was dependent upon general system biases, and available generation to source the reservations from.

After all of the simulations and most of the analysis had been completed, the request for the 200 MW sourcing from a wind farm near White SD was refused on the WAPA/IS OASIS. Follow-up analysis will be completed to determine what impact this will have, if any, on the Big Stone II project. This is true for all Phase 2 through Phase 4 results shown that include IS partial path requests. This information was known too late to make it into this report.

4.1.3 Phase 3 – 2014 Summer Peak Scenario

Phase 3 studied out year summer peak conditions utilizing a powerflow model based on the NERC 2004 series 2014 summer peak model. MISO provided a version of this model, with some updates to the MISO footprint. These updates were external to MAPP. MAPP updates were made based on updates posted on the MAPP Member website, and comments received from Transmission Owners. Such updates included southwest Minnesota wind facilities, Nebraska City 2 upgrades, changes to Rapid City DC tie modeling, and numerous rate changes, and smaller topology changes. Interested transmission owners in the MAPP region were given the opportunity to review the base model before it was utilized.

Similar to the Phase 2 study models, the Phase 3 models had one set of models with prior queued reservations on the WAPA and MISO OASIS (referred to as Phase 3a) and a separate set of models developed with the IS partial path requests included (referred to as Phase 3b). This phase included a 200 MW partial path request from a new generator at White to the MISO footprint that has since been refused on the WAPA/IS OASIS.

4.1.4 Phase 4 – 2011 Winter Peak Scenario

Phase 4 studied winter peak conditions with a high export level from the U.S. to Manitoba. After a lengthy initial discussion between MISO, OTP and MRES, the export level that was determined to be appropriate was 700 MW into Manitoba. The model was based on a NERC 2004 series 2011 winter peak model. The base model development for this model was similar to the Phase 3 model development, except from of course incorporating updates to winter ratings where information was available, as opposed to summer ratings. Transmission Owners were offered the opportunity to review the base model before it was utilized for the study.

Again for Phase 4, separate cases were developed for both the prior queued reservations ahead of Big Stone II in both the WAPA/IS and MISO OASIS list (referred to as Phase 4a) as well as for the WAPA partial path requests (referred to as Phase 4b). This phase also assumed a 200 MW partial path request on the IS OASIS sourcing from a new generator near White, SD, and sinking in MISO. The request has since been refused on the WAPA/IS OASIS.

4.1.5 Phase 5 – Summer Off-Peak Scenario

Phase 5 is unique to the MAPP DRS requirements in that MISO does not require steady state contingency analysis of an off-peak condition with stressed MAPP stability interfaces. Therefore, a summer off-peak case is being developed to perform steady state contingency analysis on to test the performance of the transmission system with Big Stone II on-line while having the Manitoba Hydro Export (MHEX), the North Dakota Export (NDEX), and Minnesota – Wisconsin Stability Interface (MWSI) at their maximum simultaneous levels of 2175 MW, 2080 MW (pre-Big Stone II), and 1480 MW (pre Arrowhead – Weston); respectively.

This analysis has not yet started, but is anticipating using the latest Northern MAPP Operating and Review Working Group (NMORWG) stability package powerflow models. After some discussion with local transmission owners, it has been determined that this model is the most appropriate for this type of study since the generation and transmission are more closely matched than what is typically found in many of the interconnection models.

4.1.6 Phase 6 – High-Level Facility Study

Upon completion of Phases 1 through 5, a master list of thermally related constraints and voltage-limited constraints due to Big Stone II will be identified. Phase 6 is planned to begin testing various fixes to the transmission system in order to address any constraints caused by Big Stone II in each of the previously identified models discussed above.

In addition, Phase 6 will also test the 345 kV alternative associated with Big Stone II, which includes increasing the voltage of the Big Stone – Canby – Granite Falls line to 345 kV and tying into the proposed Brookings County – Southeast Metro 345 kV line being developed by CapX. It is anticipated that upgrading the "southern" line out of Big Stone to 345 kV will alleviate some of the previously identified constraints discovered during the 230 kV analysis from Phases 1 through 5.

There is also the possibility of having some Big Stone II related impacts be addressed by other CapX or MTEP (MISO Transmission Expansion Plan) projects. Any of the high voltage transmission projects in this region that may offset potential Big Stone II related impacts would also be tested during the Phase 6 study. Such analysis may include sensitivity to the Fargo – Alexandria – Monticello 345 kV line or the Hampton Corners – Rochester – LaCrosse 345 kV line.

This analysis is expected to get underway early in 2007 and will be an on-going process until a mitigation measure is identified for each of the previously identified constraints from the 230 kV analysis included in Phases 1 through 5.

4.2 Study Criteria and Methodology

4.2.1 Screening Criteria

This Delivery Service Study focused on steady state contingency analysis and flowgate analysis. A full contingency analysis has been completed on the various models created for this study in order to identify any constraints associated with the assumed deliveries of power from the Big Stone II generator to the project participants.

Steady state contingency analysis performed during this Delivery Service Study simulated single contingencies of all branches with a voltage level of 115 kV and higher within the following PSS/E powerflow model defined balancing areas:

- Area 331 – Alliant Energy West (ALTW)
- Area 600 – Xcel Energy (XEL)
- Area 608 – Minnesota Power (MP)
- Area 613 – Southern Minnesota Municipal Power Agency (SMMPA)
- Area 618 – Great River Energy (GRE)
- Area 626 – Otter Tail Power Company (OTP)
- Area 633 – Muscatine Power and Water (MPW)
- Area 635 – MidAmerican Energy Company(MEC)
- Area 640 – Nebraska Public Power District (NPPD)
- Area 645 – Omaha Public Power District (OPPD)
- Area 650 – Lincoln Electric System (LES)
- Area 652 – Western Area Power Administration (WAPA)
- Area 667 – Manitoba Hydro (MH)
- Area 672 – Saskatchewan Power Corporation (SPC)
- Area 680 – Dairyland Power Cooperative (DPC)

In addition, valid multiple element contingencies were also simulated during the contingency analysis that were based on the standard MAPP contingency file.

In flagging thermal and voltage violations during contingency analysis, facilities of 69 kV or higher in the following PSS/E power flow model defined balancing areas were monitored:

- Area 331 – Alliant West (ALTW)
- Area 600 – Xcel Energy (XEL)
- Area 608 – Minnesota Power (MP)
- Area 613 – Southern Minnesota Municipal Power Agency (SMMPA)
- Area 618 – Great River Energy (GRE)
- Area 626 – Otter Tail Power Company (OTP)
- Area 633 – Muscatine Power and Water (MPW)
- Area 635 – MidAmerican Energy Company (MEC)
- Area 640 – Nebraska Public Power District (NPPD)
- Area 645 – Omaha Public Power District (OPPD)
- Area 650 – Lincoln Electric System (LES)
- Area 652 – Western Area Power Administration (WAPA)
- Area 667 – Manitoba Hydro (MH)
- Area 672 – Saskatchewan Power Corporation (SPC)
- Area 680 – Dairyland Power Cooperative (DPC)

For steady state contingency analysis during this Delivery Service Study, appropriate regional and local criteria were applied when screening for transmission system constraints. If loading on a particular facility exceeds the acceptable loading levels, and the distribution factor is above applicable cutoffs, it is considered a Significantly Affected Facility (SAF). In order for a non-flowgate branch to qualify as a SAF, one of the following criteria must apply:

- Loading level above 100% of normal rating with an OTDF/PTDF ≥ 2% (12 MW) for MAPP non-MISO facilities. Emergency ratings were only utilized when there are identified ways to get the flow back to the normal rating or lower within the time frame of the emergency rating. System intact constraints are evaluated against the normal rating.
- Loading level above 100% of EM rating with an OTDF ≥ 3% (18 MW), or above 100% of normal rating with a PTDF ≥ 5% (30 MW) for MISO facilities.

(Note: The powerflow models utilized for this study were adjusted so as to have uniform use of the PSS/E rating fields. Rate A is always the normal/continuous rating. While MAPP series models have Rate C as the emergency rating, other entities typically use Rate B for this purpose. The models utilized for this study were adjusted to have all emergency ratings in the Rate B field).

In order to include all SAF within the output of the contingency analysis all phases monitored all facility loadings greater than 100% of Rate A for system intact and contingency conditions. The output of loading violations obtained from each phase of the study is included within the detailed appendices of this report; however, only a summary of those considered as a SAF are included within the body of this report. Efforts have been made to verify branch ratings through contacts with local Transmission Owners.

For classification of a voltage concern as a SAF, the voltage constraints identified as a result of Big Stone II must meet one of the following criteria for either a MISO facility or a MAPP non-MISO facility:

- Voltage increase greater than or equal to 1% for buses not meeting pre or post-contingent high voltage criteria.
- Voltage decrease greater than or equal to 1% for buses not meeting pre or post-contingent low voltage criteria.

Different transmission owners within this region have slightly different criteria for pre-contingent and post-contingent voltage levels expressed as a percent of the nominal bus voltage. Therefore, efforts were made to meet the published criteria included within the most recent version of the *MAPP Members Reliability Criteria and Study Procedures Manual*. During the contingency analysis, voltage criteria applied during both system intact and contingency conditions included a 5% deviation from nominal (0.95 p.u. ≤ V ≤ 1.05 p.u.). The output of voltage violations obtained from each phase of the study is included within the detailed appendices of this report; however, only a summary of those considered as a SAF are included within the body of this report. Efforts have been made to verify voltage violations through additional analysis or by verification from local transmission owners.

Flowgate analysis completed as part of this Delivery Service Study investigated the potential impact these transmission service reservations from Big Stone II may have on defined flowgates in the MAPP and MISO footprint. In order for a flowgate to be flagged as significantly impacted by the Big Stone II reservations, the following criteria were used during this study:

- Impact on a MAPP non-MISO OTDF flowgate of more than 3%, or on a MAPP non-MISO PTDF flowgate of more than 5% for flowgates with inadequate Available Flowgate Capacity (AFC). This was done utilizing the flowgate list utilized by the new MAPP webOASIS automatic request evaluation environment, as well as with the perhaps more familiar list used in the old MAPP request evaluation tool. Regardless of loading on the flowgate, facilities impacted by more than the DF criteria are flagged in this report.
- Impact on a MISO OTDF flowgate of more than 3% or on a MISO PTDF flowgate of more than 5% with inadequate capacity. This was done utilizing a flowgate list provided by MISO.

Any facility that meets the criteria as a SAF or an impacted flowgate during this Delivery Service Study will be discussed in the following sections of this report.

4.2.2 Tools

Steady state analysis utilized an AC contingency simulation software tool based on PSS/E and Microsoft Excel developed by Great River Energy (GRE). The tool applies branch outages in a user-defined area while monitoring voltage and loading levels within another user-defined area. This software tool is very similar to the PSS/E ACCC activity, but has the ability to output the results of the analysis into a file easily compatible with Microsoft Excel. This software tool is very similar to the ACCC activity in that single branch outages as well as multiple branch outages are simulated in accordance with switching procedures contained within an auxiliary file.

During the automated contingency simulations, numerous contingencies did not converge. Some contingencies seemed to make the case “blow up”, i.e. the mathematical solution diverged when using PSS/E’s Full Newton Raphson and Fast Decoupled Newton solution algorithms. (The GRE IPLAN program uses the FNSL, and FDNS functions in PSS/E). Other contingencies did not converge seemingly due to toggling transformer taps or switched shunt capacitor banks not being able to settle during the pre-defined maximum amount of iterations. The GRE IPLAN program provides output to the user concerning the general status of solving each contingency simulated. All relevant contingencies reported as non-convergent after performing the automatic mass contingency analysis were reran in a more manual fashion to obtain a solved case. Techniques utilized to obtain a solution were to manually control toggling capacitors, use of temporary synchronous condensers, and artificially gradually increase the impedance of a circuit element before removing it from service. (By relevant contingencies is meant contingencies that could interact with the Big Stone II project. For example, there were some sub-transmission lines in Saskatchewan that did not converge that were not re-simulated given Saskatchewan's limited connectivity to the US system.)

Flowgate analysis was performed to satisfy MAPP and MISO criteria. The DFCALC program was utilized to determine the distribution factor on all flowgates defined in the new MAPP OASIS hosted by OATI, as well as the more traditional list of flowgates utilized by the previously used MAPP OASIS Request Evaluation tool. In addition, flowgate analysis was performed using the MISO flowgate list provided in a format compatible with the MUST software to satisfy MISO requirements.

4.2.3 Methodology

This study has included several contingency analysis simulations with results from the "existing system" (pre-Big Stone II) compared against the results obtained for the same contingency analysis of the Big Stone II cases with each transmission alternative. Furthermore, those phases that included WAPA partial path reservations were also treated separately from the non-partial path cases as contained within each phase of the study.

Any facility that is classified as an SAF during the steady state contingency analysis of any phase of this study will be discussed in the following sections, as well as OTDF flowgates impacted by 3% or more, and PTDF flowgates impacted by 5% or more.

5.0 Model Development

The model development stage of any study is one of the key aspects to a successful study. The Big Stone II Delivery Study has involved a massive model building effort with input collected from several Transmission Owners. Topology of future planned projects was reviewed extensively to insure that the appropriate modeling of any new facilities were as accurate as possible. This section will discuss the general topology changes made to the various models included as part of this study.

5.1 Phase 1 and Phase 2 Models

The Phase 1 model included within the Delivery Study was a 2009 summer peak case with only confirmed reservations. This case was obtained from the Midwest ISO, which had applied several updates to the model to account for all of the confirmed reservations. The most notable aspect of this model was the inclusion of the SW MN wind facilities that represented Xcel Energy's expected system configuration for accommodating up to 825 MW of wind. Along with these transmission reinforcements, an idev obtained from MISO simulated 878 MW of generation on-line from resources in SW MN. Although several of these requests were not "confirmed" when the Phase 1 study for Big Stone II was initiated, it was anticipated that these reservations would be confirmed before Big Stone II so they were all modeled as "confirmed" reservations ahead of Big Stone II.

Once this Phase 1 model had the SW MN wind and transmission facilities in-service, the associated Big Stone II facilities and dispatch was applied to the case in preparation for the AC contingency analysis. More details related to the modeling of Big Stone II can be found in section 6.1 of this report.

The Phase 2 model used for this Delivery Study augmented the Phase 1 model by embedding the prior queued transmission reservations ahead of Big Stone II that have the potential to stress the transmission system, but are still under investigation by means of on-going studies. In addition to the large shift in reservations included as part of the Phase 2 model, the following topology changes were also included in the Phase 2 models:

- Update branch ratings in ALTW area
- Update modeling of Lake Yankton SVC
- Update branch ratings in XEL area
- Update branch ratings in GRE area
- Adjust generation patterns in GRE area
- Refine modeling of Rapid City DC tie

A more complete listing of model changes made to the Phase 2 models can be found in the model change log located within Appendix F. Once the base Phase 2 model was deemed complete, Big Stone II with its associated facilities and dispatch was applied to the case in preparation for the AC contingency analysis. More details related to the modeling of Big Stone II with the two transmission alternatives for the Phase 2 study can be found in section 6.2.

5.2 Phase 3 and 4 Models

The Phase 3 and 4 models used during this Delivery Study had several of the same updates applied to both of them and therefore will be covered in a common section.

The Phase 3 model represented 2014 summer peak conditions and was based on the NERC 2004 series 2014 summer peak model. The Phase 4 model represented a 2011 winter peak condition with Manitoba Hydro importing 700 MW. This model was based on the 2004 NERC series model with the MAPP representation taken from the 2004 series 2011 MAPP series winter peak model.

Knowledge from the model building efforts of Phases 1 and 2 were again applied to this model with numerous other topology updates based on feedback from MAPP and MISO Transmission Owners. Some of the most notable topology updates included in the Phase 3 and 4 models included:

- Add the Blue Lake "loop-in" from McLeod instead of Black Dog
- Update several modeling deficiencies in SW MN (voltage settings, ratings, shunts, etc.)
- Include the Arrowhead – Stone Lake – Gardner Park 345 kV Line
- Include Mankato area upgrades
- Update Bismarck area branch ratings and impedances
- Include the Lakefield – Wilmarth 345 kV series compensation
- Include the 2nd Maple River 230/115 kV transformer (187 MVA)
- Include anticipated Sherco area improvements with new 345/115 kV and 115/69 kV transformers
- Update 115 kV line parameters between Grant County and Douglas County
- Include Wilmarth Calpine project (379 MW)
- Include the Groton CT (120 MW)
- Include miscellaneous BEPC co-gen (heat recovery) units throughout system (22.5 MW total)
- Include West Faribault generation (250 MW)
- Include Appleton – Canby 115 kV Line
- Include BEPC Fort Thompson and Edgeley Wind Farms (~ 80 MW total)
- Update various branch ratings and impedances in WAPA balancing area
- Added Nebraska City #2 with its associated upgrades (400 MW)
- Added Kandiyohi Tap along the Willmar – Paynesville 230 kV Line

A more comprehensive list of all the model changes applied to the Phase 3 and 4 models can be found within Appendix F. Once the base models were developed for the Phase 3 and 4 models, the Big Stone II project was added into the models in preparation for the steady state contingency analysis. More details on the specific modeling of the Big Stone II generator with its associated facilities can be found within subsequent sections of this report.

5.3 Phase 5 Model

Phase 5 of the Big Stone II Delivery Study will investigate the latest NMORWG summer off-peak case. The Phase 5 study models are currently under development and will likely include all of the previously mentioned topology changes. Another aspect of the Phase 5 study will be to maximize flows across the critical interfaces within northern MAPP. In accordance with MAPP DRS guidelines for off-peak studies, existing generation within North Dakota will be set to URGE to insure that the reservations associated with Big Stone II do not take away from the capability of existing units to deliver there full output.

5.4 Model Development Common to All Phases

During the model building process for this study, there were some aspects that were common to all phases. The first aspect was the modeling of existing generators in the vicinity of Big Stone. When developing the base case models for each phase of the study, the existing Big Stone generator was scheduled at a maximum net output of 475 MW. In addition, the Lake Preston peaking plant that is located on the 41.6 kV system served from the 115 kV substation in Toronto, South Dakota was also scheduled at full output (22 MW). The two existing coal-fired generators located at the Hoot Lake plant in Fergus Falls were also increased in the models to their maximum output. Making these changes in the model ensured that the existing transmission system out of the Big Stone plant was stressed to its fullest capacity. In order to account for the increases in generation within the Otter Tail Power Company balancing area in the base cases, corresponding generation reductions were taken at the Coyote generating station in the coal fields of North Dakota.

During the creation of these study models, area interchange between the various balancing areas was enforced, which caused the swing generator in each area to adjust slightly during the simulation of these transactions from Big Stone II (Otter Tail Power Company balancing area) to the various generators that were redispatched to absorb the increased generation. This slight adjustment was automatically done by the swing generators in order for each balancing area to serve its respective load and losses while still maintaining the desired interchange with adjacent balancing areas within the set bandwidth. A comparison of the models was completed before contingency analysis began in order to verify that adjustments of each balancing area's swing generator was within reason.

Once results from the analysis started to come in, and they were verified with local transmission owners, some line ratings were identified as too low, and therefore what at first appeared as constraints, are no longer constraints. Table 5-1 provides a list of such updates. All other tables in this report assume these ratings to be the appropriate ones to use:

1. Willmar – Granite Falls 230 kV: Models assumed 239 and 318 MVA for normal and emergency ratings. Per newer information from GRE, it is assumed that the line rating will increase to 382.3 MVA prior to Big Stone II coming online. The rating upgrade is scheduled to take place in 2006.
2. MN Valley – Granite Falls 115 kV: Models assumed a summer rating of 120 MVA normal, and 132 MVA emergency. Based on information from Xcel the appropriate ratings to use for summer conditions are 209 MVA normal rating, and 230 MVA emergency rating.
3. Leland Olds 345/230 kV transformer – largest unit: Models assumed appropriate ratings were 500 MVA normal and 600 MVA emergency. Based on information from BEPC, the correct rating is assumed to be 600 MVA normal and 700 MVA emergency.
4. Antelope Valley – Charlie Creek 345 kV: Models assumed normal summer rating of 240 MVA. Based on information from BEPC, correct rating should be assumed as 538 MVA.
5. Kerkhoven Tap – Kerkhoven 115 kV: Models assumed normal and emergency (for both summer and winter) ratings were 29.9 MVA. Based on information from GRE, the correct rating was assumed as 44.82 MVA. Note that this rating update ultimately did not remove this line from the list of constraints completely, but reduced the amount of scenarios where it was concluded to be a SAF.
6. Bismarck – East Bismarck 115 kV: Models assumed normal summer rating of 107.7 MVA. Based on information from WAPA, the correct rating was assumed as 199.19 MVA.
7. 2nd Wilton 230/115 kV Transformer: Phase 4 identified a potential loading issue on the Wilton 230/115 kV transformer for the loss of the Badoura – Laporte 115 kV line. Review of the models revealed that the second 230/115 kV transformer installed at Wilton by MPC was not included. This overload was dismissed as a possible constraint with the addition of the missing transformer. Not including this transformer within the study models was considered immaterial since this second transformer was installed for load serving reasons and not to support transmission system performance on a regional basis.
8. Edgetown Tap – Pelican Rapids 115 kV: This element was initially flagged as constraint in winter scenarios. With a rating correction to reflect a normal rating of 128 MVA, and an emergency rating of 136 MVA, this facility was not a constraint.

Table 5-1 Facility Changes Made Known After Analysis Was Complete

(Note: For those readers of the report that reviewed the model, or utilized the model for other purposes, these changes have not been applied to the models after the fact. The models have remained as they were when running the automated analysis).

As this report was being written, an error in the MAPP models was discovered on the Rush Lake – Perham 115 kV line. It appears that the line reactance was nearly 1000 times higher than what the real value is. This could be part of the cause of some of the bus voltage issues seen in this area. Sensitivity analysis will be done to investigate this further.

6.0 Steady State Powerflow Analysis Results

6.1 Phase 1 – 2009 Summer Peak Scenario

As with any Delivery Study, the standard starting point is to begin by assessing the impact of a particular project on the transmission system with only confirmed reservations included on the system. After some discussion with MISO, it was determined that a 2009 summer peak case was readily available that included all of the known confirmed reservations from both MISO and MAPP. MISO had been maintaining this model from previous studies and was determined to be an appropriate starting point for this Delivery Study. This particular model was based on the NERC 2003 series 2009 summer peak model with the MAPP region representation updated with the 2009 summer peak information from the MAPP 2004 series models.

This case includes confirmed wind reservations from the Buffalo Ridge area of approximately 878 MW, which includes the majority of the wind requests that are on the MISO OASIS ahead of the Big Stone II transmission service requests that were grouped into MISO project A190.

6.1.1 Model Assumptions Specific for Phase 1

6.1.1.1 Dispatch Assumptions

In order to get the Phase 1 study underway, the Big Stone II participants provided MISO with a dispatch scenario in which they wanted the output from the new generator sunk. This scenario was used as a starting point for the contingency analysis of Phase 1 and is illustrated below in Table 6-1.

BS2 Participant	MW Amount
OTP	107
GRE	107
CMMPA	30
MRES	107
HCPD	50
HUC	50
SMMPA	42
MDU	107
Total =	**600**

Table 6-1 Dispatch Scenario for Study of the Big Stone II Project

The steady state contingency analysis portion of this Delivery Study was performed assuming a generation-to-generation redispatch when simulating the requested transmission service from Big Stone II. In creating the cases for this Phase 1 system impact study, the following generation redispatch patterns shown in Table 6-2 were assumed for Phase 1.

Company	Unit Name	Bus #	MW
OTP	Solway Peaking Plant	63285	50
	Jamestown Peaking Plant	63172	44
	Coyote Generating Station	67315	13
	Sub Total		107
GRE	St. Bonifacious	63021	62
	Lakefield Generating Station	63011	22.5
	Pleasant Valley Station	63006	22.5
	Sub Total		107
CMMPA	Blue Earth	60651	2
	Delano	60882	3
	Fairfax	60727	0.3
	Glencoe	60899	3
	Granite Falls	60691	1.5
	Janesville	60644	0.6
	Kenyon	60795	1.5
	Sleepy Eye	60722	1.5
	New Ulm	60939	4.9
	Willmar	62990	5
	Main Street	60226	6.7
	Sub Total		30
MRES	Watertown Power Plant	67451	50
	Exira	67465	57
	Sub Total		107
HCPD	Cooper Nuclear Station	64709	45
	Laramie River Station	67118	5
	Sub Total		50
HUC	Hutchinson Peaking Plant	62985	50
	Sub Total		50
SMMPA	Fairmont	61936	32.2
	Redwood Falls	61958	8.3
	Litchfield	61912	1.5
	Sub Total		42
MDU	Miles City	66412	14.3
	Glendive Combustion Turbine	67332	30
	Heskett	67345	62.7
	Sub Total		107
	GRAND TOTAL		**600**

Table 6-2 Generation Redispatch Assumptions for Phase 1

During the middle of the Delivery Service Study, the Big Stone II participants informed MISO of an updated participation structure that was very similar to what was being studied. Since the change in the make-up of the project was not significant and since study work for the Phase 1 study had already begun, analysis continued with the current dispatch assumption. The latest dispatch information received from the Big Stone II participants was received in time to update the dispatch for the Phase 3 and 4 analyses that are discussed in subsequent sections.

A total of three cases were investigated through this Phase 1 system impact study. These three cases allowed for a direct comparison of the base case to the study cases created for analysis of the Big Stone II project with each of the transmission alternatives.

6.1.1.2 Topology Assumptions

The Phase 1 model for the Big Stone II Delivery Study had very little modifications done to it compared to the model received from the Midwest ISO. The most notable topology assumption within the base case model was inclusion of the SW MN 825 MW transmission facilities to accommodate the amount of prior queued reservations from generation projects within that area.

Modeling of Big Stone II included both transmission alternatives (described above in section 3.0). Transmission alternative 1 included a new 230 kV line from Big Stone to Morris and from Big Stone to Granite Falls with new 230/115 kV transformers at Ortonville, Johnson Jct., and Canby. Based on the current knowledge of the Big Stone II transmission plan, the inclusion of the Ortonville 230/115 kV transformer for alternative 1 is no longer a valid assumption since routing and permitting efforts have determined physical barriers to accommodating a termination with a transformer into the existing Ortonville substation. With this new information for alternative 1, additional analysis has not been performed since this change in topology did not create a large change in the power distributions out of the Big Stone plant. This is based on knowledge of the Phase 3 and Phase 4 analyses, which did not include the Ortonville transformer in transmission alternative 1.

Transmission alternative 2 included a new 230 kV line from Big Stone to Willmar and from Big Stone to Granite Falls with a new 230/115 kV transformer added at Canby.

Both cases included a new generator step-up transformer at Big Stone to connect the Big Stone II generator to the existing 230 kV bus. Besides these Big Stone II specific modeling changes, the base model received from MISO was essentially left untouched before adding the Big Stone II facilities.

6.1.2 Analysis Results of Big Stone II with Transmission Alternative 1

This section of the report will include only a portion of the full results obtained from the steady state contingency analysis. This portion will focus only on the outstanding violations for alternative 1 that are classified as a SAF based upon the criteria identified within section 4.2.

Automap diagrams obtained from the scenario 1 dispatch for the existing system, alternative 1, and alternative 2 are included within Appendix A.

6.1.2.1 Thermal Constraints

The thermal constraints identified during the Phase 1 analysis of alternative 1 indicated 4 transmission facilities that are overloaded. These facilities are shown below in Table 6-3. Since there was not any IS partial path cases investigated during Phase 1 (only included confirmed reservations), there is only one set of results available for alternative 1.

Appendix C includes detailed contingency analysis results for the Phase 1 study. The thermal constraints included below only include those facilities that were classified as a SAF based on the criteria described above in section 4.2.

Further discussion of the constraints identified below will be included within section 8.0 “Conclusion” along with the constraints identified in the other phases of this study.

Constraint Element	Contingency Example	Owner	Rate A	EM Rate	% DF High	Highest MVA Loading
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63329 WAHPETN4 230 66754 MAPLE R4 230 1 SW 959	MRES/OTP	96	105	6.17	113.74
66203 FARGO 869.0 67000 MAPLE R869.0 1	60133 SHEYNNE4 230 66435 FARGO 4 230 1	MPC	62	68	2.12	72.63
60742 PANTHER869.0 63054 PANTHER4 230 1	62980 MCLEOD 4 230 63054 PANTHER4 230 1	XCEL	70	87.5	3.75	91.58
60133 SHEYNNE4230 66435 FARGO 4 230 1	63369 JAMESTN3 345 66791 CENTER 3 345 1	XCEL	388	388	7.52	392.7

Table 6-3 Summary of Phase 1 Thermal Constraints for Alternative 1

6.1.2.2 Steady State Voltage Constraints

Steady state contingency analysis of alternative 1 during the Phase 1 study indicated that the Willmar area had depressed voltages aggravated by the addition of Big Stone II with alternative 1.

Table 6-4 includes a summary of the steady state voltages issues observed for alternative 1 during the Phase 1 study. This table only lists those bus voltage concerns that were found to be significantly impacted by the BSP II project. A full listing of the voltage results obtained from the contingency analysis results can be found in Appendix C.

Further discussion of the constraints identified below will be included within section 8.0 “Conclusion” along with the constraints identified in the other phases of this study.

Bus #	Bus Name	kV	System Intact Voltage w/o BSP II [%]	System Intact Voltage with BSP II [%]	Worst Contigency (causing lowest voltage)	Post cont. w/o BSP II [%]	Post cont. with BSP II [%]	Worst change in voltage [%]
62425	Willmar	115	99.00	98.42	63050 WILLMAR4 230 66550 GRANITF4 230 1	94.58	91.67	-2.91

Table 6-4 Summary of Phase 1 Steady State Voltage Issues for Alternative 1

6.1.2.3 Loss Analysis

Balancing area losses were calculated for the MAPP region along with ALTW to determine how losses are impacted by BSP II with alternative 1. The results in Table 6-5 indicate that the largest loss impacts occur in the XEL and OTP balancing areas. The new 230 kV transmission lines included as part of the Big Stone II project were modeled as being a part of the OTP balancing area.

Balancing Area	Load (MW)	Base	Alt #1	Δ MW
Area 331 (ALTW)	4612.6	107.7	108.1	0.4
Area 600 (XEL)	10833.2	390.1	403.9	13.8
Area 608 (MP)	1686.7	98.6	98.4	-0.2
Area 613 (SMMPA)	330	0.9	0.9	0.0
Area 618 (GRE)	1637	106.1	110.1	4.0
Area 626 (OTP)	1826	80.1	94.7	14.6
Area 633 (MPW)	174.2	1.1	1.1	0.0
Area 635 (MEC)	5730.4	132.4	133.2	0.8
Area 640 (NPPD)	3231.4	113.6	112.8	-0.8
Area 645 (OPPD)	2632.9	28.2	27.9	-0.3
Area 650 (LES)	836	9.9	9.9	0.0
Area 652 (WAPA)	3217.5	202.7	206.7	4.0
Area 667 (MH)	2964	298.8	298.6	-0.2
Area 680 (DPC)	972.2	78.3	77.8	-0.5
Total =	**40684.1**	**1648.5**	**1684.1**	**35.6**

Table 6-5 Losses (in MW) from Phase 1 Model for Alternative 1

6.1.3 Analysis Results of Big Stone II with Transmission Alternative 2

This section of the report will include only a portion of the full results obtained from the steady state contingency analysis. This portion will focus only the outstanding violations for alternative 2 that are classified as a SAF based upon the criteria identified within section 4.2. The only difference between this section and the previous section is the facilities assumed to exist with Big Stone II. This section will only focus on the results obtained from the steady state simulations with alternative 2 versus the previous section, which focused on alternative 1. Sink definitions, dispatches and all other aspects of the alternative 1 case remained the same for the alternative 2 case.

Automap diagrams obtained from the scenario 1 dispatch for the existing system, alternative 1, and alternative 2 are included within Appendix A.

6.1.3.1 Thermal Constraints

The thermal constraints identified during the Phase 1 analysis of alternative 2 indicated several additional 69 kV facilities in the vicinity of Willmar. These facilities are likely a result of the additional injection of power into the local 69 kV system from Big Stone II with the outage of a parallel high voltage transmission line. Sensitivity analysis of these 69 kV overloads in the Willmar area should be tested for their validity with the addition of GRE's proposed Kandiyohi 230/69 kV substation along the Willmar and Paynesville 230 kV line. This proposed substation was not included in the Phase 1 models, but was included within the Phase 3 and 4 models, which did not indicate local 69 kV thermal issues in the vicinity of Willmar.

In addition, there was also a few of the same facilities identified for alternative 2 that were also identified for alternative 1. These include the Grant County – Morris 115 kV line and the Panther 230/69 kV transformer.

The Paynesville area concerns indicate that outage of the Paynesville – Wakefield 115 kV line results in high post-contingent loadings on the underlying 69 kV system. The 115/69 kV transformers at Paynesville along with the Paynesville – Roscoe – Munson – Farming 69 kV line exhibit loadings in excess of their emergency ratings. The 69 kV line to Farming has been identified within the BRIGO study as being a required upgrade for high generation penetrations from SW MN and is noted in Table 6-6.

Appendix C includes all of the detailed results for the thermal analysis performed for Phase 1. Further discussion of the constraints identified below will be included within section 8.0 "Conclusion" along with the constraints identified in the other phases of this study.

Constraint Element	Contingency Example	Owner	Rate A	EM Rate	% DF High	Highest MVA Loading	Note
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63329 WAHPETN4 230 66754 MAPLE R4 230 1 SW 959	MRES/OTP	96	105	3.75	100.71	3
60156 PYNSVIL7 115 60760 PAYNES 869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	XCEL	47	61	3.4	65.82	
60156 PYNSVIL7 115 60760 PAYNES 869.0 2	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	XCEL	47	61	3.37	65.12	
60742 PANTHER869.0 63054 PANTHER4 230 1	62980 MCLEOD 4 230 63054 PANTHER4 230 1	XCEL	70	87.5	3.7	91.33	
62437 SVEATAP869.0 62438 LITCHTP869.0 1	60150 MNVLTAP4 230 63054 PANTHER4 230 1	GRE	36.2	36.2	3.18	44.66	1
62427 WILLMAR869.0 63050 WILLMAR4 230 1	62005 KERKHOT7 115 62425 WILLMAR7 115 1 SW 981	GRE	84	84	4.15	93.52	1
62427 WILLMAR869.0 62437 SVEATAP869.0 1	60150 MNVLTAP4 230 63054 PANTHER4 230 1	GRE	45.5	45.5	3.15	48.32	1
60760 PAYNES 869.0 62835 ROSCOTP869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	XCEL	48	52.8	8.8	60.88	2
62835 ROSCOTP869.0 62837 MUNSNTP869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	XCEL	48	52.8	8.8	58.34	2
60710 FARM TP869.0 62837 MUNSNTP869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	XCEL	48	52.8	8.8	55.59	2

[1] Installation of the proposed Kandiyohi 230/69 kV substation may alleviate these loading issues.

[2] These facilities were identified within the BRIGO study and are likely to be mitigated through upgrades by Xcel Energy for Buffalo Ridge Wind.

[3] Element's normal rating is violated, but not the emergency rating. Operating Procedure might be permissible for mitigation.

Table 6-6 Summary of Phase 1 Thermal Issues for Alternative 2

6.1.3.2 Steady State Voltage Constraints

The steady state voltage issues identified for alternative 2 during the Phase 1 study identified a low voltage condition at two Glenwood (MN) 69 kV buses. A brief description of this low voltage issue identified for alternative 2 is as follows.

- Glenwood 69 kV buses: The 69 kV buses at Glenwood experience voltage levels below 0.95 p.u. for system intact conditions with the addition of Big Stone II with transmission alternative 2. Voltage issues on the 69 kV system around Glenwood have appeared for the Phase 3 and 4 analysis. Sensitivity analysis to a reactive solution in the Alexandria area has shown that a system reconfiguration with the addition of capacitance in the Alexandria area will improve voltage profiles at Glenwood. These findings from the Phase 3 and 4 analysis should be verified for this Phase 1 case before they can be discounted from the list of issues for Big Stone II with alternative 2.

Table 6-7 illustrates the voltage violations encountered during the Phase 2 contingency analysis of Big Stone II with alternative 2. This table only lists those bus voltage concerns found to be significantly impacted by the BSP II project. A full listing of the voltage results obtained from the steady state contingency analysis for the Phase 1 models can be found in Appendix C.

Further discussion of the constraints identified below will be included within section 8.0 “Conclusion” along with the constraints identified in the other phases of this study.

Bus #	Bus Name	kV	System Intact Voltage w/o BSP II [%]	System Intact Voltage with BSP II [%]	Worst Contigency (causing lowest voltage)	Post cont. w/o BSP II [%]	Post cont. with BSP II [%]	Worst change in voltage [%]	Note
60746	Glenwood	69	95.64	94.27	System Intact	95.64	94.27	-1.37	1
62757	Glenwood	69	95.68	94.33	System Intact	95.68	94.33	-1.35	1

[1] Glenwood area voltage issues will likely be mitigated through a system reconfiguration and capacitor bank addition in the Alexandria area.

Table 6-7 Summary of Phase 1 Steady State Voltage Issues for Alternative 2

6.1.3.3 Loss Analysis

Balancing area losses were calculated for the MAPP region along with ALTW to determine how losses are impacted by BSP II with alternative 2. The results in Table 6-8 indicate that the largest loss impacts occur in the XEL, GRE and OTP balancing areas with alternative 2. The new 230 kV transmission lines included as part of the Big Stone II project were modeled as being a part of the OTP balancing area.

Balancing Area	Load (MW)	Base	Alt #2	△ MW
Area 331 (ALTW)	4612.6	107.7	107.9	0.2
Area 600 (XEL)	10833.2	390.1	405.5	15.4
Area 608 (MP)	1686.7	98.6	97.9	-0.7
Area 613 (SMMPA)	330	0.9	0.9	0.0
Area 618 (GRE)	1637	106.1	120.8	14.7
Area 626 (OTP)	1826	80.1	96.7	16.6
Area 633 (MPW)	174.2	1.1	1.1	0.0
Area 635 (MEC)	5730.4	132.4	133.0	0.6
Area 640 (NPPD)	3231.4	113.6	112.7	-0.9
Area 645 (OPPD)	2632.9	28.2	27.9	-0.3
Area 650 (LES)	836	9.9	9.9	0.0
Area 652 (WAPA)	3217.5	202.7	197.3	-5.4
Area 667 (MH)	2964	298.8	299.0	0.2
Area 680 (DPC)	972.2	78.3	77.8	-0.5
Total =	**40684.1**	**1648.5**	**1688.4**	**39.9**

Table 6-8 Losses (in MW) from Phase 1 Model for Alternative 2

6.2 Phase 2a and 2b – 2009 Summer Peak Scenario

The 2009 summer peak models obtained from the Midwest ISO for the Phase 1 Delivery Service Study contained all of the known confirmed reservations from both the MISO and WAPA OASIS. As part of the Phase 2 study, all previously queued reservations from the MISO and WAPA OASIS ahead of the Big Stone II transmission service requests that are still in study mode were added to the initial Phase 1 study models if they were determined as "imperative" to BSP II according to local input from the Transmission Owners. Three new cases were created as part of the Phase 2a study. These cases included the base case (existing system) along with two study cases to encompass both transmission alternatives under evaluation.

In addition, there were three reservations on the WAPA OASIS that had a queue date ahead of the Big Stone II requests that requested service to the MISO system. However, corresponding requests on the MISO OASIS to connect the WAPA reservations to service on the MISO system had fallen after (or have not even been made yet) the Big Stone II requests. These three reservations were modeled separately giving way to another set of three study models in evaluating the impacts due to the Big Stone II transmission service requests. This latter set of models will be referred to as the "partial path" or "IS" cases, which included these additional reservations found in the WAPA OASIS ahead of Big Stone II.

6.2.1 Model Assumptions Specific to Phase 2

6.2.1.1 Dispatch Assumptions

The Big Stone II requests were made to MISO at three separate timeframes. Correspondingly, the three groups of Big Stone II requests were given MISO project numbers of A190, A217 and A219. During development of the models for the Phase 2 study, it has been determined that there is approximately 60 MW's of transmission service requests from the Buffalo Ridge area between the A190 requests and the A217 requests. Likewise, there was one large request made between the A217 and A219 requests that was far removed from the MAPP region. Based on these findings from review of the MISO queue, it was determined that all three groups of Big Stone II requests will be treated as a single request for study purposes occurring at the time that the A219 request was made.

The allocation of the Big Stone II generator was assumed to be the same as that used in the Phase 1 study. Similar to the Phase 1 study, a generation-to-generation redispatch was modeled to simulate the requested deliveries from Big Stone II. Since the base Phase 2 models had a different generation dispatch than the Phase 1 models (due to the inclusion of the previously queued transmission service requests), a slightly different set of generators was used to sink the output from Big Stone II. For dispatch scenario 1, the sink definitions shown in Table 6-9 below were used for the Big Stone II participants. The sink generation definition was used for both the Phase 2a and the 2b study (non-IS cases and the IS partial path cases).

Company	Unit Name	Bus #	MW
OTP			
	Solway Peaking Plant	63285	50
	Jamestown Peaking Plant	63172	44
	Coyote Generating Station	67315	13
	Sub Total		107
GRE			
	St. Bonifacious	63021	62
	Pleasant Valley Station	63006	45
	Sub Total		107
CMMPA			
	Blue Earth	60651	8.2
	Lake Crystal	60700	5.8
	Sleepy Eye	60722	8.6
	New Ulm	60939	7.4
	Sub Total		30
MRES			
	Watertown Power Plant	67451	40
	Exira	67465	67
	Sub Total		107
HCPD			
	Cooper Nuclear Station	64709	45
	Laramie River Station	67118	5
	Sub Total		50
HUC			
	Hutchinson Peaking Plant	62985	50
	Sub Total		50
SMMPA			
	Fairmont	61936	32.2
	Austin	61986	9.8
	Sub Total		42
MDU			
	Miles City	66412	14.3
	Glendive Combustion Turbine	67332	30
	Heskett	67345	62.7
	Sub Total		107
	GRAND TOTAL		**600**

Table 6-9 Generation Redispatch Assumptions for Phase 2

The Phase 2a and 2b studies included a total of 6 steady state cases representing 2009 summer peak conditions. As mentioned previously, 3 of these cases represented the transmission system without the IS partial path reservations and a separate 3 cases represented the transmission system including the IS partial path reservations. Each of these three cases for Phase 2a and 2b included the existing system (base case) plus 2 cases for the alternatives.

6.2.1.2 Topology Assumptions

The Phase 2 models were derived from the Phase 1 models. As previously mentioned in section 4.1.2, there were other topology assumptions made to create the Phase 2 models. The major topology assumptions included refining the modeling of the Lake Yankton SVC and the Rapid City DC tie. Besides these changes, there were also updates applied to branch ratings in the ALTW, XEL, and GRE areas based on input from local Transmission Owners.

Once the previously queued reservations were inserted into the model, Big Stone II and its associated transmission alternatives were added. The modeling of the Big Stone II transmission alternatives was similar to what was completed for the Phase 1 study. Transmission alternative 1 included a new 230 kV line from Big Stone to Morris and from Big Stone to Granite Falls with new 230/115 kV transformers added at Ortonville, Johnson Jct. and Canby. As mentioned in the Phase 1 model, the Ortonville 230/115 kV transformer addition has now been eliminated from the transmission project for alternative 1 based on information gathered from the routing and permitting efforts underway as part of this project. The Phase 2 study included the Ortonville transformer, but in reality it will not be part of alternative 1. With this new information for alternative 1, additional analysis has not been performed since this change in topology does not create a significant change in the power distributions out of the Big Stone plant. This is based on knowledge of the Phase 3 and Phase 4 analyses, which did not include the Ortonville transformer in transmission alternative 1.

As in Phase 1 models, transmission alternative 2 included a new 230 kV line from Big Stone to Willmar and from Big Stone to Granite Falls with a new 230/115 kV transformer added at Canby.

All of the steady state powerflow cases with Big Stone II included a new generator step-up transformer at Big Stone to connect the Big Stone II generator to the existing 230 kV bus.

6.2.2 Analysis Results of Big Stone II with Transmission Alternative 1

A full listing of the Phase 2 contingency analysis results is included within Appendix C, however, this section of the report will only include a portion of the full listing for alternative 1 with those transmission system elements classified as a SAF based upon the criteria identified within section 4.2.

Automap diagrams obtained from the Phase 2 models for the existing system, alternative 1, and alternative 2 are included within Appendix A.

6.2.2.1 Thermal Constraints

Steady state contingency analysis of the Phase 2a and 2b models resulted in more facilities on the transmission system being impacted by the Big Stone II project. These SAF are primarily found in southern MN and east of Big Stone. Table 6-10 below summarizes the thermal issues identified during the contingency analysis of the Phase 2 models with Big Stone II and alternative 1. Table 6-10 includes the results from both the Phase 2a scenario and 2b scenario with alternative 1.

As shown below, there are 3 facilities added to the list of constraints for the Phase 2b analysis that included IS partial paths. Since these facilities are MAPP non-MISO facilities, they are considered to be significantly impacted in the IS partial path case.

Some of the SAF shown in the following table have been identified in previous studies performed for other transmission service requests. In addition, some of the impacted facilities could be highly dependent on the assumed sink definition of Big Stone II. Coordination with MAPP/MISO will be necessary to determine which of the SAF identified below in Table 6-10 are truly the responsibility of Big Stone II.

The table below is only a summary of the full contingency analysis results from the Phase 2 analysis. A full listing of the results from the analysis is within Appendix C.

Further discussion of the constraints identified below will be included within section 8.0 “Conclusion” along with the constraints identified in the other phases of this study.

Constraint Element	Contingency Example	Owner	Rate A	EM Rate	% DF High	Highest MVA Loading w/o IS	Highest MVA Loading w/ IS	Note
34006 LAKEFLD3 345 34007 LAKEFLD5 161 1	34006 LAKEFLD3 345 34007 LAKEFLD5 161 2	ALTW	335	335	4.92	399.83	395.89	
34006 LAKEFLD3 345 34007 LAKEFLD5 161 2	34006 LAKEFLD3 345 34007 LAKEFLD5 161 1	ALTW	335	335	4.92	399.83	395.89	
34007 LAKEFLD5 161 34008 FOX LK 5 161 1	34007 LAKEFLD5 161 34008 FOX LK 5 161 P2	ALTW	160	160	3.98	211.82	221.42	1
34008 FOX LK 5 161 34012 FOXLAKE869.0 1	34009 WINBAGO5 161 61932 RUTLAND5 161 1 SW 889	ALTW	74.7	74.7	3.07	80.53	81.95	
60133 SHEYNNE4 230 66435 FARGO 4 230 1	63369 JAMESTN3 345 66791 CENTER 3 345 1	XCEL	388	388	10.7	422	434.5	
60148 MINVALY7 115 60149 MINVALT4 230 P6	60150 MNVLTAP4 230 66550 GRANITF4 230 1	XCEL	187	215	8.3	x	227.77	2
60150 MNVLTAP4 230 66550 GRANITF4 230 1	63050 WILLMAR4 230 66550 GRANITF4 230 1 SW 928	XCEL	388	427	20.09	431.15	475.39	
60742 PANTHER869.0 63054 PANTHER4 230 1	62980 MCLEOD 4 230 63054 PANTHER4 230 1	XCEL	70	87.5	3.95	99.3	108.37	
62425 WILLMAR7 115 62427 WILLMAR869.0 1	63050 WILLMAR4 230 66550 GRANITF4 230 1	GRE	112	140	3.95	152.51	163.12	
63219 GRANTCO7 115 63220 ELBOWLK7 115 1	63051 HENNING4 230 63052 INMAN 4 230 1 SW 819	MRES	160	160	3.83	x	166.42	
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63329 WAHPETN4 230 66754 MAPLE R4 230 1 SW 959	MRES/OTP	96	105	6.3	121.49	131.03	
66203 FARGO 869.0 67000 MAPLE R869.0 1	60133 SHEYNNE4 230 66435 FARGO 4 230 1	MPC	62	68	2.69	77.02	81.45	
66424 BELFELD3 345 67183 CHAR.CK3 345 1	Loss of both Leland Olds 345/230 kV Transformers	WAPA	239	263	2.75	x	240.3	3

[1] This overload is due to loss of parallel circuit and has been identified in previous studies. MISO is considering operating procedure which would alleviate this overload.

[2] Only flagged for IS scenario, but MISO facility. Not a constraint that Big Stone II would have to mitigate.

[3] This facility is loaded above normal rating, but not emergency rating. Operating guide could be permissible to alleviate constraint.

Table 6-10 Summary of Phase 2 Steady State Thermal Issues for Alternative 1

6.2.2.2 Steady State Voltage Constraints

The voltage issues identified during the Phase 2 analysis of Big Stone II with transmission alternative 1 indicated that some 69 kV buses in the Glenwood area were below acceptable post-contingent voltage levels. In addition, two 115 kV buses in the Willmar area were also impacted by BSP II with alternative 1. A summary of the Phase 2 voltage problems identified in the Glenwood area are summarized below.

- Glenwood Area Voltage Issues: The Alexandria area has been identified as needing reactive support dut to increasing loads in that area during previous studies. These voltage issues are currently under investigation by MRES. The Phase 3 and 4 analysis identified similar low voltage issues in the Glenwood area that were studied with a system reconfiguration and capacitor bank addition around Alexandria. System enhancements in the Alexandria area proved to be an effective method in raising the post contingent voltage levels to within criteria. This sensitivity analysis was not performed on the Phase 2 analysis and therefore will remain as an issue for Big Stone II although it is anticipated that stand alone projects outside of Big Stone II will alleviate this issue before Big Stone II is in-service.

The following Table 6-11 includes a summary of the post-contingent voltage levels identified for the Phase 2a case with Big Stone II in-service with transmission alternative 1. This table only lists those bus voltage concerns found to be significantly impacted by the BSP II project. A full output from the steady state contingency analysis of the Phase 2a and 2b models is included in Appendix C.

Further discussion of the constraints identified below will be included within section 8.0 “Conclusion” along with the constraints identified in the other phases of this study.

Bus #	Bus Name	kV	System Intact Voltage w/o BSP II [%]	System Intact Voltage with BSP II [%]	Worst Contigency (causing lowest voltage)	Post cont. w/o BSP II [%]	Post cont. with BSP II [%]	Worst change in voltage [%]	Note
62005	Kerkhoven Tap	115	98.30	97.86	63050 WILLMAR4 230 66550 GRANITF4 230 1	92.73	90.73	-2.00	
62425	Willmar	115	96.90	96.28	63050 WILLMAR4 230 66550 GRANITF4 230 1	89.95	87.59	-2.36	
62756	Leven	69	94.88	95.86	63219 GRANTCO7 115 63220 ELBOWLK7 115 1	92.45	91.42	-1.03	1
62757	Glenwood	69	94.49	95.70	63219 GRANTCO7 115 63220 ELBOWLK7 115 1	92.77	91.75	-1.02	1
60746	Glenwood	69	94.45	95.58	63219 GRANTCO7 115 63220 ELBOWLK7 115 1	92.39	91.35	-1.04	1
60747	Villard	69	95.57	96.37	63219 GRANTCO7 115 63220 ELBOWLK7 115 1	92.67	91.66	-1.01	1
61784	Int'l Falls	118	104.43	104.42	61751 LITLFRK7 118 66753 RUNNING4 230 1	104.05	105.15	1.10	

[1] Greater Alexandria Area Low voltage issue currently under investigation and likely that MRES proposed system additions will mitigate low voltage issues.

Table 6-11 Summary of Phase 2a Steady State Voltage Concerns for Alternative 1 – without IS Partial Path Requests

This same contingency analysis was performed on the Phase 2b cases to determine if new steady state voltage concerns were present with the IS partial paths. This analysis monitored both MISO and MAPP facilities, but only focused on any new voltage violations that would have occurred on the MAPP system. There were no new voltage violations or pre-existing voltage violations aggravated by more than 1% during analysis of the IS partial path case.

For the detailed voltage results from contingency analysis of the Phase 2b case, refer to Appendix C.

6.2.2.3 Loss Analysis

Balancing area losses were calculated for the MAPP region along with ALTW to determine how losses are impacted by BSP II with alternative 1 in the Phase 2a and 2b models. The results in Table 6-12 include results for the Phase 2a case and indicate that the largest loss impacts occur in the XEL and OTP balancing areas. The new 230 kV transmission lines included as part of the Big Stone II project were modeled as being a part of the OTP balancing area.

Balancing Area	Load (MW)	Base	Alt #1	Δ MW
Area 331 (ALTW)	4612.6	119.7	121.7	2.0
Area 600 (XEL)	10833.2	467.1	485.2	18.1
Area 608 (MP)	1686.7	121.1	120.7	-0.4
Area 613 (SMMPA)	330	1.0	1.0	0.0
Area 618 (GRE)	1637	114.6	119.3	4.7
Area 626 (OTP)	1826	84.8	99.2	14.4
Area 633 (MPW)	174.2	1.5	1.5	0.0
Area 635 (MEC)	5730.4	142.9	144.8	1.9
Area 640 (NPPD)	3231.4	112.4	111.7	-0.7
Area 645 (OPPD)	2632.9	27.8	27.5	-0.3
Area 650 (LES)	836	9.8	9.8	0.0
Area 652 (WAPA)	3087.5	211.1	215.0	3.9
Area 667 (MH)	2964	298.9	298.6	-0.3
Area 680 (DPC)	972.2	76.2	75.3	-0.9
Total =	**40554.1**	**1788.9**	**1831.3**	**42.4**

Table 6-12 Losses (in MW) from Phase 2a Model for Alternative 1

Analysis of the Phase 2b models indicated that the incremental system losses did increase as a result of the IS partial paths. The specific loss values by balancing area for the Phase 2b case are shown in Table 6-13 and indicate that the largest loss increases occur in the XEL and OTP balancing areas. As mentioned previously, the new transmission lines included as part of alternative 1 were modeled as being a part of the OTP balancing area.

Balancing Area	Load (MW)	Base	Alt #1	△ MW
Area 331 (ALTW)	4612.6	126.7	129.2	2.5
Area 600 (XEL)	10833.2	493.1	515.2	22.1
Area 608 (MP)	1686.7	121.8	122.2	0.4
Area 613 (SMMPA)	330	1.0	1.0	0.0
Area 618 (GRE)	1637	117.2	122.8	5.6
Area 626 (OTP)	1826	90.7	105.3	14.6
Area 633 (MPW)	174.2	1.6	1.6	0.0
Area 635 (MEC)	5730.4	149.0	151.1	2.1
Area 640 (NPPD)	3231.4	111.6	111.3	-0.3
Area 645 (OPPD)	2632.9	27.5	27.3	-0.2
Area 650 (LES)	836	9.8	9.8	0.0
Area 652 (WAPA)	3087.5	229.5	233.4	3.9
Area 667 (MH)	2964	297.4	297.1	-0.3
Area 680 (DPC)	972.2	76.3	75.5	-0.8
Total =	**40554.1**	**1853.2**	**1902.8**	**49.6**

Table 6-13 Losses (in MW) from Phase 2b Model for Alternative 1

6.2.3 Analysis Results of Big Stone II with Transmission Alternative 2

This section of the report will include only a portion of the full results obtained from the steady state contingency analysis. This portion will focus only the outstanding violations for alternative 2 that are classified as a SAF based upon the criteria identified within section 4.2. The only difference between this section and the previous section is the facilities assumed to exist with Big Stone II. This section will only focus on the results obtained from the steady state simulations with alternative 2 versus the previous section, which focused on alternative 1. Sink definitions, dispatches and all other aspects of the alternative 1 cases remained the same for alternative 2.

Automap diagrams obtained for the existing system, alternative 1, and alternative 2 are included within Appendix A.

6.2.3.1 Thermal Constraints

Steady state contingency analysis of alternative 2 was also performed on the Phase 2 models to determine any thermal impacts on the transmission system. A summary of the results are shown below in Table 6-14. Similar to what was identified for alternative 2 during the Phase 1 analysis, quite a few 69 kV lines in the Willmar and Paynesville areas were identified as being significantly impacted by the addition of alternative 2 with Big Stone II. The Phase 2 models did not include GRE's proposed Kandiyohi 230/69 kV substation between Willmar and Paynesville, which will help unload the 69 kV systems out of these two existing substations. Phase 3 and 4 analysis did include this proposed substation and many of these same 69 kV facilities were not impacted which suggests that the proposed Kandiyohi substation will likely alleviate these issues from the Phase 2 analysis.

Similar to the thermal results from Phase 2 for alternative 1, some constraints found during this analysis appear to be facilities that have been identified by previous transmission service request studies being performed. As mentioned before, the proper coordination with MAPP/MISO will be necessary to determine which of the SAF identified below in Table 6-14 are truly the responsibility of Big Stone II.

The analysis of the Phase 2b models with the IS partial paths indicated that an additional 5 facilities are identified as compared to the Phase 2a models for alternative 2. Of these facilities, only one of these is a MAPP facility which is believed to be alleviated through a local protection scheme. The remaining MISO facilities that only appeared during the Phase 2b analysis are not required upgrades for Big Stone II since MISO transmission service requests for these IS partial path reservations are queued later than Big Stone II or not queued at all on the MISO OASIS.

The table below is only a summary of the full contingency analysis results from the Phase 2 analysis. A full listing of the results from the analysis is within Appendix C.

Further discussion of the constraints identified below will be included within section 8.0 "Conclusion" along with the constraints identified in the other phases of this study.

Constraint Element	Contingency Example	Owner	Rate A	EM Rate	% DF High	Highest MVA Loading w/o IS	Highest MVA Loading w/ IS	Note
34006 LAKEFLD3 345 34007 LAKEFLD5 161 1	34006 LAKEFLD3 345 34007 LAKEFLD5 161 2	ALTW	335	335	4.95	399.97	396.06	
34006 LAKEFLD3 345 34007 LAKEFLD5 161 2	34006 LAKEFLD3 345 34007 LAKEFLD5 161 1	ALTW	335	335	4.95	399.97	396.06	
34007 LAKEFLD5 161 34008 FOX LK 5 161 1	34007 LAKEFLD5 161 34008 FOX LK 5 161 P2	ALTW	160	160	3.88	211.23	220.95	1
34008 FOX LK 5 161 34012 FOXLAKE869.0 1	34009 WINBAGO5 161 61932 RUTLAND5 161 1 SW 889	ALTW	74.7	74.7	3.21	80.44	81.84	
60133 SHEYNNE4 230 66435 FARGO 4 230 1	63369 JAMESTN3 345 66791 CENTER 3 345 1	XCEL	388	388	5.4	x	407.9	2
60148 MINVALY7 115 60149 MINVALT4 230 P6	60150 MNVLTAP4 230 66550 GRANITF4 230 1	XCEL	187	215	8.34	x	228.03	2
60150 MNVLTAP4 230 66550 GRANITF4 230 1	60356 PAYNES 4 230 63050 WILLMAR4 230 1	XCEL	388	427	21.06	410.1	455.43	2
60156 PYNSVIL7 115 60760 PAYNES 869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	XCEL	47	54	3.45	70.04	75.42	
60156 PYNSVIL7 115 60760 PAYNES 869.0 2	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	XCEL	47	54	3.41	69.3	74.62	
60742 PANTHER869.0 63054 PANTHER4 230 1	62980 MCLEOD 4 230 63054 PANTHER4 230 1	XCEL	70	87.5	3.83	98.6	109.26	
62427 WILLMAR869.0 62437 SVEATAP869.0 1	60150 MNVLTAP4 230 63054 PANTHER4 230 1	GRE	45.5	45.5	3.45	56.49	62.63	
62437 SVEATAP869.0 62438 LITCHTP869.0 1	60150 MNVLTAP4 230 63054 PANTHER4 230 1	GRE	36.2	36.2	3.47	52.83	58.92	
62427 WILLMAR869.0 63050 WILLMAR4 230 1	60356 PAYNES 4 230 63050 WILLMAR4 230 1	GRE	84	84	5.5	100.6	105.66	
60760 PAYNES 869.0 62835 ROSCOTP869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	XCEL	48	52.8	4.41	69.1	76.5	4
62835 ROSCOTP869.0 62837 MUNSNTP869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	XCEL	48	52.8	4.28	65.1	72.3	4
60710 FARM TP869.0 62837 MUNSNTP869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	XCEL	48	52.8	4.26	62	69.3	4
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63329 WAHPETN4 230 66754 MAPLE R4 230 1 SW 959	MRES/OTP	96	105	4.16	108.68	116.45	
63327 HANKSON4 230 63329 WAHPETN4 230 1	63369 JAMESTN3 345 66791 CENTER 3 345 1	OTP	320	352	8.6	X	354	2
66424 BELFELD3 345 67183 CHAR.CK3 345 1	Loss of both Leland Olds 345/230 kV Transformers	WAPA	239	263	2.68	X	239.9	3

[1] This overload is due to loss of parallel circuit and has been identified in previous studies. MISO is considering an operating procedure which would alleviate this overload.

[2] Only flagged for IS scenario, but MISO facility. Not a constraint that Big Stone II would have to mitigate.

[3] This facility exceeds the normal rating, but not the emergency rating. An operating procedure could be permissible to alleviate this overload.

[4] These facilities were identified within the BRIGO study and are likely to be mitigated through upgrades by Xcel Energy for Buffalo Ridge Wind.

Table 6-14 Summary of Phase 2 Steady State Thermal Issues for Alternative 2

6.2.3.2 Voltage Constraints

The voltage violations identified for alternative 2 during the Phase 2 analysis are very similar to what was identified for alternative 1. Similar voltage issues around Glenwood were present with the addition of Big Stone II and transmission alternative 2. The Glenwood area problems will likely be mitigated through a separate project MRES is developing outside of Big Stone II, but will remain on the list of issues for Big Stone II since they have not been tested and verified to be eliminated yet with additional sensitivity analysis of the Phase 2 cases (although they were tested and found effective for Phase 3 and 4).

A summary of the voltage issues for Phase 2a is included below in Table 6-15. A full listing of all the voltage violations encountered during the steady state contingency analysis can be located within Appendix C.

Further discussion of the constraints identified below will be included within section 8.0 "Conclusion" along with the constraints identified in the other phases of this study.

Bus #	Bus Name	kV	System Intact Voltage w/o BSP II [%]	System Intact Voltage with BSP II [%]	Worst Contigency (causing lowest voltage)	Post cont. w/o BSP II [%]	Post cont. with BSP II [%]	Worst change in voltage [%]	Note
60746	Glenwood	69	92.39	91.1	63219 GRANTCO7 115 63220 ELBOWLK7 115 1	92.39	91.10	-1.29	1
60747	Villard	69	92.67	91.44	63219 GRANTCO7 115 63220 ELBOWLK7 115 1	92.67	91.44	-1.23	1
62005	Kerkhoven Tap	115	92.73	90.73	63050 WILLMAR4 230 66550 GRANITF4 230 1	92.73	90.73	-2.00	
62425	Willmar	115	89.95	87.59	63050 WILLMAR4 230 66550 GRANITF4 230 1	89.95	87.59	-2.36	
62756	Leven	69	92.45	91.18	63219 GRANTCO7 115 63220 ELBOWLK7 115 1	92.45	91.18	-1.27	1
62757	Glenwood	69	92.77	91.51	63219 GRANTCO7 115 63220 ELBOWLK7 115 1	92.77	91.51	-1.26	1
63220	Elbow Lake	115	90.42	89.05	63219 GRANTCO7 115 66555 MORRIS 7 115 1 SW938	90.42	89.05	-1.37	1
61784	Int'l Falls	118	104.05	105.15	61751 LITLFRK7 118 66753 RUNNING4 230 1	104.05	105.15	1.10	

[1] Greater Alexandria Area Low voltage issue currently under investigation and likely that MRES proposed system additions will mitigate low voltage issues.

Table 6-15 Summary of Phase 2a Steady State Voltage Concerns for Alternative 2 – without IS Partial Path Requests

During steady state contingency analysis of the Phase 2b cases for alternative 2, no new MAPP non-MISO issues were observed. The rest of the new voltage issues for alternative 2 in the Phase 2b analysis occurred on MISO facilities.

For the detailed voltage results from contingency analysis of the Phase 2b case, refer to Appendix C.

6.2.3.3 Loss Analysis

Balancing area losses were calculated for the MAPP region along with ALTW to determine how losses are impacted by BSP II with alternative 2 in the Phase 2a and 2b models. The results in Table 6-16 include results for the Phase 2a case and indicate that the largest loss impacts occur in the XEL, GRE and OTP balancing areas. The new 230 kV transmission lines included as part of the Big Stone II project were modeled as being a part of the OTP balancing area. Overall, incremental system losses are higher as compared to alternative 1, which was discussed in section 6.2.2.3.

Balancing Area	Load (MW)	Base	Alt #2	Δ MW
Area 331 (ALTW)	4612.6	119.7	121.4	1.7
Area 600 (XEL)	10833.2	467.1	486.0	18.9
Area 608 (MP)	1686.7	121.1	120.0	-1.1
Area 613 (SMMPA)	330	1.0	1.0	0.0
Area 618 (GRE)	1637	114.6	131.1	16.5
Area 626 (OTP)	1826	84.8	101.1	16.3
Area 633 (MPW)	174.2	1.5	1.5	0.0
Area 635 (MEC)	5730.4	142.9	144.5	1.6
Area 640 (NPPD)	3231.4	112.4	111.6	-0.8
Area 645 (OPPD)	2632.9	27.8	27.6	-0.2
Area 650 (LES)	836	9.8	9.8	0.0
Area 652 (WAPA)	3087.5	211.1	204.7	-6.4
Area 667 (MH)	2964	298.9	298.9	0.0
Area 680 (DPC)	972.2	76.2	75.4	-0.8
Total =	**40554.1**	**1788.9**	**1834.6**	**45.7**

Table 6-16 Losses (in MW) from Phase 2a Model for Alternative 2

Analysis of the Phase 2b models indicated that the incremental system losses did increase as a result of the IS partial paths. The specific loss values by balancing area for the Phase 2b case are shown in Table 6-17 and indicate that the largest loss increases occur in the XEL and OTP balancing areas. As mentioned previously, the new transmission lines included as part of alternative 2 were modeled as being a part of the OTP balancing area. Again, it is apparent that the incremental system losses are lower for alternative 1 versus alternative 2.

Balancing Area	Load (MW)	Base	Alt #2	△ MW
Area 331 (ALTW)	4612.6	126.7	128.9	2.2
Area 600 (XEL)	10833.2	493.1	516.7	23.6
Area 608 (MP)	1686.7	121.8	121.2	-0.6
Area 613 (SMMPA)	330	1.0	1.0	0.0
Area 618 (GRE)	1637	117.2	135.8	18.6
Area 626 (OTP)	1826	90.7	106.9	16.2
Area 633 (MPW)	174.2	1.6	1.6	0.0
Area 635 (MEC)	5730.4	149.0	150.8	1.8
Area 640 (NPPD)	3231.4	111.6	111.2	-0.4
Area 645 (OPPD)	2632.9	27.5	27.3	-0.2
Area 650 (LES)	836	9.8	9.8	0.0
Area 652 (WAPA)	3087.5	229.5	222.1	-7.4
Area 667 (MH)	2964	297.4	297.4	0.0
Area 680 (DPC)	972.2	76.3	75.5	-0.8
Total =	**40554.1**	**1853.2**	**1906.2**	**53.0**

Table 6-17 Losses (in MW) from Phase 2b Model for Alternative 2

6.3 Phase 3a and 3b – 2014 Summer Peak Scenario

Phase 3 studied out year summer peak conditions utilizing a powerflow model based on the NERC 2004 series 2014 summer peak model. The results indicate numerous potential system violations that pre-existed in the base case, and are not caused by the Big Stone II project, but presumably by prior queued projects and an additional 5 years of load growth as compared to the powerflow models for Phases 1 and 2.

The following general conditions were studied for Phase 3:

- Transmission Alternatives:
  - Alternative 1: Big Stone – Johnson Jct. – Morris 230 kV and Big Stone – Canby – Granite Falls 230 kV
  - Alternative 2: Big Stone – Willmar 230 kV and Big Stone – Canby – Granite Falls 230 kV
- Requests:
  - Confirmed transmission service requests in MISO and WAPA/IS queue
  - Prior “full path” transmission service requests in MISO and WAPA/IS queue
  - Prior queued partial path requests in the WAPA/IS queue

6.3.1 Model Assumptions Specific for Phase 3

6.3.1.1 Dispatch Assumptions

Big Stone II was turned online at 600 MW net, and sunk as shown in Table 6-18 below. Note that Big Stone I is the swing machine for the OTP balancing area. In order to fix this unit at maximum output, the Coyote unit was adjusted such that it was the de facto swing machine for the OTP balancing area. Big Stone I and Big Stone II will be connected to the same point in the grid, and hence for this study it is important that the existing unit be maximized.

Company	Unit Name	Bus #	MW
CMMPA			
	New Ulm	60939	7.4
	Blue Earth	60651	8.2
	Lake Crystal	60700	5.8
	Sleepy Eye	60722	8.6
	Sub Total		*30*
GRE			
	St.Boni	63021	62
	Pleasant Valley	63006	54
	Sub Total		*116*
HCPD			
	Cooper Nuc. Station	64709	25
	Sub Total		*25*
MDU			
	Miles City	66219	15.5
	Glendive	67332	32.5
	Heskett	67345	68
	Sub Total		*116*
MRES			
	Exira #1	67465	35.75
	Exira #2	67468	35.75
	Watertown	67451	38.5
	Sub Total		*110*
OTP			
	Solway	63285	50
	Jamestown Peaking	63172	44.6
	Coyote	67315	21.4
	Sub Total		*116*
HUC			
	Hutchinson	62985	40
	Sub Total		*40*
SMMPA			
	Fairmont	61936	34.9
	Austin	61985	12.1
	Sub Total		*47*
	GRAND TOTAL		**600.00**

Table 6-18 Generation Redispatch Assumptions for Phase 3

6.3.1.2 Topology Assumptions

Early in the project an additional substation connected to the Big Stone – Johnson Jct. – Morris 230 kV line was assumed at Ortonville, MN. The powerflow models assuming Transmission alternative 1 does show an Ortonville 230 kV bus. For this analysis though the 230/115 kV transformer was normally opened. Beyond this, no special topology assumptions were made fundamentally different from the assumptions made in the Phase 1 and 2 model, besides what differences occurred upon finalization of the MAPP 2004 series models. For more detailed model assumptions, please see section 5.0, "Model Development."

6.3.2 Analysis Results of BSP II with Transmission Alternative 1

Only excerpts from all of the data obtained in the simulations are listed in this section of the report. For detailed tables, consult Appendix C. For Automap diagrams from PSS/E reference Appendix A.

6.3.2.1 Thermal Constraints

Table 6-19 on the following page shows a summary of all thermal constraints seen in this part of the analysis for both the scenario without IS partial path requests and the scenario with IS partial path requests. One additional MISO facility is observed to be overloaded in the scenario with the IS partial path requests, as compared to the scenario without the IS partial path requests. Since the IS partial path scenario is not looking at MISO facilities (because necessary MISO transmission service requests are either queued later than BSP II, or not queued at all on the MISO OASIS), the list of constraints are in effect the same for both scenarios, although the flows are different.

Some of these listed constraints are known issues from other studies done for transmission service requests. It would seem numerous of these constraints could be highly dependent by the way the generation is sunk, and not by the Big Stone II project itself. Further sensitivity analysis might be warranted to investigate this before further facility studies are started.

Appendix C shows detailed results for the thermal analysis performed. The thermal constraints viewed as constraints for Big Stone II are discussed in general in section 8.0. As will be seen in section 6.3.3, transmission alternatives 1 and 2 scenarios see many of the same constraints.

Note that some MAPP elements listed are only in violation of the normal rating for the facility, and not in violation of the emergency rating. Such instances might be acceptable assuming that an acceptable operating scheme can be implemented to bring the loading on the facility below or at its normal rating within the maximum allowable time frame of the emergency rating (30 minutes).

Further discussion of the constraints identified below will be included within section 8.0 "Conclusion" along with the constraints identified in the other phases of this study.

						High MVA Loading		
Constraint Element	Contingency example	Owner	Rate A	EM Rate	%DF high	w/o IS	w/ IS	Note
34006 LAKEFLD3 345 34007 LAKEFLD5 161 1	60108 WILMARTH3 345 60331 LKFLDXL3 345 1	ALTW	335	335	5.34	382.18	394.2	
34006 LAKEFLD3 345 34007 LAKEFLD5 161 2	60108 WILMARTH3 345 60331 LKFLDXL3 345 1	ALTW	335	335	5.34	382.18	394.2	
34007 LAKEFLD5 161 34008 FOX LK 5 161 1	34007 LAKEFLD5 161 34008 FOX LK 5 161 P2	ALTW	160	160	4.35	204.75	210.8	
34008 FOX LK 5 161 34012 FOXLAKE869.0 1	61932 RUTLAND5 161 61934 RUTLAND 69.0 1	ALTW	74.7	74.7	4.39	94.96	99.28	
60133 SHEYENNE4 230 664356 FARGO 230 1	63369 JAMESTN3 345 66791 CENTER 3 345 1	WAPA	387	426	9.48	424.2	433.6	
60150 MNVLTAP4 230 66550 GRANITF4 230 1	63050 WILLMAR4 230 66550 GRANITF4 230 1	WAPA	387	426	19.52	398.69	425.39	
60884 YNGAMER869.0 60931 CARVRCO869.0 1	60277 WWACNIA7 115 62667 ST BONI7 115 1 SW990	Xcel	47	51.7	5.77	49.96	56.04	
61934 RUTLAND 69.0 61942 10TH STR69.0 1	34008 FOX LK 5 161 34012 FOXLAKE869.0 1	SMMPA	36	36	3.93	42.15	41.57	
62427 WILLMAR869.0 63050 WILLMAR4 230 1	63050 WILLMAR4 230 63058 KANDYCO4 230 1	GRE	84	92.4	7.39	121.22	125.74	
62667 ST BONI7 115 63021 ST BONI869.0 1	60211 GLESNLK7 115 60887 GLESNLK869.0 1	GRE	70	87.5	9.27	113.64	114.32	
63219 GRANTCO7 115 63220 ELBOWLK7 115 1	61611 WINGRIV4 230 63052 INMAN 4 230 1 SW819	MRES/OTP	160	160	3.03	163.76	167.25	
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	WAPA	96	105	6.47	113.72	124.56	
63327 HANKSON4 230 63329 WAHPETN4 230 1	63337 JHNSNJT4 230 66554 MORRIS 4 230 1	OTP	320	352	20.29	349.1	361.76	
66203 FARGO 869.0 67000 MAPLE R869.0 1	60133 SHEYNNE4 230 66435 FARGO 4 230 1	MPC	62	68	2.88	79.22	81.18	
66426 BISMARK4 230 66427 BISMARK7 115 1	67342 HESKETT4 230 67343 HESKETT7 115 1	WAPA	100	125	5.29	141.03	141.14	
66426 BISMARK4 230 66427 BISMARK7 115 2	67342 HESKETT4 230 67343 HESKETT7 115 1	WAPA	100	125	4.69	135.6	135.7	
66554 MORRIS 4 230 66555 MORRIS 7 115 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1 SW937	WAPA	100	125	22.32	181.3	186	
67306 BISM DT7 115 67309 BISEXP 7 115 1	67342 HESKETT4 230 67343 HESKETT7 115 1	MDU	67.8	67.8	3.89	81.81	81.8	
67309 BISEXP 7 115 67329 ESTBMRK7 115 1	67342 HESKETT4 230 67343 HESKETT7 115 1	MDU	67.8	67.8	3.97	88.13	97.16	
67342 HESKETT4 230 67343 HESKETT7 115 1	66427 BISMARK7 115 67329 ESTBMRK7 115 1	MDU	100	125	10.54	185.12	185.22	
66424 BELFELD3 345 66425 BELFELD4 230 1	Both Leland Olds 345/230 xfmrs	BEPC	250	300	3.65	248.37	253.01	1
66424 BELFELD3 345 67183 CHAR.CK3 345 1	Both Leland Olds 345/230 xfmrs	BEPC	239	263	3.20	245.57	250.14	1

Note 1: Constraint is not above EM rating, and it would be permissible to mitigate via op-guide.

Table 6-19 Summary of Phase 3 Thermal Constraints for Alternative 1 with and without IS Partial Path Requests

6.3.2.2 Steady State Voltage Constraints

Numerous steady state bus voltage violations were observed for scenarios both with and without the IS partial path requests. Upon further investigation, it seemed many of the issues where more driven by the sink definition than by actually turning BSP II online. Detailed results of investigation can be found in Appendix C. In summary, the following general issues were seen:

- St. Bonifacius ("St. Boni") area (west of Twin Cities metro): Numerous 69 kV and 115 kV bus voltage issues were seen near the St. Boni area. GRE's St. Boni diesel generating station is connected to the St. Boni 69 kV bus. Additional sensitivity work showed that many of these bus voltage violations were driven by the contingencies simulated, and turning off what in these Phase 3 models seems to be necessary reactive support for the area. Adding Big Stone II alone does not significantly impact the bus voltages in this area. For the Phase 3 analysis, 62 MW of power was sunk to St. Boni from BSP II. Planning study efforts are underway to address future transmission needs west of the Twin Cities.
- Fairmont area (Southwest Minnesota): A few bus voltage violations were evident between Fox Lake and Rutland. SMMPA's Fairmont generation, which is connected to the 69 kV system, tying into the Fox Lake and Rutland 161/69 kV substations, absorbed 34.9 MW of generation from BSP II. Separate sensitivity work showed that the bus voltage violations are due to Fairmont generation being offline, and outages in the local area. BSP II does not otherwise significantly impact these bus voltages. Additional industrial load is anticipated in the area, which would require transmission upgrades that should address these bus voltage issues.
- New Ulm area: (South-central Minnesota): A few bus voltage violations were seen on the Fort Ridgely/New Ulm area 69 kV system for loss of the Fort Ridgely 161/69 kV transformer. New Ulm (7.4 MW) and Sleepy Eye generation (8.6 MW) were part of the sink definition for Phase 3 and ramping down this generation largely caused the low voltages observed in this area. Additional sensitivity analysis has, however, indicated that BSP II does significantly impact the bus voltages in this area regardless of generation sinks. Transmission studies are being performed for this area to address load serving issues as well as potential transmission service and generation outlet needs.
- Hutchinson area (Central Minnesota): Hutchinson generation was modeled as a sink for the 40 MW of power that Hutchinson will be receiving through MRES. Some bus voltages were in violation (too low) during system intact conditions and for the outage of the McLeod 230/115 kV transformer. Additional sensitivity analysis indicated that backing down the Hutchinson generation is the predominant reason for the bus voltage impact seen in the analysis. BSP II alone has less than a 1% impact on the bus voltage in the area.
- Blue Earth area (South-central Minnesota): Blue Earth peaking generation connected to the Blue Earth 161/69 kV substation via a normally operated radial operated 69 kV line was completely turned off (8.2 MW) when BSP II was added. The analysis indicated that the Blue Earth 69 kV voltage is in violation of steady

state voltage criteria. Further sensitivity analysis indicates that BSP II alone does not impact the Blue Earth 69 kV voltages significantly. The reduction in voltage is mostly due to turning off the generation.

- "Greater Alexandria area" (Central Minnesota): Numerous steady state bus voltage violations were observed in the Alexandria area spreading northwest towards Audubon, MN and southeast to the Douglas County 115/69 kV substation, and even further down the 69 kV system partially fed from the Douglas County substation. MRES currently is planning to upgrade the reactive support capacity for Alexandria Light and Power, an MRES member. This upgrade could consist of installing additional breakers to be able to operate the Alexandria 115 kV loop normally closed, and adding one or two 25 MVAr capacitor banks at the Alexandria Switching Station. Additional simulations were performed assuming the upgrades would be in place with two capacitor banks. As is demonstrated further in the appendices, this is shown to bring many bus voltages back within criteria, including 69 kV buses partially served from the Douglas County substation. It does not quite fix all of the voltage violations observed in the area though (nor is that the intent of the capacitor bank project). Additional reactive support would still be necessary in the Perham, Frazee, and Detroit Lakes areas to help steady state bus voltage issues. This might also be caused by the model issue in the Perham area mentioned earlier. This area should also be further reinforced by the proposed Fargo – Alexandria – St.Cloud – Monticello 345 kV line (part of the CapX 2020 effort). Future study work for BSP II will study the impact this line will have on this area of low voltage.

Table 6-20 below shows a summary of steady state voltages observed. This table only lists those bus voltage concerns found to be significantly impacted by the BSP II project. Bus voltages that are due to the sink generator definition or that will be mitigated by the proposed Alexandria reactive capacity additions are not listed here, but can be found in Appendix C.

The same analysis was done with the IS partial path requests included in the case. The analysis of this case focused on MAPP non-MISO facilities, but also monitored MISO facilities. The greater Alexandria area low voltage issues were a little more severe in this case. Still the proposed breaker and capacitor bank addition in the Alexandria area sufficiently fixes all of the same issues, with the exception of one additional constraint. This scenario added the Detroit Lakes West bus to the list. Some additional MISO buses were also identified as possible issues in this case, but not in the case with only full path transmission service requests. For the detailed results, please see Appendix C.

Further discussion of the constraints identified below will be included within section 8.0 "Conclusion" along with the constraints identified in the other phases of this study.

Bus #	Bus Name	kV	System Intact Voltage w/o BSP II [%[	System Intact Voltage w/ BSP II [%]	Worst Contingency (causing lowest voltage on bus)	Post cont. w/o BSP II [%]	Post cont. w/ BSP II [%]	Worst change in voltage [%]
60720	New Ulm S	69	102.07	102.07	Fort Ridgely 115/69 kV	96.06	89.63	-6.45
60721	Essig	69	102.99	102.17	Fort Ridgely 115/69 kV	97.63	91.43	-6.20
60938	Fort Ridgley	69	103.46	103.27	Fort Ridgely 115/69 kV	96.85	90.62	-6.23
60939	New Ulm P	69	103.00	103.00	Fort Ridgely 115/69 kV	97.07	90.69	-6.38
60940	New Ulm T	69	103.40	103.11	Fort Ridgely 115/69 kV	96.75	90.49	-6.26
60941	New Ulm N	69	101.61	101.61	Fort Ridgely 115/69 kV	95.59	89.10	-6.49
62067	Searles Jct.	69	103.17	102.68	Fort Ridgely 115/69 kV	97.01	90.76	-6.25
62076	SCHLLNG	69	103.18	102.97	Fort Ridgely 115/69 kV	96.69	90.76	-6.15
62077	Schuler Tap	69	103.30	103.09	Fort Ridgely 115/69 kV	96.82	90.69	-6.13
62081	New Ulm	69	103.18	102.71	Fort Ridgely 115/69 kV	96.97	90.71	-6.26
62005	Kerkhoven Tap	115	99.18	98.78	Willmar – Granite Falls 230 kV	90.95	88.66	-2.29
62425	Willmar	115	98.92	98.52	Willmar – Granite Falls 230 kV	89.58	87.23	-2.35
62445	Four Corners	115	100.31	100.14	Arrowhead – 4 Corners 115 kV	88.85	86.42	-2.43
62530	Frazee	115	98.68	98.04	Audubon 230/115 kV xfmr	90.88	89.8	-1.08
63235	Perham	115	97.75	97.12	Frazee – Perham 115 kV	94.41	93.39	-1.02
67462	Detroit Lakes	115	99.56	98.97	Audubon 230/115 kV xfmr	91.39	90.35	-1.04
67463	Detroit Lakes	115	99.55	98.96	Audubon 230/115 kV xfmr	91.37	90.33	-1.04

Table 6-20 Summary of Phase 3a Steady State Voltage Concerns for Alternative 1 – without IS Partial Path Requests

6.3.2.3 Loss Analysis

Balancing area losses for the Phase 3a models are within Table 6-21 for alternative 1.

Balancing Area	Load (MW)	Base	Alt #1	△ MW
Area 331 (ALTW)	5171.4	137.1	139.5	2.4
Area 600 (XEL)	11804.3	471.5	487.1	15.6
Area 608 (MP)	1758.2	132.8	132.3	-0.5
Area 613 (SMMPA)	374.3	1.2	1.2	0.0
Area 618 (GRE)	1890.2	128.9	132.9	4.0
Area 626 (OTP)	1921.8	98.6	111.5	12.9
Area 633 (MPW)	174.5	1.9	1.9	0.0
Area 635 (MEC)	6207.2	144.4	147	2.6
Area 640 (NPPD)	3474.5	118.3	118	-0.3
Area 645 (OPPD)	2880.8	31.2	30.9	-0.3
Area 650 (LES)	918.6	11.9	11.9	0.0
Area 652 (WAPA)	3140.9	222.3	225.8	3.5
Area 667 (MH)	3176.9	242.8	242.5	-0.3
Area 680 (DPC)	1028.8	77.7	77	-0.7
Total =	**43922.4**	**1820.6**	**1859.5**	**38.9**

Table 6-21 Losses (in MW) from Phase 3a Model for Alternative 1

Analysis of the Phase 3b models indicated that the incremental system losses did increase as a result of the IS partial paths. The specific loss values by balancing area for the Phase 3b case are shown in Table 6-22.

Balancing Area	Load (MW)	Base	Alt #1	△ MW
Area 331 (ALTW)	5171.4	145.7	148.5	2.8
Area 600 (XEL)	11804.3	503.4	523	19.6
Area 608 (MP)	1758.2	134.5	134.6	0.1
Area 613 (SMMPA)	374.3	1.2	1.2	0.0
Area 618 (GRE)	1890.2	132.5	137.3	4.8
Area 626 (OTP)	1921.8	109.3	121.5	12.2
Area 633 (MPW)	174.5	2.1	2.1	0.0
Area 635 (MEC)	6207.2	151.1	153.9	2.8
Area 640 (NPPD)	3474.5	118.8	118.6	-0.2
Area 645 (OPPD)	2880.8	30.9	30.7	-0.2
Area 650 (LES)	918.6	11.9	11.9	0.0
Area 652 (WAPA)	3140.9	259.5	262.5	3.0
Area 667 (MH)	3176.9	240.7	240.4	-0.3
Area 680 (DPC)	1028.8	79	78.2	-0.8
Total =	**43922.4**	**1920.6**	**1964.4**	**43.8**

Table 6-22 Losses (in MW) from Phase 3b Model for Alternative 1

6.3.3 Analysis Results of BSP II with Transmission Alternative 2

Only excerpts from all of the data obtained in the simulations are listed in this section of the report. For more detailed tables, consult Appendix C. For Automap diagrams generated from PSS/E, reference Appendix A. The only difference between this case and the alternative 1 case is the assumed Big Stone II interconnection facilities. Sink definitions, dispatches, and all other aspects of this model remained the same as that of alternative 1.

6.3.3.1 Thermal Constraints

Table 6-23 on the following two pages shows a summary of all the thermal constraints identified in the analysis for this scenario. Three additional MISO facilities are observed as overloaded in the IS partial path scenario only. Only one additional WAPA facility, Granite Falls – Minnesota Valley Tap 230 kV, is shown as significantly impacted, and loaded above the normal rating, but below the emergency rating in the IS partial path scenario as compared to the full path transaction scenario.

Some of these listed constraints are known issues from other studies done for transmission service requests. It would seem that these constraints could be caused mostly by the way the generation is sunk and not by the Big Stone II project itself. Further sensitivity analysis might be warranted to investigate this before further facility studies are started.

Appendix C shows detailed results for the thermal analysis performed. The thermal constraints viewed as constraints for Big Stone II are discussed in general in section 8.0. Many of the same constraints were identified for alternatives 1 and 2.

Note that some MAPP elements listed are only in violation of the normal rating for the facility and not in violation of the emergency rating. Such instances might be acceptable assuming that an acceptable operating scheme can be implemented to bring the loading on the facility below it's normal rating within the maximum allowable time frame of the emergency rating (30 minutes).

Further discussion of the constraints identified below will be included within section 8.0 "Conclusion" along with the constraints identified in the other phases of this study.

Constraint Element	Contingency example	Owner	Rate A	EM Rate	%DF high	High MVA Loading w/o IS	High MVA Loading w/ IS	Note
34006 LAKEFLD3 345 34007 LAKEFLD5 161 1	60108 WILMARTH3 345 60331 LKFLDXL3 345 1	ALTW	335	335	5.34	380.46	393.61	
34006 LAKEFLD3 345 34007 LAKEFLD5 161 2	60108 WILMARTH3 345 60331 LKFLDXL3 345 1	ALTW	335	335	5.34	380.46	393.61	
34007 LAKEFLD5 161 34008 FOX LK 5 161 1	34007 LAKEFLD5 161 34008 FOX LK 5 161 P2	ALTW	160	160	4.35	204.2	210.42	
34008 FOX LK 5 161 34012 FOXLAKE869.0 1	61932 RUTLAND5 161 61934 RUTLAND 69.0 1	ALTW	74.7	74.7	4.39	93.97	97.61	
60133 SHEYENNE4 230 664356 FARGO 230 1	63369 JAMESTN3 345 66791 CENTER 3 345 1	WAPA	387	426	9.48	393.1	403.4	
60150 MNVLTAP4 230 66550 GRANITF4 230 1	63050 WILLMAR4 230 66550 GRANITF4 230 1	WAPA	387	426	19.52	x	406.09	2,3
60156 PYNSVIL7 115 60760 PAYNES 869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	Xcel	47	54	3.24	62.61	64.91	
60156 PYNSVIL7 115 60760 PAYNES 869.0 2	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	Xcel	47	54	3.21	61.95	64.23	
60710 FARM TP869.0 62837 MUNSNTP869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	Xcel	48	52.8	4.00	54.87	58.78	
60760 PAYNES 869.0 62835 ROSCOTP869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	Xcel	48	52.8	3.99	61.5	65.35	
60884 YNGAMER869.0 60931 CARVRCO869.0 1	60277 WWACNIA7 115 62667 ST BONI7 115 1 SW990	Xcel	47	51.7	5.77	56.2	56.11	
61934 RUTLAND 69.0 61942 10TH STR69.0 1	34008 FOX LK 5 161 34012 FOXLAKE869.0 1	SMMPA	36	36	3.93	42.17	41.5	
62003 JOHNJCT7 115 63216 ORTONVL7 115 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	MRES/OTP	96.6	106	3.35	122.75	124.65	
62003 JOHNJCT7 115 66555 MORRIS 7 115 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	GRE	98	108	3.34	108.18	110.31	
62427 WILLMAR869.0 62432 KANDYOH869.0 1	63050 WILLMAR4 230 63058 KANDYCO4 230 1	GRE	13.3	13.3	3.26	69.46	72.69	
62427 WILLMAR869.0 63050 WILLMAR4 230 1	63050 WILLMAR4 230 63058 KANDYCO4 230 1	GRE	84	92.4	7.39	146.44	151.07	
62432 KANDYOH869.0 62436 GREENLK869.0 1	63050 WILLMAR4 230 63058 KANDYCO4 230 1	GRE	13.3	13.3	3.27	58.35	61.44	
62667 ST BONI7 115 63021 ST BONI869.0 1	60211 GLESNLK7 115 60887 GLESNLK869.0 1	GRE	70	87.5	9.27	113.72	114.37	
62835 ROSCOTP869.0 62837 MUNSNTP869.0 1	60156 PYNSVIL7 115 60162 WAKEFLD7 115 P1	Xcel	48	52.8	3.99	58.4	62.26	
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	WAPA	96	105	6.47	107.42	111.77	
63327 HANKSON4 230 63329 WAHPETN4 230 1	63337 JHNSNJT4 230 66554 MORRIS 4 230 1	OTP	320	352	20.29	358.7	368.6	
66426 BISMARK4 230 66427 BISMARK7 115 1	67342 HESKETT4 230 67343 HESKETT7 115 1	WAPA	100	125	5.29	140.79	140.84	

66426 BISMARK4 230 66427 BISMARK7 115 2	67342 HESKETT4 230 67343 HESKETT7 115 1	WAPA	100	125	4.69	135.36	135.42	
67306 BISM DT7 115 67309 BISEXP 7 115 1	67342 HESKETT4 230 67343 HESKETT7 115 1	MDU	67.8	67.8	3.89	81.51	81.56	
67309 BISEXP 7 115 67329 ESTBMRK7 115 1	67342 HESKETT4 230 67343 HESKETT7 115 1	MDU	67.8	67.8	3.97	96.87	96.91	
67342 HESKETT4 230 67343 HESKETT7 115 1	66427 BISMARK7 115 67329 ESTBMRK7 115 1	MDU	100	125	10.54	185.27	185.27	
66424 BELFELD3 345 66425 BELFELD4 230 1	Both Leland Olds 345/230 xfmrs	BEPC	250	300	3.65	250.78	255.21	3
66424 BELFELD3 345 67183 CHAR.CK3 345 1	Both Leland Olds 345/230 xfmrs	BEPC	239	263	3.59	247.94	252.30	3

Note 1: Only flagged for IS scenario, but is a MISO facility. Not a constraint.
Note 2: Only flagged for IS scenario, and is a WAPA facility.
Note 3: Element's normal rating is violated, but not the emergency rating. Operating Procedure might be permissible for mitigation

Table 6-23 Summary of Phase 3 Thermal Constraints for Alternative 2 with and without IS Partial Path Request

6.3.3.2 Steady State Voltage Constraints

Numerous steady state bus voltage violations were observed for scenarios both with and without the IS partial path requests. Upon further investigation, it seemed many of the issues were more driven by the sink definition than by actually turning BSP II online. Detailed results of additional investigation can be found in Appendix G. Table 6-24 below shows a summary of the steady state voltage issues observed.

The summary table does not contain detailed listings of voltage issues sufficiently mitigated by an MRES proposal to add reactive support in the Alexandria area. This would address numerous voltage concerns flagged. Additional simulations were performed to check the impact of this proposed upgrade. For alternative 1, numerous sensitivity analyses were performed to look at the impact of ramping some of the individual generators down versus the bus voltages. Numerous situations were identified where it truly was the specific sink generator being ramped down or being turned off that caused the voltage violations, independent of Big Stone II being online or not. Since no topology differences between transmission alternative 1 and transmission alternative 2 are close to these voltage issues, no separate sensitivities have been run to verify the same is true for alternative 2. Data for the sensitivity analysis for voltages versus units being ramped down can be found in Appendix G.

Although the absolute values of system voltages are somewhat different in the scenario with the IS partial path requests, there are no additional MAPP non-MISO bus voltages shown as constraints, or not mitigated by the Alexandria reactive capacitor additions. Appendix C shows the voltage concerns with the IS partial path requests added to the model.

Further discussion of the constraints identified below will be included within section 8.0 “Conclusion” along with the constraints identified in the other phases of this study.

Bus #	Bus Name	kV	System Intact Voltage w/o BSP II [%[	System Intact Voltage w/ BSP II [%]	Worst Contingency (causing lowest voltage on bus)	Post cont. w/o BSP II [%]	Post cont. w/ BSP II [%]	Worst change in voltage [%]	Comment
60686	East Melrose	69	96.43	94.54	Douglas Co 115/69 kV	89.91	88.9	-1.02	Disconnects from benefit of Alex caps
60720	New Ulm S	69	102.07	102.07	Forth Ridgley 115/69 kV	96.08	90.26	-5.82	BSP II cause inc. imp.
60746	Glenwood	69	98.59	96.49	Douglas Co 115/69 kV	85.19	84.07	-1.09	Disconnect from benefit of Alex caps
60747	Villard	69	98.72	96.65	Douglas Co 115/69 kV	85.19	84.07	-1.13	"
60748	West Port	69	99.18	97.15	Douglas Co 115/69 kV	84.70	83.57	-1.14	"
60749	Douglas Co.	69	99.63	97.53	Douglas Co 115/69 kV	82.59	81.38	-1.14	"
60750	Osakis	69	99.31	97.22	Douglas Co 115/69 kV	82.60	81.44	-1.17	"
60751	Sauk Center	69	95.28	93.32	Douglas Co 115/69 kV	85.14	84.02	-1.13	"
60752	Black Oak	69	96.36	94.41	Douglas Co 115/69 kV	88.65	87.60	-1.13	"
60753	MEIRGRV	69	97.10	95.11	Douglas Co 115/69 kV	88.65	87.60	-1.05	"
60754	Melrose Mun	69	96.42	94.51	Douglas Co 115/69 kV	90.10	89.04	-1.07	"
60768	Elrosa Tap	69	98.30	96.30	Douglas Co 115/69 kV	92.32	91.31	-1.03	"
60938	Fort Ridgley	69	103.46	103.18	Forth Ridgley 115/69 kV	96.85	91.24	-5.61	BSP II cause inc. imp.
60939	New Ulm P	69	103.00	103.00	Forth Ridgley 115/69 kV	97.07	91.32	-5.75	"
60940	New Ulm T	69	103.40	103.02	Forth Ridgley 115/69 kV	96.75	91.13	-5.62	"
60941	New Ulm N	69	101.61	101.61	Forth Ridgley 115/69 kV	95.59	89.74	-5.85	"
62067	Searles Jct	69	103.17	102.58	Forth Ridgley 115/69 kV	97.01	91.42	-5.59	"
62076	SCHLLNG	69	103.18	102.87	Forth Ridgley 115/69 kV	96.69	91.16	-5.53	"
62077	SCHLTP	69	103.30	103.00	Forth Ridgley 115/69 kV	96.82	91.30	-5.52	"
62081	New Ulm	69	103.18	102.61	Forth Ridgley 115/69 kV	96.97	91.37	-5.60	"
62445	Four Corners	115	100.31	100.15	Arrowhead – 4 Corners 115 kV	88.85	86.36	-2.49	"
62530	Frazee	115	98.68	97.85	Audubon 230/115 kVxfmr	90.88	89.66	-1.22	
62755	Omen	69	99.31	97.27	Douglas Co 115/69 kV	84.79	83.66	-1.14	Disconnect from benefit of Alex caps
62756	Leven	69	98.58	96.49	Douglas Co 115/69 kV	86.06	84.95	-1.14	"
62757	Glenwood	69	99.09	97.05	Douglas Co 115/69 kV	88.30	87.25	-1.06	"
62820	West Union	69	97.45	96.20	Douglas Co 115/69 kV	83.39	82.25	-1.15	"
62821	Kandota	69	95.1	93.14	Douglas Co 115/69 kV	85.29	84.17	-1.13	"
62822	Kandota Tap	69	95.36	93.42	Douglas Co 115/69 kV	85.59	84.47	-1.13	"
62823	Elrosa	69	97.83	95.82	Douglas Co 115/69 kV	91.82	90.80	-1.13	"
62847	Grove	69	96.32	94.37	Douglas Co 115/69 kV	88.52	87.47	-1.06	"
63235	Perham	115	97.75	96.94	Frazee – Perham 115 kV	84.41	83.38	-1.18	"
67462	Detroit Lakes	115	99.56	98.77	Audubon 230/115 kV xfmr	91.39	90.19	-1.2	
67463	Detroit Lakes	115	99.55	98.76	Audubon 230/115 kV xfmr	91.37	90.18	-1.19	
67464	Detroit Lakes	115	99.85	99.07	Audubon 230/115 kV xfmr	91.60	90.42	-1.18	

Table 6-24 Summary of Phase 3a Steady State Voltage Concerns for Alternative 2 – without IS Partial Path Requests

6.3.3.3 Loss Analysis

Balancing area losses for the Phase 3a models are within Table 6-25 for alternative 2. Referring back to section 6.3.2.3, it is evident that alternative 1 has lower incremental system losses than alternative 2.

Balancing Area	Load (MW)	Base	Alt #2	△ MW
Area 331 (ALTW)	5171.4	137.1	139.3	2.2
Area 600 (XEL)	11804.3	471.5	487.9	16.4
Area 608 (MP)	1758.2	132.8	131.9	-0.9
Area 613 (SMMPA)	374.3	1.2	1.2	0.0
Area 618 (GRE)	1890.2	128.9	145.3	16.4
Area 626 (OTP)	1921.8	98.6	114.5	15.9
Area 633 (MPW)	174.5	1.9	1.9	0.0
Area 635 (MEC)	6207.2	144.4	146.7	2.3
Area 640 (NPPD)	3474.5	118.3	117.9	-0.4
Area 645 (OPPD)	2880.8	31.2	30.9	-0.3
Area 650 (LES)	918.6	11.9	11.9	0.0
Area 652 (WAPA)	3140.9	222.3	215.5	-6.8
Area 667 (MH)	3176.9	242.8	242.9	0.1
Area 680 (DPC)	1028.8	77.7	77	-0.7
Total =	**43922.4**	**1820.6**	**1864.8**	**44.2**

Table 6-25 Losses (in MW) from Phase 3a Model for Alternative 2

Analysis of the Phase 3b models indicated that the incremental system losses did increase as a result of the IS partial paths. The specific loss values by balancing area for the Phase 3b case are shown in Table 6-26. Alternative 2 losses are again incrementally higher than what was noted for the same Phase 3b case with alternative 1.

Balancing Area	Load (MW)	Base	Alt #2	△ MW
Area 331 (ALTW)	5171.4	145.7	148.2	2.5
Area 600 (XEL)	11804.3	503.4	524.6	21.2
Area 608 (MP)	1758.2	134.5	133.8	-0.7
Area 613 (SMMPA)	374.3	1.2	1.2	0.0
Area 618 (GRE)	1890.2	132.5	151.8	19.3
Area 626 (OTP)	1921.8	109.3	123.4	14.1
Area 633 (MPW)	174.5	2.1	2.1	0.0
Area 635 (MEC)	6207.2	151.1	153.5	2.4
Area 640 (NPPD)	3474.5	118.8	118.5	-0.3
Area 645 (OPPD)	2880.8	30.9	30.7	-0.2
Area 650 (LES)	918.6	11.9	11.9	0.0
Area 652 (WAPA)	3140.9	259.5	250.6	-8.9
Area 667 (MH)	3176.9	240.7	240.8	0.1
Area 680 (DPC)	1028.8	79	78.4	-0.6
Total =	**43922.4**	**1920.6**	**1969.5**	**48.9**

Table 6-26 Losses (in MW) from Phase 3b Model for Alternative 2

6.4 Phase 4a and 4b – Winter Peak Scenario

Phase 4 studied winter peak conditions with a high export level from the U.S. to Manitoba. After a lengthy initial discussion with MISO, the export level settled on was 700 MW. The model was based on a NERC 2004 series 2011 winter peak model.

Both transmission alternatives 1 and 2 were studied. Additional scenarios were added to study the non-MISO system with the WAPA/IS partial path requests included in the powerflow model.

Many of the constraints identified in the winter peak studies were also identified in summer peak studies. The general flow biases are quite different though and some unique winter peak constraints were found

6.4.1 Model Assumptions Specific for Phase 4

6.4.1.1 Dispatch Assumptions

Table 6-27 shows the exact dispatch assumptions made when turning Big Stone II online at 600 MW net, and sinking it to generation. Note that Big Stone I is the swing machine for the OTP balancing area in the model. In order to fix this unit at maximum output, Coyote was adjusted such that it was the de facto swing machine for the OTP balancing area.

Company	Unit Name	Bus #	MW
CMMPA			
	New Ulm	60939	2.5
	NSP System Pkrs		27.5
	Sub Total		30
GRE			
	PVS	63006	116
	Sub Total		116
HCPD			
	Cooper	64709	25
	Sub Total		25
MDU			
	Miles City	66219	22.4
	Glendive	67332	14.5
	Heskett	67345	60
	Lewis & Clark	67355	19.1
	Sub Total		116
MRES			
	Exira #1	67465	45
	Exira #2	67468	40.9
	Exira #3	67469	24.1
	Sub Total		110
OTP			
	Solway	63285	50
	Jamestown Peaking	63172	57.6
	Coyote	67315	8.4
	Sub Total		116
HUC			
	Hutchinson	62985	40
	Sub Total		40
SMMPA			
	Fairmont	61936	34.9
	Austin	61985	12.1
	Sub Total		47
	GRAND TOTAL		**600**

Table 6-27 Phase 4 Sinks

6.4.1.2 Topology Assumptions

As this phase of the study was performed later than the previous three phases, some more detail was known on the parameters of the Big Stone II interconnection facilities. More detail on this can be found in section 5.0 "Model Development." The winter peak base case has overall the same topology as the Phase 3 2014 summer peak case.

6.4.2 Analysis Results of BSP II with Transmission Alternative 1

This section discusses and summarizes the results found from the comparative contingency analysis performed on models assuming that the project would build transmission alternative 1. The tables within this section are only summaries/ examples of what was observed during the analysis. For the complete set of results, please see the appendices. References to the relevant appendices will be made throughout the text. Automaps from PSS/E can be found in Appendix A.

6.4.2.1 Thermal Constraints

Table 6-28 on the following page shows a summary of thermal overloads caused by or further aggravated by Big Stone II. The table summarizes the findings from both the scenario without the IS partial path requests and the scenario with the IS partial path requests.

Some of issues in this table are known elements from the previous phases of the Big Stone II studies and from other transmission service studies. As to be expected, some unique issues were found as well. This is not surprising with the quite different system bias in the winter peak case compared to the summer peak cases. It would seem numerous of these constraints could be caused mostly by the way the generation is sunk, and not by the Big Stone II project itself. Further sensitivity analysis might be warranted to investigate this before further facility studies are started.

Appendix C shows the detailed results. Further discussion of the constraints identified below will be included within section 8.0 “Conclusion” along with the constraints identified in the other phases of this study.

Note that some MAPP elements listed are only in violation of the normal rating for the facility, and not in violation of the emergency rating. Such instances might be acceptable assuming that an acceptable operating scheme can be implemented to bring the loading of the facility below or at it’s normal rating within the maximum allowable time frame of the emergency rating.

						High MVA Loading		
Constraint Element	Contingency Example	Owner	Rate A	EM Rate	%DF High	w/o IS	w/IS	Note
61640 BADOURA7 115 - 66716 LAPORTE7 115 1	Wilton - Winger 230 kV	MPC	120	132	4.72	150.35	148.44	
66203 FARGO 869.0 - 67000 MAPLE R869.0 1	Sheyenne - Fargo 230 kV	MPC	72	80	3.06	86.26	87.41	
66435 FARGO 4 230 - 66553 MOORHED4 230 1	Big Stone - Browns Valley 230 kV	WAPA	239	263	21.90	241.9	246.17	1
66436 FARGO 7 115 - 66203 FARGO 8 69 2	Sheyenne - Fargo 230 kV	WAPA	100	125	2.44	126.96	128.29	
66437 GRNDFKS4 230 - 66759 PICKERT4 230 1	500 kV outage	WAPA	319	351	5.12	x	331	1
63219 GRANTCO7 115 - 66555 MORRIS 7 115 1	Johnson Jct - Graceville 115 kV	MRES/OTP	96	105	7.24	145	149.5	
63327 HANKSON3 230 - 63329 WAHPETN4 230 1	Wing River - Riverton 230 kV	OTP	320	352	21.21	455.05	466.88	
66444 JAMESTN4 230 - 66759 PICKERT4 230 1	500 kV outage	WAPA	319	351	5.12	x	350.6	1
62005 KERKHOT7 115 - 62006 KERKHO 7 115 1	Morris 230/115 kV xfmr SW930	GRE	44.82	44.82	6.03	64.09	65.84	
LELAND OLDS 345/230 kV XFMR #1	Leland Olds 345/230 kV xfmr #2	BEPC	500	600	4.37	673.5	832.43	
LELAND OLDS 345/230 kV XFMR #2	Antelope Valley – Charlie Crk. 345 kV	BEPC	250	300	2.30	312.06	318.20	
66553 MOORHED4 230 - 66554 MORRIS 4 230 1	System Intact	WAPA	239	263	23.36	305.79	311.29	
66554 MORRIS 4 230 - 66555 MORRIS 7 115 1	Kerkhoven - Kerkhoven Tap 115	WAPA	100	125	25.23	168.1	172.97	
60116 PRASWCP7 115 - 66712 PRAIRIE7 115 1	500 kV outage	MPC	298	298	15.62	x	310.2	
60133 SHEYENNE4 230 - 66435 FARGO 230 1	Center - Jamestown 345 kV	WAPA	391	391	10.92	403.9	415.7	
66424 BELFELD3 345 66425 BELFELD4 230 1	Both Leland Olds 345/230 xfmrs	BEPC	250	300	3.51	325.85	331.79	
66424 BELFELD3 345 67183 CHAR.CK3 345 1	Both Leland Olds 345/230 xfmrs	BEPC	239	263	2.92	322.25	328.36	

Note 1: Element's normal rating is violated, but not the emergency rating. Operating Procedure might be permissible for mitigation.

Table 6-28 Summary of Phase 4 Thermal Constraints for Alternative 1 with and without IS Partial Path Requests

In the initial analysis, overloads were observed on the Moorhead 115 kV system due to the loss of the Fargo – Moorhead 230 kV line. With further review, this contingency should be modeled as an outage of the Fargo – Moorhead 230 kV line along with the outage of the two 230/115 kV transformers at Moorhead due to the breaker configuration. This causes Moorhead to be served radially from the Fargo 115 kV bus and thus eliminates the through-flow which causes the overloads on the Moorhead 115 kV system. The multiple element outage was performed to demonstrate this and also showed no additional constraints. The initial results flagging the Moorhead area 115 kV is listed in the appendices for Alternative 1 winter peak cases.

6.4.2.2 Steady State Voltage Constraints

Table 6-29 below shows a summary of the steady state voltage concerns found for this scenario. The full output can be seen in Appendix C.

Bus #	Bus Name	kV	System Intact Voltage w/o BSP II [%[	System Intact Voltage w/ BSP II [%]	Worst Contingency (causing lowest voltage on bus)	Post cont. w/o BSP II [%]	Post cont. w/ BSP II [%]	Worst change in voltage [%]
60719	Lafayette Tap	69	100.94	101.00	Fort Ridgley 115/69 kV	93.02	91.45	-1.57
60720	New Ulm S	69	101.61	101.53	Fort Ridgley 115/69 kV	87.08	84.13	-2.95
60721	Essig	69	101.76	102.00	Fort Ridgley 115/69 kV	90.76	88.73	-2.03
60938	Fort Ridgley	69	102.79	102.93	Fort Ridgley 115/69 kV	88.46	85.82	-2.64
60939	New Ulm P	69	102.15	102.07	Fort Ridgley 115/69 kV	87.71	84.78	-2.93
60940	New Ulm T	69	102.70	102.82	Fort Ridgley 115/69 kV	88.66	86.08	-2.58
60941	New Ulm N	69	101.35	101.27	Fort Ridgley 115/69 kV	86.78	83.82	-2.96
61649	Blanchard	115	100.31	99.90	Blanchard – Little Falls 115 kV	96.02	94.80	-1.22
62067	Searles Jct	69	102.29	102.46	Fort Ridgley 115/69 kV	89.43	87.05	-2.38
62076	SCHLLNG	69	102.56	102.70	Fort Ridgley 115/69 kV	88.58	86.01	-2.57
62077	SCHLTP	69	102.66	102.80	Fort Ridgley 115/69 kV	88.69	86.13	-2.56
62079	Lafayette T	69	101.09	101.16	Fort Ridgley 115/69 kV	92.52	90.85	-1.67
62080	Home Tap	69	101.25	101.55	Fort Ridgley 115/69 kV	92.07	90.37	-1.70
62081	New Ulm	69	102.33	102.49	Fort Ridgley 115/69 kV	89.34	86.94	-2.40
62082	Home	69	101.23	101.52	Fort Ridgley 115/69 kV	92.04	90.34	-1.70
63235	Perham	115	101.26	99.72	Frazee – Perham 115 kV	91.87	90.69	-1.18
63216	Ortonville	115	104.97	104.72	Highway 12 – Ortonville 115 kV	104.99	110.54	+5.55
63287	ORTQUAR	115	104.83	104.54	Highway 12 – Ortonville 115 kV	104.79	110.12	+5.33

Table 6-29 Summary of Phase 4a Steady State Voltage Concerns for Alternative 1 – without IS Partial Path Requests

Most of the voltage concerns shown here occur when the Fort Ridgley 115/69 kV transformer is out of service. This is likely coupled to New Ulm generation being part of the sink definition and the general load serving issues that can be observed in the New Ulm area when losing this transformer. The project impacts the Blanchard 115 kV by -1.22%. This barely brings the bus voltage below the 95% criteria Minnesota Power uses.

In addition Perham bus voltage is negatively impacted some by the project, but are not ideal to begin with. This might be due to the Perham model issue described earlier. Two high voltages concerns can be seen on two Ortonville area 115 kV buses. Voltages go slightly above the 110% maximum criteria, which is likely due to a 30 MVAr capacitor bank being locked at Ortonville.

No additional MAPP non-MISO bus voltage issues where seen in the scenario that also included the IS partial path requests. Appendix C shows the detailed results of the screening done on the cases that included the IS partial path requests.

Further discussion of the constraints identified below will be included within section 8.0 "Conclusion" along with the constraints identified in the other phases of this study.

6.4.2.3 Loss Analysis

Balancing area losses for the Phase 4a models are within Table 6-30 for alternative 1. Winter peak conditions exhibit less incremental system losses than any of the summer peak conditions studied previously in Phases 1 through 3.

Balancing Area	Load (MW)	Base	Alt #1	△ MW
Area 331 (ALTW)	3818.1	73	73	0.0
Area 600 (XEL)	8498.5	301.6	297.6	-4.0
Area 608 (MP)	1730.5	88.4	87.5	-0.9
Area 613 (SMMPA)	257.2	0.7	0.7	0.0
Area 618 (GRE)	1291.6	108	108.7	0.7
Area 626 (OTP)	2299.5	126.7	150.5	23.8
Area 633 (MPW)	142.8	0.3	0.3	0.0
Area 635 (MEC)	3985.6	95	98.4	3.4
Area 640 (NPPD)	2302.8	96.9	96.2	-0.7
Area 645 (OPPD)	1859	19.8	19.6	-0.2
Area 650 (LES)	551.1	5	4.9	-0.1
Area 652 (WAPA)	2842.1	221.4	225.3	3.9
Area 667 (MH)	3909	237.1	237	-0.1
Area 680 (DPC)	880.9	71.9	69.8	-2.1
Total =	**34368.7**	**1445.8**	**1469.5**	**23.7**

Table 6-30 Losses (in MW) from Phase 4a Model for Alternative 1

Analysis of the Phase 4b models indicated that the incremental system losses were actually slightly lower than without IS partial paths. The specific loss values by balancing area for the Phase 4b case are shown in Table 6-31.

Balancing Area	Load (MW)	Base	Alt #1	△ MW
Area 331 (ALTW)	3818.1	75	75.1	0.1
Area 600 (XEL)	8498.5	307.4	304.5	-2.9
Area 608 (MP)	1730.5	87.4	86.5	-0.9
Area 613 (SMMPA)	257.2	0.7	0.6	-0.1
Area 618 (GRE)	1291.6	108.3	109.2	0.9
Area 626 (OTP)	2299.5	131.6	153.5	21.9
Area 633 (MPW)	142.8	0.3	0.3	0.0
Area 635 (MEC)	3985.6	97	100.4	3.4
Area 640 (NPPD)	2302.8	96.6	96	-0.6
Area 645 (OPPD)	1859	19.7	19.5	-0.2
Area 650 (LES)	551.1	4.9	4.9	0.0
Area 652 (WAPA)	2842.1	229.1	233.3	4.2
Area 667 (MH)	3909	236.4	236	-0.4
Area 680 (DPC)	880.9	72.3	70.2	-2.1
Total =	**34368.7**	**1466.7**	**1490.0**	**23.3**

Table 6-31 Losses (in MW) from Phase 4b Model for Alternative 1

6.4.3 Analysis Results of BSP II with Transmission Alternative 2

This section discusses and summarizes the results found from the comparative contingency analysis performed on models assuming that the project would build transmission alternative 1. The tables shown in this section are only summaries of what was observed during the analysis. For the complete set of results, please see the appendices. References to the relevant appendices will be made throughout the text. Automaps from PSS/E can be found in Appendix A.

6.4.3.1 Thermal Constraints

Table 6-32 on the following page shows a summary of thermal overloads caused by or further aggravated by Big Stone II. The table summarizes the findings from both the scenario without the IS partial path requests, and the scenario with the IS partial path requests.

Some of issues in this table are known constraints from the previous phases of the Big Stone II studies and from other transmission service studies. As to be expected, some unique issues were found as well. This is not surprising with the quite different system bias in the winter peak case compared to the summer peak cases. It would seem numerous of these constraints could be caused mostly by the way the generation is sunk, and not by the Big Stone II project itself. Further sensitivity analysis might be warranted to investigate this before further facility studies are started.

Appendix C shows the detailed results. Further discussion of the constraints identified below will be included within section 8.0 “Conclusion” along with the constraints identified in the other phases of this study.

Note that some MAPP elements in the following table are only in violation of the normal rating for the facility and not in violation of the emergency rating. Such instances might be acceptable assuming that an acceptable operating scheme can be implemented to bring the loading of the facility below or at it's normal rating within the maximum allowable time frame of the emergency rating.

Constraint Element	Contingency Example	Owner	Rate A	EM Rate	%DF High	High MVA Loading w/o IS	High MVA Loading w/IS	Note
61640 BADOURA7 115 - 66716 LAPORTE7 115 1	Wilton - Winger 230 kV	MPC	120	132	5.21	152.32	150.01	
63219 GRANTCO7 115 - 66555 MORRIS 7 115 1	Johnson Jct - Graceville 115 kV	MRES/OTP	96	105	5.11	132.3	136.6	
63327 HANKSON3 230 - 63329 WAHPETN4 230 1	Wing River - Riverton 230 kV	OTP	320	352	12.86	442.1	452.4	
62003 JOHNJCT7 115 - 66555 MORRIS 7 115 1	Canby - Granite Falls 230 kV	GRE/MRES	106	116.5	5.65	131.02	133.87	
62003 JOHNJCT7 115 - 63216 ORTONVL7 115 1	Canby - Granite Falls 230 kV	OTP/MRES	126.5	139.1	5.69	144.19	147	
LELAND OLDS 345/230 kV XFMR #1	Leland Olds 345/230 kV xfmr #2	BEPC	500	600	4.58	824.55	839.07	
LELAND OLDS 345/230 kV XFMR #2	Antelope Valley – Charlie Crk. 345 kV	BEPC	250	300	2.37	358.06	363.86	
66424 BELFELD3 345 66425 BELFELD4 230 1	Both Leland Olds 345/230 xfmrs	BEPC	250	300	3.52	323.11	329.20	
66424 BELFELD3 345 67183 CHAR.CK3 345 1	Both Leland Olds 345/230 xfmrs	BEPC	239	263	3.51	325.85	331.79	

Note 1: Element's normal rating is violated, but not the emergency rating. Operating Procedure might be permissible for mitigation.

Table 6-32 Summary of Phase 4 Thermal Constraints for Alternative 2 with and without IS Partial Path Requests

6.4.3.2 Steady State Voltage Constraints

Table 6-33 below shows a summary of the steady state voltage concerns found for alternative 2 during the Phase 4 analysis.. The full output can be found in Appendix C.

Bus #	Bus Name	KV	System Intact Voltage w/o BSP II [%[	System Intact Voltage w/ BSP II [%]	Worst Contingency (causing lowest voltage on bus)	Post cont. w/o BSP II [%]	Post cont. w/ BSP II [%]	Worst change in voltage [%]
60719	Lafayette Tap	69	100.94	100.92	Fort Ridgley 115/69 kV	93.02	91.72	-1.30
60720	New Ulm S	69	101.61	101.46	Fort Ridgley 115/69 kV	87.08	84.49	-2.59
60721	Essig	69	101.76	101.92	Fort Ridgley 115/69 kV	90.76	89.10	-1.66
60916	Garwind	69	99.16	99.17	Maple Leaf – Cascade 161 kV	97.21	93.50	-3.71
60938	Fort Ridgley	69	102.79	102.86	Fort Ridgley 115/69 kV	88.46	86.17	-2.29
60939	New Ulm P	69	102.15	102.00	Fort Ridgley 115/69 kV	87.71	85.13	-2.58
60940	New Ulm T	69	102.70	102.75	Fort Ridgley 115/69 kV	88.66	86.43	-2.23
60941	New Ulm N	69	101.35	101.20	Fort Ridgley 115/69 kV	86.78	84.17	-2.61
61649	Blanchard	115	100.31	99.67	Blanchard – Little Falls 115 kV	96.02	94.41	-1.61
62067	Searles Jct	69	102.29	102.39	Fort Ridgley 115/69 kV	89.43	87.41	-2.02
62076	SCHLLNG	69	102.56	102.63	Fort Ridgley 115/69 kV	88.58	86.35	-2.23
62077	SCHLTP	69	102.66	102.73	Fort Ridgley 115/69 kV	88.69	86.47	-2.22
62079	Lafayette T	69	101.09	101.08	Fort Ridgley 115/69 kV	92.52	91.13	-1.39
62080	Home Tap	69	101.25	101.48	Fort Ridgley 115/69 kV	92.07	90.75	-1.32
62081	New Ulm	69	102.33	102.42	Fort Ridgley 115/69 kV	89.34	87.30	-2.04
62082	Home	69	101.23	101.45	Fort Ridgley 115/69 kV	92.04	90.73	-1.31
63235	Perham	115	101.26	100.07	Frazee – Perham 115 kV	91.87	90.43	-1.44
66789	Bemidji	115	97.83	98.26	Wilton 230/115 kV xfmr	96.27	91.84	-4.43

Table 6-33 Summary of Phase 4a Steady State Voltage Concerns for Alternative 2 – without IS Partial Path Requests

These results are very similar to those observed for Alternative 1. In addition an issue is seen at the Garwind sub near Dodge Center, MN for loss of Maple Leaf – Cascade Creek 161 kV and on the Bemidji 115 kV bus for loss of the Wilton 230/115 kV transformer. No additional MAPP non-MISO issues were observed in the cases with the IS partial path requests included. The results from the steady state voltage analysis, which included the IS partial path requests, can be found in Appendix C.

Further discussion of the constraints identified below will be included within section 8.0 “Conclusion” along with the constraints identified in the other phases of this study.

6.4.3.3 Loss Analysis

Balancing area losses for the Phase 4a models are within Table 6-34 for alternative 2. Referring back to section 6.3.3.3, it is evident that again the Phase 4 model has lower overall system losses in the MAPP region. Comparing these alternative 2 loss values to section 6.4.2.3, it is evident that alternative 1 has lower incremental system losses than alternative 2.

Balancing Area	Load (MW)	Base	Alt #2	Δ MW
Area 331 (ALTW)	3818.1	73	73	0.0
Area 600 (XEL)	8498.5	301.6	298.9	-2.7
Area 608 (MP)	1730.5	88.4	88.1	-0.3
Area 613 (SMMPA)	257.2	0.7	0.7	0.0
Area 618 (GRE)	1291.6	108	114.7	6.7
Area 626 (OTP)	2299.5	126.7	159.7	33.0
Area 633 (MPW)	142.8	0.3	0.3	0.0
Area 635 (MEC)	3985.6	95	98.3	3.3
Area 640 (NPPD)	2302.8	96.9	96.2	-0.7
Area 645 (OPPD)	1859	19.8	19.6	-0.2
Area 650 (LES)	551.1	5	4.9	-0.1
Area 652 (WAPA)	2842.1	221.4	220.4	-1.0
Area 667 (MH)	3909	237.1	237.2	0.1
Area 680 (DPC)	880.9	71.9	69.9	-2.0
Total =	**34368.7**	**1445.8**	**1481.9**	**36.1**

Table 6-34 Losses (in MW) from Phase 4a Model for Alternative 2

Analysis of the Phase 4b models indicated that the incremental system losses did increase as a result of the IS partial paths. The specific loss values by balancing area for the Phase 3b case are shown in Table 6-35. Alternative 2 losses are again incrementally higher than what was noted for the same Phase 3b case with alternative 1.

Balancing Area	Load (MW)	Base	Alt #2	△ MW
Area 331 (ALTW)	3818.1	75	75.1	0.1
Area 600 (XEL)	8498.5	307.4	306.4	-1.0
Area 608 (MP)	1730.5	87.4	87.3	-0.1
Area 613 (SMMPA)	257.2	0.7	0.6	-0.1
Area 618 (GRE)	1291.6	108.3	115.7	7.4
Area 626 (OTP)	2299.5	131.6	163.9	32.3
Area 633 (MPW)	142.8	0.3	0.3	0.0
Area 635 (MEC)	3985.6	97	100.4	3.4
Area 640 (NPPD)	2302.8	96.6	95.9	-0.7
Area 645 (OPPD)	1859	19.7	19.5	-0.2
Area 650 (LES)	551.1	4.9	4.9	0.0
Area 652 (WAPA)	2842.1	229.1	227.9	-1.2
Area 667 (MH)	3909	236.4	236.4	0.0
Area 680 (DPC)	880.9	72.3	70.3	-2.0
Total =	**34368.7**	**1466.7**	**1504.6**	**37.9**

Table 6-35 Losses (in MW) from Phase 4b Model for Alternative 2

7.0 Phases 1-4 Flowgate Analysis

Flowgate analysis was performed for BSP II dispatched at 600 MW on both MAPP and MISO Flowgate lists. Appendix B contains the full results of the MAPP Flowgate analysis. The analysis on the MISO Flowgate list has not been finalized at the time this report was submitted to the DRS for review. This study used both the new list of MAPP Flowgates that is posted on the MAPP OASIS, which contains 134 flowgates and the traditional list of MAPP Flowgates that has been used in the past and is posted on the DRS page of the MAPP Extranet, which contains 35 flowgates. The DFCALC program was used to evaluate the MAPP list of Flowgates and MUST was used to evaluate the MISO Flowgates utilizing information provided by MISO for the flowgate definitions.

Table 7-1 below summarizes the MAPP PTDF and OTDF Flowgates which were impacted above the previously stated cut-offs for each phase of the analysis. The three flowgates that were impacted by BSP II are the Minnesota-Wisconsin Stability Interface (MWSI), the Prairie Island to Byron 345 kV line (PI-BY) and the North Dakota Export Interface (NDEX). The differences in DF impacts for the various phases are due to the different dispatches that were used for each phase and minor topology differences.

A new interface was created for NDEX called NDEX-BSP, which contains the new BSP II interconnection lines that cross the currently defined NDEX boundary. This was done for reference purposes. The current NDEX definition is altered due to the Canby-Granite Falls 115 kV line being upgraded to 230 kV and it thus, does not exist, and is not captured in the change case. The NDEX-BSP interface includes the Canby-Granite Falls 230 kV line for both alternatives and the Big Stone-Willmar 230 kV line for Alternative 2.

	Alternative 1				Alternative 2			
Phase	**PI-BY**	**MWSI**	**NDEX**	**NDEX-BSP**	**PI-BY**	**MWSI**	**NDEX**	**NDEX-BSP**
1	3.7%	4.6%	28.0%	65.0%	4.1%	5.1%	-3.5%	67.0%
2a	6.6%	7.8%	26.7%	65.0%	7.1%	8.5%	-5.4%	67.5%
2b	6.8%	8.2%	25.8%	65.3%	7.3%	8.8%	-7.1%	68.0%
3a	7.4%	8.3%	22.7%	61.3%	7.9%	9.0%	-9.2%	64.3%
3b	7.3%	8.1%	21.9%	61.2%	8.1%	9.4%	-10.3%	64.5%
4a	12.9%	14.1%	28.2%	59.0%	13.0%	14.3%	-0.9%	60.5%
4b	13.0%	14.2%	28.1%	59.2%	13.1%	14.5%	-2.1%	60.6%

Table 7-1 Summary of Flowgate Analysis

None of the impacted flowgates should be considered limiting for BSP II. There are several factors leading to this conclusion. First, the impacts on PI-BY and MWSI appear to be largely due to the BSP II dispatch sink of the Pleasant Valley Station (PVS). PVS is located on the 345 kV line just south of the Byron end of the flowgate. The increased DF impact on the two flowgates appears to be directly correlated to the amount of generation that is sunk to PVS. Second, the models include the Arrowhead – Stone Lake

– Gardner Park 345 kV line, which will change the definition of MWSI and likely PI-BY as well. Third, BSP II is building facilities that cross the NDEX boundary which will result in NDEX being redefined. Any limitations from the BSP II transfers due to the existing definitions of the stability interfaces would be shown in the stability analysis of regional disturbances in the interconnection study. If there are no limitations from the stability analysis, then one could argue that BSP II does not impact these stability interfaces. Lastly, none of these flowgates are loaded close to their thermal limits. Table 7-2 below summarizes the loadings on the significantly affected, but not overloaded flowgates.

	Alternative 1				Alternative 2			
Phase	PI-BY	MWSI	NDEX	NDEX-BSP	PI-BY	MWSI	NDEX	NDEX-BSP
1	49.2	516.8	911.3	1133.2	51.2	519.4	722.2	1145.0
2a	208.0	648.5	879.8	1109.6	210.9	652.8	687.1	1124.7
2b	160.0	575.7	974.8	1211.6	162.5	579.5	777.2	1228.0
3a	306.4	693.7	828.0	1060.2	309.1	697.8	636.8	1077.6
3b	296.2	660.5	821.0	1056.7	300.7	668.8	627.8	1076.8
4a	54.9	379.9	-84.8	100.0	55.9	381.4	-259.6	108.7
4b	28.1	340.3	-91.3	95.6	29.1	342.1	-272.4	103.8

Table 7-2 MW Loading on the Significantly Affected Flowgates

There was one OTDF flowgate that did not solve using the DFCALC program for any scenario. This was the Arnold – Hazelton 345 kV line for loss of Dorsey – Forbes 500 kV line. This outage was run by hand, and the DF on the flowgate was found to be less than 2%, and thus below the DF cutoff.

8.0 Conclusion

This section provides a summary of all the constraints observed in the various phases of the study. The first section summarizes results when considering transmission alternative 1 (230 kV from Big Stone – Johnson Jct. – Morris and 230 kV from Big Stone – Canby – Granite Falls), and the second section summarizes results when considering transmission alternative 2 (230 kV from Big Stone – Willmar and 230 kV from Big Stone – Canby – Granite Falls). The final section summarizes the results and discusses future study work to be completed.

At this time, there is not an identified fix for many of the issues identified. Many of the issues though are not unique for Big Stone II, and are being studied through other generation interconnection and transmission service studies, as well as load serving studies. It is anticipated that some issues shown in this report will be addressed through other projects. A couple of examples are MRES' plans to add reactive support in the Alexandria area and the outcome of transmission additions in ongoing load serving studies for southwestern Minnesota. As more details become available on plans to mitigate many of these concerns, analysis will be performed to make sure any such solutions also adequately address Big Stone II incremental impacts.

The tables presented in this section of the report are summaries without the detailed data shown. The thermal constraint summary tables indicate the worst loading seen from each phase. The worst loading figure is compiled from applicable cases. MISO facilities that experience a higher loading in the IS partial path cases than in the cases without the IS partial path requests are listed with loading values from the non-IS case, since that is what will be the maximum loading level from a tariff standpoint that would be required to be mitigated. Non-MISO MAPP facilities are listed with the higher loading from these two cases (with and without IS partial paths). The same principle holds true for the voltage summaries. The full set of results can be found in the appendices.

In the summary tables, an N/A entry refers to not an applicable constraint to the particular scenario and phase of the study. Regional criteria, policies and practices have been utilized when determining whether or not an element should be listed as a constraint in the conclusion.

8.1 Summary of Alternative 1 Constraints

Summaries of all thermal and steady state voltage concerns found are shown in Tables 8-1 and 8-2, respectively. These tables only give examples of what the outages causing concerns are and what flows and voltages are experienced. For more detailed data please refer to the sections of the report on the various phases of the study as well as the appendices.

Flowgate analysis was performed using the current list of flowgates monitored by the MAPP web-OASIS on all Alternative 1 scenarios and no flowgate constraints were found. Two MISO flowgates, MWSI and Prairie Island – Byron were impacted above the 5% DF cutoff, but were not overloaded in the models, which did include higher queue priority and confirmed transmission service requests. NDEX was also impacted by a high DF. The BSP II interconnection facilities however, will likely redefine the interface. Stability work performed in the generation interconnection study for BSP II, which assumed high stressed NDEX flows, did not indicate that BSP II would be detrimental to NDEX.

Table 8-1 below shows a summary of the thermal constraints found in Phases 1 through 4 of the Big Stone II Delivery Study for transmission alternative 1.

Facility	Contingency Example	Owner	Rating information	Phase 1 Highest MVA Loading	Phase 2 Highest MVA Loading	Phase 3 Highest MVA Loading	Phase 4 Highest MVA Loading	Note
Lakefield 345/161 kV xfmr #1	Lakefield – Wilmarth 345 kV	ALTW	335 (S & W)	N/A	399.83	382.18	N/A	1
Lakefield 345/161 kV xfmr #2	Lakefield – Wilmarth 345 kV	ALTW	335 (S & W)	N/A	399.83	382.18	N/A	1
Lakefield – Fox Lake 161 kV #1	Lakefield – Fox Lake 161 kV #P2	ALTW	160 (S)	N/A	211.82	204.75	N/A	2
Fox Lake 161/69 kV #1 xfmr	Rutland 161/69 kV xfmr	ALTW	74.7	N/A	80.53	94.96	N/A	3,4
Sheyenne – Fargo 230 k-V	Jamestown – Center 345 kV	Xcel	388 (S)	392.70	422.00	424.20	403.90	5
Minn.Valley Tap – Granite Falls 230 kV	Willmar – Granite Falls 230 kV	Xcel	387 (S)	N/A	431.15	398.69	N/A	5
Rutland – 10th Street 69 kV	Fox Lake 161/69 kV xfmr	SMMPA	36 (S)	N/A	N/A	42.15	N/A	3,4
Willmar 230/69 kV xfmr	Willmar – Kandiyohi Co.	GRE	92.4	N/A	N/A	121.22	N/A	6
St.Boni 115/69 kV xfmr	Gleason Lake 115/69 kV xfmr	GRE	87.5	N/A	N/A	113.64	N/A	4
Grant County – Elbow Lake 115 kV	SW819	MRES	160	N/A	166.42	167.25	N/A	7
Grant County – Morris 115 kV	Big Stone – Browns Valley 230 kV	MRES/OTP	Summer 96/105	113.74	131.03	124.56	149.50	5
Hankinson – Wahpeton 230 kV	Johnson Jct. – Morris 230 kV	OTP	352	N/A	N/A	349.10	455.05	5
Fargo – Maple River 69 kV	Sheyenne – Fargo 230 kV	MPC	62(S) / 72 (W)	72.63	81.45	81.18	87.41	5,8
Bismark 230/115 kV #1 xfmr	Heskett 230/115 kV xfmr	WAPA	100 Normal / 125 EM	N/A	N/A	141.14	N/A	4,5
Bismark 230/115 kV #2 xfmr	Heskett 230/115 kV xfmr	WAPA	100 Normal / 125 EM	N/A	N/A	135.70	N/A	4,5
Morris 230/115 kV xfmr	System Intact / SW937	WAPA	100 Normal / 125 EM	113	122.9	186.00	172.97	9
Bismarck DT – Bismarck EXP 115 kV	Heskett 230/115 kV xfmr	MDU	67.8	N/A	N/A	81.81	N/A	4,5
Bismarck EXP – East Bismarck 115 kV	Heskett 230/115 kV xfmr	MDU	67.8	N/A	N/A	88.13	N/A	4,5
Heskett 230/115 kV xfmr	Bismarck – East Bismarck 115 kV	MDU	125	N/A	N/A	185.12	N/A	4,5
Badoura – Laporte 115 kV	Wilton – Winger 230 kV	MPC/MP	Winter 120/132	N/A	N/A	N/A	150.35	5
Fargo – Moorhead 230 kV	Big Stone – Browns Valley 230 kV	WAPA	Winter: 239/263	N/A	N/A	N/A	246.17	5
Fargo 115/69 kV #2 xfmr	Sheyenne – Fargo 230 kV	WAPA	Winter:	N/A	N/A	N/A	128.29	5

			100/125					
Grand Forks – Pickert 230 kV	500 kV Outage	WAPA	Winter: 319/351	N/A	N/A	N/A	331.00	5,10
Jamestown – Pickert 230 kV	500 kV Outage	WAPA	Winter: 319/351	N/A	N/A	N/A	350.60	5,10
Kerkhoven – Kerkhoven Tap 115 kV	Morris 230/115 kV xmfr – SW930	GRE	All ratings: 44.82	N/A	N/A	N/A	64.09	5
Panther 230/69 kV xfmr	Panther – McLeod 230 kV	Xcel	Summer: 70/87.5	91.58	99.30	N/A	N/A	5
Willmar 115/69 kV xfmr	Willmar – Granite Falls 230 kV	GRE	Summer: 112/140	N/A	152.51	N/A	N/A	5
Leland Olds 345/230 kV #2 xfmr	Leland Olds 345/230 kV #1 xfmr	BEPC	500/700	N/A	N/A	N/A	832.43	5
Leland Olds 345/230 kV #1 xfmr	Antelope Valley – Charlie Crk, 345 kV	BEPC	250/300	294.2	325.4	N/A	358.06	5
Moorhead – Morris 230 kV	System Intact	WAPA	Winter: 239/263	N/A	N/A	N/A	311.29	5
Prairie Sw. Caps – Prairie 115 kV	Manitoba – US 500 kV outage w/ runback	MPC	All Winter: 298	N/A	N/A	N/A	310.20	5
Belfield 345/230 kV xfmr	Both Leland Olds 345/230 kV xfmrs	WAPA	250 Normal / 313 EM	N/A	N/A	253.01	331.79	5
Belfield – Charlie Creek 345	Both Leland Olds 345/230 kV xfmrs	WAPA	239 Normal / 263 EM	N/A	240.3	250.14	328.36	5

Note 1: Also observed in other study work
Note 2: Proposed operating scheme to be in place Fall 2006 would mitigate
Note 3: Future load serving needs in the Fox Lake, Fairmont, Welcome area might address
Note 4: Local generation being ramped down likely cause much of the impact
Note 5: Further studies required to determine real limitation and possible mitigation
Note 6: Future load serving needs and proposed system changes in the Willmar/Spicer area might address
Note 7: Line rating can be increased to 170 MVA by changing breakers
Note 8: Line is under some conditions operated normally open during winter peak scenarios
Note 9: Morris transformer will need to be upgraded for interconnection. Study assumes existing transformer in place.
Note 10: As emergency rating is not exceeded, issue could be mitigated via operating guide

Table 8-1 Summary of Thermal Constraints for Alternative 1

Not unexpectedly, the summer peak scenarios in Phases 1-3 show some of the same issues, while the winter peak scenario (Phase 4) shows some unique issues. Some of the constraints have been seen in various other studies as well. The Lakefield 345/115 kV transformers are known issues, as well as the Lakefield – Fox Lake # 1 161 kV constraint. The latter will likely be mitigated via an operating scheme after the new Lakefield – Fox Lake 161 kV circuit #2 is in place in the fall of 2006. This scheme will basically trip the line to protect it from overloading. The 345/115 kV transformers at Lakefield do not have an emergency rating.

Various constraints are likely driven by generation very local to the facilities in question being part of the sink definition of BSP II. For example, SMMPA's Fairmont generation might help drive the Fox Lake and Rutland area constraints. Fairmont is connected to Alliant Energy's Fox Lake 161/69 kV substation via 69 kV lines that also loops the 161 kV system eastward to Rutland. Proposed new load in this area and known load serving issues, will likely result in subsequent system upgrades to be completed in this area.

The St. Boni 115/69 kV transformer west of the Twin Cities is shown as impacted and overloaded. This is likely due to a situation similar to the Fox Lake and Rutland area issues. The St.Boni peaking plant is part of the sink definition for BSP II in some of the scenarios and it connects to the transmission grid at the same 69 kV bus as the low side of the transformer that was flagged as a problem.

116 MW of Big Stone II output goes to MDU, and of that a large portion is sunk to MDU's Heskett plant. Simply scaling down the Heskett units predominantly causes the constraints seen on the Bismarck and Heskett area facilities. Some of these issues also might be load serving issues. The 115 kV lines in the Bismarck area are reported in XCAP as limited by the conductor rating.

GRE is considering adding a new tap on the Willmar – Paynesville 230 kV line. (Spicer/Kandiyohi County 230/69 kV substation). As mentioned earlier in the report, this is only modeled in Phase 3 and 4 models. This, along with possible reconfiguration of the 69 kV system in this area which is not necessarily modeled in these studies, might address some of the Willmar area concerns.

The Hankinson – Wahpeton 230 kV line overload will have to be mitigated. The winter peak scenario shows a loading on this line significantly higher than its emergency rating. Per XCAP data, it is currently conductor limited. A definite fix has not yet been determined.

The Jamestown – Pickert – Grand Forks 230 kV line shows up as highly loaded, but not loaded above its emergency rating in the winter peak scenario (with Manitoba Hydro imports at 700 MW). Future studies will therefore look into the limiting elements of this facility, as well as possible operating procedures that can address Big Stone II's impact on these lines.

The Grant County – Elbow Lake 115 kV line loads up to about 167 MVA in the studies. This MRES owned line (which continues all the way to Alexandria) can be upgraded to a 170 MVA summer rating by replacing breakers. (Increase of the rating beyond this requires additional structures or raising of existing structures. The conductor along this section of line is capable of 320 MVA.)

The Grant County – Morris 115 kV line is also identified in the interconnection studies as a constraint. A physical upgrade will be required to get the required capacity on this line. The exact upgrade is not yet known. The Morris 230/115 kV transformer is also a facility flagged that would need to be upgraded in the interconnection studies for Big Stone II. Either a 2nd transformer will be put in place or the existing transformer will be replaced with a larger unit.

Some reassessment of the Sheyenne – Fargo 230 kV constraints will be made in future study work. Center – Jamestown 345 kV is a contingency that appears to be critical to this line. This is likely a conductor limited facility.

One of the Fargo 115/69 kV transformers and the 69 kV line from Fargo to Maple River are shown as constraints. During certain conditions today, the Fargo – Maple River line is operated normally open. More study work and discussions with local Transmission Owners will take place to study this issue further. Operating the line normally open would also unload the 115/69 kV transformer at Fargo.

The Leland Olds 345/230 kV transformers will require further investigation as to the validity of the contingencies causing the overloads and the way they are operated. It is assumed in these studies that if the larger Leland Olds transformer is lost (500 MVA normal / 700 MVA emergency unit), the smaller one (250 MVA normal / 300 MVA emergency unit) automatically trips to protect it from overloading.

One of the longer facilities shown as overloaded is the Moorhead – Morris 230 kV line, which is impacted by BSP II and overloaded during system intact conditions. Its normal rating is 239 MVA and the highest flow observed is about 311 MVA. Researching XCAP data found that the summer conductor rating is 398 MVA and that winter conductor rating is 522 MVA. The facility is currently limited by current transformers. Assuming the current transformers are replaced the next limiter would be the wave traps which are rated at 320 MVA. The next limit along this line is a relay limit of 346 MVA. This line could therefore be upgraded sufficiently by replacing equipment, rather than rebuilding or reconductoring the actual line. The facility is only shown as a constraint for the winter peak scenario.

The last element listed in the table is a 115 kV tie between the switched capacitor bank bus at the Prairie substation, where there are 480 MVAr of switched capacitors connected to the Prairie 115 kV bus. This is a radial line with no other load, generation, lines, or transformers connected. With a rating of 298 MVA, this shows up for the outage of the 500 kV line between Manitoba and Minnesota. It is assumed that with the nature of the reported constraint, this is only flagged due to more capacitors switching in the case with

BSP II included, and that the rating is not applicable for this scenario. This will be verified further.

There are other constraints listed in the table and not discussed in further detail here. Future study work, Phase 6 in particular, will address the limiters on these constraints and possible mitigation thereof.

Table 8-2 on the following page shows a summary of the voltage concerns seen in Phase 1 through 4 for alternative 1.

Bus #	Bus Name	kV	Worst Contingency (lowest voltage)	Worst Change in voltage %	Worst voltage in %	Phase 1 Issue	Phase 2 Issue	Phase 3 Issue	Phase 4 Issue	Note
60719	Lafayette Tap	69	Fort Ridgley 115/69 kV xfmr	-1.57	91.45	N	N	N	Y	1,2
60720	New Ulm S	69	Fort Ridgley 115/69 kV xfmr	-.6.45	84.13	N	N	Y	Y	1,2
60721	Essig	69	Fort Ridgley 115/69 kV xfmr	-6.20	88.73	N	N	Y	Y	1,2
60746	Glenwood	69	Grant County – Elbow Lake 115 kV	-1.04	91.35	N	Y	Y	N	5
60747	Villard	69	Grant County – Elbow Lake 115 kV	-1.01	91.66	N	Y	Y	N	5
60938	Fort Ridgley	69	Fort Ridgley 115/69 kV xfmr	-6.23	85.82	N	N	Y	Y	1,2
60939	New Ulm P	69	Fort Ridgley 115/69 kV xfmr	-6.38	84.78	N	N	Y	Y	1,2
60940	New Ulm T	69	Fort Ridgley 115/69 kV xfmr	-6.26	86.08	N	N	Y	Y	1,2
60941	New Ulm N	69	Fort Ridgley 115/69 kV xfmr	-6.49	83.82	N	N	Y	Y	1,2
61649	Blanchard	115	Blanchard – Little Falls 115 kV	-1.22	94.80	N	N	N	Y	3
61784	Int’l Falls	118	Little Fork – Running 115 kV	-1.00	1.0515	N	Y	N	N	3
62005	Kerkhoven Tap	115	Willmar – Granite Falls 230 kV	-2.43	88.66	N	Y	Y	N	3
62067	Searles Jct	69	Fort Ridgley 115/69 kV xfmr	-6.25	87.05	N	N	Y	Y	1,2
62076	SCHLLNG	69	Fort Ridgley 115/69 kV xfmr	-6.15	86.01	N	N	Y	Y	1,2
62077	Schuler Tap	69	Fort Ridgley 115/69 kV xfmr	-6.13	86.13	N	N	Y	Y	1,2
62079	Lafayette Tap	69	Fort Ridgley 115/69 kV xfmr	-1.67	90.85	N	N	N	Y	1,2
62080	Home Tap	69	Fort Ridgley 115/69 kV xfmr	-1.70	90.37	N	N	N	Y	1,2
62081	New Ulm	69	Fort Ridgley 115/69 kV xfmr	-6.26	86.94	N	N	Y	Y	1,2
62082	Home	69	Fort Ridgley 115/69 kV xfmr	-1.70	90.34	N	N	N	Y	1,2
62425	Willmar	115	Willmar – Granite Falls 230 kV	-3.00	87.23	Y	Y	Y	N	3
62445	Four Corners	115	Arrowhead – Four Corners 115 kV	-2.43	86.42	N	N	Y	N	3
62530	Frazee	115	Audubon 230/115 kV xfmr	-1.08	89.8	N	N	Y	N	4
62756	Leven	69	Grant County – Elbow Lake 115 kV	-1.03	91.42	N	Y	Y	N	5
62757	Glenwood	69	Grant County – Elbow Lake 115 kV	-1.02	91.75	N	Y	N	N	5
63216	Ortonville	115	Highway 12 – Ortonville 115 kV	+5.55	110.54	N	N	N	Y	3
63235	Perham	115	Frazee – Perham 115 kV	-1.18	90.69	N	N	Y	Y	4
63287	Ortonville QAUR	115	Highway 12 – Ortonville 115 kV	+5.33	110.12	N	N	N	Y	3
67462	Detroit Lakes	115	Audubon 230/115 kV xfmr	-1.04	90.35	N	N	Y	N	4
67463	Detroit Lakes	115	Audubon 230/115 kV xfmr	-1.04	90.33	N	N	Y	N	4

Note 1: New Ulm area load serving is a known issue, and an improvement study is expected complete January 2007.
Note 2: Likely largely due to local generation being part of sink definition.
Note 3: Mitigation of issue needs further investigation.

Note 4: It was late in the study found that there's a model error in the MAPP series model that might be the cause of this issue. Additional sensitivity work will be done.
Note 5: Proposed system upgrades including capacitor banks in Alexandria, MN by MRES might address this concern

Table 8-2 Summary of Voltage Constraints for Alternative 1

Many of the voltage concerns seen are due to the same few contingencies, and are largely load serving problems, and not something that is created by the Big Stone II project. Numerous low voltage violations are seen for the loss of the Fort Ridgley 115/69 kV transformer. This is largely reflective of New Ulm / Fort Ridgley area load serving issues. New Ulm generation is part of the sink generation in the phases where the issues are seen. Turning off New Ulm generation is removing reactive support that is essential to the area in the power flow models. Local transmission owners are anticipating to complete a load serving study for this area in early 2007 and it is likely that if projects materialize from this study to address load serving needs, then issues flagged in this study will also be addressed.

One can also see numerous bus voltages in the “greater Alexandria area” as being rather low and impacted by the Big Stone II project. Loss of the transmission source west of Alexandria causes numerous 115 and 69 kV bus voltages in the area to go below acceptable criteria. MRES is planning on installing system upgrades in the Alexandria area to enhance load serving reliability and reactive support. This should address many of the voltage issues observed in the analysis, particularly in Phase 3 (2014 summer peak.) Due to the shear volume of voltage concerns observed in Phase 3, they are not all included in Table 8-2 above. Appendix C includes the detailed results. One of the proposed solutions for upgrading the Alexandria 115 kV system was tested on the Phase 3 models. The upgrade assumed that 2x25 MVAR capacitors would be installed at the Alexandria Switching Station, and that breakers would be installed at Alexandria Light and Power’s Nokomis Road substation. The breakers would allow the 115 kV loop around Alexandria to be operated normally closed, and eliminating contingencies that cause low voltages. The capacitors at the Switching Station would then be effective for helping out both ends of town, as well as beyond the city of Alexandria. Voltages even increased on the 69 kV system, largely fed from the Douglas County 115/69 kV substation some distance away from Alexandria.

Some low voltage concerns were seen on the Detroit Lakes, Perham and Frazee buses. Late in the study it was discovered that the MAPP series models utilized had an error in a line reactance in the Perham – Rush Lake 115 kV line that would cause an excessive amount of VAR consumption. Additional sensitivity work will be completed in order to reassess voltage issues observed in the area.

There are other voltage issues observed other than the ones discussed above in more detail that are included in Table 8-2. All voltage concerns will be further scrutinized in subsequent study work, particularly in the Phase 6 work that will include looking into planned and proposed system upgrades largely in Minnesota and the Dakota’s, and also as other study efforts such as the New Ulm area load serving study and the Alexandria reactive addition matures further.

8.2 Summary of Alternative 2 Constraints

Summaries of all thermal and steady state voltage concerns found are shown in Tables 8-3 and 8-4 respectively. These tables only give examples of what the outages causing concerns are and what resulting flows and voltages are due to these outages. For more detailed data please refer to the sections of the report on the various phases of the study and the appendices.

Flowgate analysis was performed using the current list of flowgates monitored by the MAPP web-OASIS on all alternative 2 scenarios and no flowgate constraints were found. Two MISO flowgates, MWSI and Prairie Island – Byron were impacted above the 5% DF cutoff, but were not overloaded in the models, which did include higher queue priority and confirmed transmission service requests. NDEX was also impacted by a high DF. The BSP II interconnection facilities, however, will likely redefine the interface. Stability work performed in the generation interconnection study for BSP II, which assumed high stressed NDEX flows, did not indicate that BSP II would be detrimental to NDEX.

Table 8-3 below shows a summary of the thermal constraints found in Phases 1 through 4 of the Big Stone II Delivery Study for transmission alternative 2.

Facility	**Contingency Example**	**Owner**	**Rating Information**	**Phase 1 Highest MVA Loading**	**Phase 2 Highest MVA Loading**	**Phase 3 Highest MVA Loading**	**Phase 4 Highest MVA Loading**	**Fix**
Lakefield 345/161 kV xfmr #1	Lakefield – Wilmarth 345 kV	ALTW	335 (S & W)	N/A	399.97	380.46	N/A	1
Lakefield 345/161 kV xfmr #2	Lakefield – Wilmarth 345 kV	ALTW	335 (S & W)	N/A	399.97	380.46	N/A	1
Lakefield – Fox Lake 161 kV #1	Lakefield – Fox Lake 161 kV #P2	ALTW	160 (S) /	N/A	211.23	204.20	N/A	1,2
Fox Lake 161/69 kV #1 xfmr	Rutland 161/69 kV xfmr	ALTW	74.7	N/A	80.44	93.97	N/A	3,4
Sheyenne – Fargo 230 kV	Jamestown – Center 345 kV	Xcel	388 (S)	N/A	N/A	393.10	N/A	5
Minn.Valley T – Granite Falls 230 kV	Willmar – Granite Falls 230 kV	Xcel	387 (S)	N/A	N/A	406.09	N/A	5
Rutland – 10th Street 69 kV	Fox Lake 161/69 kV xfmr	SMMPA	36 (S)	N/A	N/A	42.17	N/A	3,4
Willmar 230/69 kV xfmr	Willmar – Kandiyohi Co.	GRE	84/92.4	93.52	100.60	146.44	N/A	6
St.Boni 115/69 kV xfmr	Gleason Lake 115/69 kV xfmr	GRE	87.5	N/A	N/A	113.72	N/A	4
Grant County – Morris 115 kV	Big Stone – Browns Valley 230 kV	MRES	96/105	100.71	116.45	111.77	136.60	5
Hankinson – Wahpeton 230 kV	Johnson Jct. – Morris 230 kV	OTP	352	N/A	N/A	358.70	442.10	5
Bismark 230/115 kV #1 xfmr	Heskett 230/115 kV xfmr	WAPA	100/125	N/A	N/A	140.84	N/A	4,5
Bismark 230/115 kV #2 xfmr	Heskett 230/115 kV xfmr	WAPA	100 /125	N/A	N/A	135.42	N/A	4,5
Bismarck DT – Bismarck EXP 115 kV	Heskett 230/115 kV xfmr	MDU	67.8	N/A	N/A	81.51	N/A	4,5
Bismarck EXP – E Bismarck 115 kV	Heskett 230/115 kV xfmr	MDU	67.8	N/A	N/A	96.87	N/A	4,5
Heskett 230/115 kV xfmr	Bismarck – East Bismarck 115 kV	MDU	125	N/A	N/A	185.27	N/A	4,5
Badoura – Laporte 115 kV	Wilton – Winger 230 kV	MPC	120/132	N/A	N/A	N/A	152.32	5
Panther 230/69 kV xfmr	Panther – McLeod 230 kV	Xcel	70/87.5	91.33	98.60	N/A	N/A	5
Paynesville 115/69 kV #1 xfmr	Paynesville – Wakefield 115 kV P1	Xcel	47/61	65.82	70.04	62.61	N/A	5
Paynesville 115/69 kV #2 xfmr	Paynesville – Wakefield 115 kV P1	Xcel	47/61	65.12	69.30	61.95	N/A	5
Svea Tap – Litchfield Tap 69 kV	Minn.Valley Tap – Panther 230 kV	GRE	36.2	44.66	52.83	N/A	N/A	5,6
Willmar – Svea Tap 69 kV	Minn.Valley Tap – Panther 230 kV	GRE	45.5	48.32	56.49	N/A	N/A	5,6
Paynesville – Roscoe Tap 69 kV	Paynesville – Wakefield 115 kV P1	Xcel	48/52.8	60.88	69.1	61.50	N/A	5,6
Roscoe Tap – Munson Tap 69 kV	Paynesville – Wakefield 115 kV P1	Xcel	48/52.8	58.34	65.1	58.40	N/A	5.6
Farming Tap – Munson Tap 69 kV	Paynesville – Wakefield 115 kV P1	Xcel	48/52.8	55.59	62.0	54.87	N/A	5,6
Young America – Carver Co 69 kV	West Waconia – St.Boni 115 kV SW990	Xcel	47/51.7	N/A	N/A	56.20	N/A	5

Johnson Jct. – Ortonville 115 kV	Big Stone – Browns Valley 230 kV	MRES/OTP	Summer 96.6/106 Winter 126.5/139.1	N/A	N/A	124.65	147.00	5
Johnson Jct. – Morris	Big Stone – Browns Valley 230 kV	GRE	Summer: 98/108	N/A	N/A	108.18	131.02	5
Willmar – Kandiyohi 69 kV	Willmar – Kandiyohi 230 kV	GRE	All: 13.3	N/A	N/A	69.46	N/A	5,6
Kandiyohi – Green Lake 69 kV	Willmar – Kandiyohi 230 kV	GRE	All: 13.3	N/A	N/A	58.35	N/A	5,6
Leland Olds 345/230 kV xfmr #1	Antelope Valley – Charlie Crk. 345 kV	BEPC	250/300	N/A	330.7	N/A	363.86	5
Leland Olds 345/230 kV xfmr #2	Leland Olds 345/230 kV xfmr #1	BEPC	500/700	N/A	N/A	N/A	839.07	5
Belfield 345/230 kV xfmr	Both Leland Olds 345/230 kV xfmrs	WAPA	250/313	N/A	N/A	255.21	329.20	5
Belfield – Charlie Creek 345	Both Leland Olds 345/230 kV xfmrs	WAPA	239/263	N/A	239.9	252.30	331.79	5

Note 1: Also observed in other study work
Note 2: Proposed operating scheme to be in place fall 2006 would mitigate
Note 3: Future load serving needs in the Fox Lake, Fairmont, Welcome area might address
Note 4: Local generation being ramped down likely cause much of the impact
Note 5: Further studies required to determine real limitation, and possible mitigation
Note 6: Future load serving needs and proposed system changes in the Willmar/Spicer area might address
Note 7: Line rating can be increased to 170 MVA by changing breakers
Note 8: Line is under some conditions operated normally open during winter peak scenarios
Note 9: Morris transformer will need to be upgraded for interconnection. Study assumes existing transformer in place.
Note 10: As emergency rating is not exceeded, issue could be mitigated via operating guide

Table 8-3 Summary of Thermal Constraints for Alternative 2

Many of the same constraints are seen for both alternative 1 and 2. For discussion on the common elements, please refer to section 8.1. Alternative 2 does see some additional constraints on the 69 kV system in the Willmar and Paynesville area, which would not seem entirely surprising given that much of the Big Stone II output would be flowing on a new 230 kV line from Big Stone to Willmar.

In addition constraints are also seen on the Ortonville – Johnson Jct. – Morris 115 kV facilities that are not evident in the alternative 1 analysis (i.e. alternative 1 itself upgrades this line and therefore does not see the 115 kV constraints.) If alternative 2 is to be built, this line still would have to be upgraded, but remain at 115 kV rather than rebuilding it to 230 kV as is part of alternative 1.

Table 8-4 on the following page shows a summary of the voltage concerns seen in Phases 1 through 4 for the Big Stone II Delivery Study assuming transmission alternative 2.

Bus #	Bus Name	kV	Worst Contingency (lowest voltage)	Worst Change in voltage %	Worst voltage in %	Phase 1 Issue	Phase 2 Issue	Phase 3 Issue	Phase 4 Issue	Fix
60686	East Melrose	69	Douglas County 115/69 kV xfmr	-1.02	88.90	N	N	Y	N	6
60719	Lafayette Tap	69	Fort Ridgley 115/69 kV xfmr	-1.30	91.72	N	N	N	Y	1,2
60720	New Ulm S	69	Fort Ridgley 115/69 kV xfmr	-5.82	84.49	N	N	Y	Y	1,2
60721	Essig	69	Fort Ridgley 115/69 kV xfmr	-1.66	89.10	N	N	N	Y	1,2
60746	Glenwood	69	Grant County – Elbow Lake 115 kV	-1.37	84.07	Y	Y	Y	N	5
60747	Villard	69	Douglas County 115/69 kV xfmr	-1.23	84.07	N	Y	Y	N	6
60748	West Port	69	Douglas County 115/69 kV xfmr	-1.14	83.57	N	N	Y	N	6
60749	Douglas County	69	Douglas County 115/69 kV xfmr	-1.14	81.38	N	N	Y	N	6
60750	Osakis	69	Douglas County 115/69 kV xfmr	-1.17	81.44	N	N	Y	N	6
60751	Sauk Center	69	Douglas County 115/69 kV xfmr	-1.13	84.02	N	N	Y	N	6
60752	Black Oak	69	Douglas County 115/69 kV xfmr	-1.13	87.60	N	N	Y	N	6
60753	Meir Grove	69	Douglas County 115/69 kV xfmr	-1.05	87.60	N	N	Y	N	6
60754	Melrose Muni	69	Douglas County 115/69 kV xfmr	-1.07	89.04	N	N	Y	N	6
60768	Elrosa Tap	69	Douglas County 115/69 kV xfmr	-1.03	91.31	N	N	Y	N	6
60916	Garwind	69	Maple Leaf – Cascade Creek 161 kV	-3.71	93.50	N	N	N	Y	3
60938	Fort Ridgley	69	Fort Ridgley 115/69 kV xfmr	-5.61	86.17	N	N	Y	Y	1,2
60939	New Ulm P	69	Fort Ridgley 115/69 kV xfmr	-5.75	85.13	N	N	Y	Y	1,2
60940	New Ulm T	69	Fort Ridgley 115/69 kV xfmr	-5.62	86.43	N	N	Y	Y	1,2
60941	New Ulm N	69	Fort Ridgley 115/69 kV xfmr	-5.85	84.17	N	N	Y	Y	1,2
61649	Blanchard	115	Blanchard – Little Falls 115 kV	-1.61	94.41	N	N	N	Y	3
61784	Int'l Falls	118	Little Fork – Running 115 kV	+1.1	1.0515	N	Y	N	N	3
62005	Kerkhoven Tap	115	Willmar – Granite Falls 230 kV	-2.29	90.73	N	Y	N	N	3
62067	Searles Jct	69	Fort Ridgley 115/69 kV xfmr	-5.59	87.41	N	N	Y	Y	1,2
62076	SCHLLNG	69	Fort Ridgley 115/69 kV xfmr	-5.53	86.35	N	N	Y	Y	1,2
62077	Schuler Tap	69	Fort Ridgley 115/69 kV xfmr	-5.52	86.47	N	N	Y	Y	1,2
62079	Lafayette Tap	69	Fort Ridgley 115/69 kV xfmr	-1.39	91.13	N	N	N	Y	1,2
62080	Home Tap	69	Fort Ridgley 115/69 kV xfmr	-1.32	90.75	N	N	N	Y	1,2
62081	New Ulm	69	Fort Ridgley 115/69 kV xfmr	-5.60	87.30	N	N	Y	Y	1,2
62082	Home	69	Fort Ridgley 115/69 kV xfmr	-1.31	90.73	N	N	N	Y	1,2
62425	Willmar	115	Willmar – Granite Falls 230 kV	-2.91	87.59	N	Y	N	N	3
62445	Four Corners	115	Arrowhead – Four Corners 115 kV	-2.49	86.36	N	N	Y	N	3

62530	Frazee	115	Audubon 230/115 kV xfmr	-1.22	89.66	N	N	Y	N	4
62755	Omen	69	Douglas County 115/69 kV xfmr	-1.14	83.66	N	N	Y	N	6
62756	Leven	69	Douglas County 115/69 kV xfmr	-1.27	84.95	N	Y	Y	N	6
62757	Glenwood	69	Grant Co – Elbow Lake 115 kV	-1.35	87.25	Y	Y	Y	N	5
62820	West Union	69	Douglas County 115/69 kV xfmr	-1.15	82.25	N	N	Y	N	6
62821	Kandota	69	Douglas County 115/69 kV xfmr	-1.13	84.17	N	N	Y	N	6
62822	Kandota Tap	69	Douglas County 115/69 kV xfmr	-1.13	84.47	N	N	Y	N	6
62823	Elrosa	69	Douglas County 115/69 kV xfmr	-1.13	90.80	N	N	Y	N	6
62847	Grove	69	Douglas County 115/69 kV xfmr	-1.06	87.47	N	N	Y	N	6
63220	Elbow Lake	115	SW938	-1.37	89.05	N	Y	Y	N	5
63235	Perham	115	Frazee – Perham 115 kV	-1.44	83.38	N	N	Y	Y	4
66789	Bemidji	115	Wilton 230/115 kV xfmr	-4.43	91.84	N	N	N	Y	3
67462	Detroit Lakes	115	Audubon 230/115 kV xfmr	-1.20	90.19	N	N	Y	N	3,4
67463	Detroit Lakes	115	Audubon 230/115 kV xfmr	-1.19	90.18	N	N	Y	N	3,4
67464	Detroit Lakes	115	Audubon 230/115 kV xfmr	-1.18	90.42	N	N	Y	N	3,4

Note 1: New Ulm area load serving is a known issue, and an improvement study is expected complete January 2007.
Note 2: Likely largely due to local generation being part of sink definition.
Note 3: Mitigation of issue needs further investigation.
Note 4: It was late in the study found that there's a model error in the MAPP series model that might be the cause of this issue. Additional sensitivity work will be done.
Note 5: Proposed system upgrades including capacitor banks in Alexandria, MN by MRES might address this concern
Note 6: Loss of Douglas County 115/69 kV transformer is problematic. Likely also load serving issue.

Table 8-4 Summary of Voltage Constraints for Alternative 2

Most of the voltage concerns seen for Alternative 2 were also seen and discussed for Alternative 1. Some additional concerns were seen for various 69 kV voltages during the loss of the Douglas County 115/69 kV transformer. Many of these voltages are helped out by the proposed Alexandria area system additions, but tripping the Douglas County transformer will essentially isolate these 69 kV buses from the benefits of the additional capacitors at Alexandria. By nature of alternative 2, and looking at the thermal results for alternative 2 as well, it seems more loop flow goes on the 69 kV system between Douglas County and Paynesville, which causes both additional thermal and voltage concerns as compared to alternative 1.

Another additional voltage concern observed is the Garwind 69 kV bus for loss of the Maple Lead – Cascade Creek line. The voltage is above 93%, but treated as an Xcel generator bus (for the Garwin McNeilus wind farm near Dodge Center, MN) and 95% low voltage criteria was assumed. More sensitivity work will be done to make sure that shunt capacitors in the area are operating as desired.

8.3 General Conclusion

Sections 8.1 and 8.2 summarize constraints on the system that the Big Stone II project will have to mitigate for obtaining transmission service and not degrade the reliability of the transmission system.

For many of the constraints observed, there has not yet been a determination made as to what the mitigating step will be. Many concerns are expected to be addressed by load serving efforts that are currently underway at the time this report is being written and the BSP II project will need to wait for study work to be completed before reasonable and likely assumptions can be made for future studies to verify that the constraints will be addressed.

There are also larger scale efforts underway in Minnesota and bordering areas that might address many of the concerns identified. The CapX effort is currently looking at the following facilities to be built within the next several years:

- 345 kV from Brookings County (near White, SD) – Lyon County – Helena (tap on Wilmarth – Blue Lake 345 kV) – Lake Marion – Hampton Corner, with a 345 kV line from Lyon County – Hazel Run (near Granite Falls). Likely with this line in-service the Big Stone – Canby – Granite Falls 230 kV line will be converted to a Big Stone – Canby – Hazel Run 345 kV line. The Hazel Run substation will have connections to the Granite Falls and Minnesota Valley substations.
- 345 kV from Fargo – Alexandria – St.Cloud – Monticello
- 345 kV from Hampton Corner – Rochester – Lacrosse
- 230 kV from Boswell – Wilton

This list is referred to as CapX Group 1. The first line listed above is expected to help address many of the constraints found in this Delivery Study as it will likely interconnect with the new transmission line common to both transmission alternatives. Phase 6 of Big Stone II studies is scheduled to be started in early 2007, and will look at the effect of the planned and proposed CapX lines, as well as other planned and proposed system upgrades. It should also be noted that with these major new power lines being proposed by CapX, a separate study is underway by the CapX team to accommodate these high voltage lines and to identify what underlying (230 kV and below) system changes would have to be done. There are also other Extra High Voltage (EHV) lines under investigation beyond CapX Group 1. (For more information visit www.capx2020.com). Other study efforts that have been completed, or are underway that could also result in facility upgrades in the MAPP footprint are:

- Buffalo Ridge Incremental Outlet study: This study looked at new 115 kV class facilities that could enhance the wind outlet capabilities of the Buffalo Ridge wind generation, without the need to build EHV facilities. The study resulted in a recommendation for a 2nd 115 kV line from Fenton – Nobles County, with a 2nd 345/115 kV transformer at the Nobles County substation along with an additional line from Lake Yankton to Marshall, MN. Some upgrades of existing lines were also identified as being needed.
- Storden, Dotson, New Ulm area study: Study work is currently being completed for this area to address load serving needs and other issues to determine possible system upgrades.

Throughout the report, balancing area losses are reported for the different phases, transmission alternatives, and with and without the IS partial path requests. In summary, it can be observed that the transmission system losses assuming transmission alternative 2 is implemented, is greater than if transmission alternative 1 is implemented. This is true for the overall system, but is not necessarily true for individual balancing areas. Further loss analysis will be performed for Phase 5 and 6 as well. Phase 6 is expected to change (reduce) the overall loss figures since it will include the 345 kV CapX facility from Brookings County, SD to the southeast Twin Cities metro area as well as other larger transmission projects.

In addition to the study work presented herein identifying steady state delivery constraints, an additional phase of the study will also be completed to adhere to MAPP DRS requirements. This will be Phase 5 and will investigate summer off-peak conditions with high stressed interfaces.

Three study assumptions that have changed since the study started which might have an impact on the results are:

- The Perham – Rush Lake 115 kV line reactance error (noted above in section 5.4)
- The recent refusal of the 200 MW White wind farm in the partial path cases (noted above in section 4.1.2)
- The presence of a prior queued WAPA/IS OASIS request that could be at Huron, SD

Another study assumption that could affect the results of the interconnection and delivery studies are two interconnection requests totaling 600 MW (GI-0318 - 500 MW, July 2003; and GI-0323 - 100 MW, Aug 2003) and a 500 MW of delivery service request (#736108) on the WAPA/IS OASIS queued prior to Big Stone II. This interconnection, on the WAPA/IS OASIS is identified to be in North Central South Dakota and could potentially result in a project being located near Huron. During the OASIS review process in 2005 and model building efforts since that time, completed in close coordination with WAPA, there has been no substantial change in availability of information to reasonably model this potential project. This 600 MW interconnection request and 500 MW delivery service request has not substantially developed during the Big Stone II interconnection and delivery studies. However, very recently, an indication has been received from WAPA about the availability of some modeling information for this potential plant in North Central South Dakota located near Huron. No study work or modeling detail has been provided as of the date of this submittal. Due to the size of this potential project on the WAPA/IS OASIS this project could have an impact on the results of this study. However, due to the lack of information, this project could not reasonably be included in this study submittal. More discussion with the transmission provider is required to determine how to proceed on this issue with respect to the Big Stone II interconnection and delivery studies.

MAPP DRS and MISO will be kept up to date and asked to approve future study work that addresses Big Stone II Delivery Issues. In this process the project will also continue to solicit input from potentially impacted transmission owners, and provide updates to the Missouri Basin and Northern MAPP Sub-regional Planning Groups.

Big Stone II – Delivery Study Phase 6 and Supplemental #2

For Northern MAPP SPG Meeting

4/3/07

Elk River

Richard Dahl

Missouri River Energy Services

Study phases

- Phase 1:
  2009 Summer Peak w/ only confirmed reservations for MISO and MAPP DRS.
- Phase 2:
  2009 Summer Peak w/ confirmed and prior queued study mode reservations for MISO and MAPP DRS.
- Phase 3:
  2014 Summer Peak w/ confirmed and prior queued study mode reservations for MISO and MAPP DRS.
- Phase 4:
  2010/11 Winter Peak w/ confirmed and prior queued study mode reservations for MISO and MAPP DRS.
- Phase 5:
  High Transfer (MWSI = 1480 MW, MHEX_S=2175 MW, NDEX=2080 MW pre-BSP II) summer off-peak (70% of peak) for MAPP DRS only.
- Phase 6 …… we will go through the scope in more detail later in the presentation.

Where are we at with studies?

- Phase 1-4 studies submitted to DRS in August 2006, and approved (with contingent items) November 2006.
- Phase 5 studies submitted to DRS in September 2006, and approved (with contingent items) November 2006.
- Supplemental report 1 submitted to DRS in November 2006. This report removed some contingent items associated with Phase 1-4.

Where are we at with studies – cntd

- A Supplement 2 report was submitted to the DRS, and approved on 3/30 removing the following contingent items:
  - Bismarck area 115 kV lines : These will be upgraded by the end of the year.
  - Kerkhoven – Kerkhiven Tap 115 kV: Line rating has increased sufficiently.
  - Blanchard 115 kV bus voltage: Criteria is 0.92 not 0.95 pu. Also misc. upgrades increase voltage to above 0.97 pu.
  - Four Corners 115 kV bus voltage: 115 kV bus w/o load or generation fed from 69 kV. Not a concern.
  - International Falls 115 kV: Not issue per discussions w/ MP.
- There a still more contingent items to resolve
- Phase 6 Delivery Service Study will be submitted to DRS tentatively for their June Meeting, but report should be complete well in advance of this.
- Not seeking action from NM SPG today. Just informing the group of where we're at and looking for any feedback.

Phase 6 Study

- Scope was sent out earlier to TO ad hoc group. Draft report also sent out about 2 weeks ago for ad hoc group to comment on.
- Ad hoc group was also solicited on model updates
- Thanks to all that helped review!

Phase 6 Study Scope

- Currently there's two transmission expansion alternatives on the table:
  - Alternative 1: Big Stone – Johnson Jct. – Morris 230 kV + Big Stone – Canby – Granite Falls 230 kV
  - Alternative 2: Big Stone – Willmar 230 kV + Big Stone – Canby – Granite Falls 230 kV
- The project has stated along with the Minnesota Certificate of Need application that Alternative 1 is the preferred alternative.
- Phase 6 so far is only studying Alternative 1. Alternative 2 will only be studied further as needed.

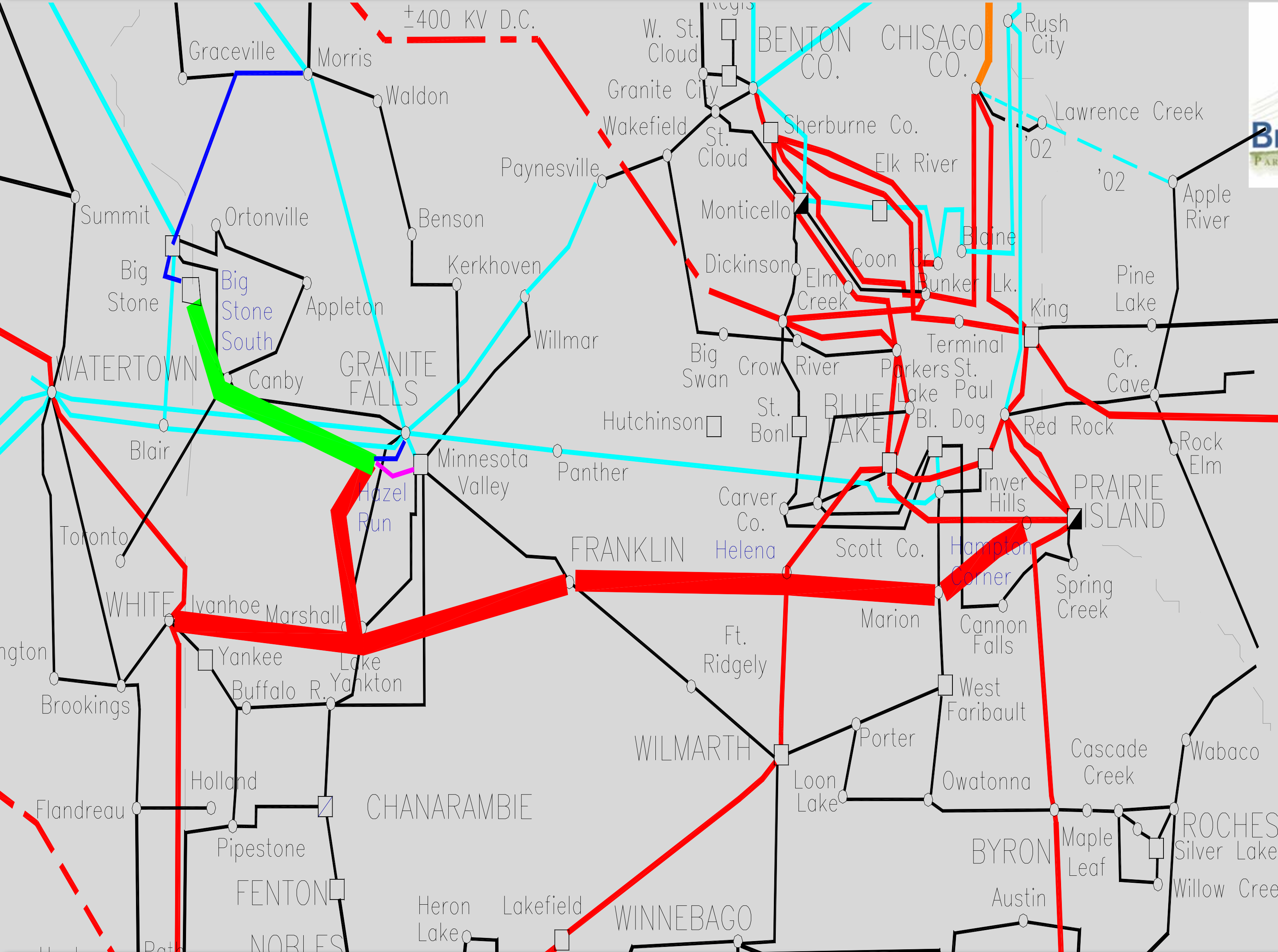
Phase 6 Study Scope – cntd

- Steady state analysis for Delivery Service studies
- Two major goals of Phase 6 Studies
  - Evaluate the impact of converting Big Stone – Canby – Granite Falls 230 kV to 345 kV
    - Additional constraints? Less constraint?
  - Evaluate the impact of other projects
    - MTEP projects listed as planned
    - CapX Brookings Co. – SE Twin Cities 345 kV
    - Misc. model updates
- Also tabulate losses

Converting Big Stone – Canby – Granite Falls 230 kV to 345 kV

- The line conversion would mean that there would be a 345 kV line from Big Stone area tying into the Brookings County, SD – SE Twin Cities CapX project.
- The termination point for the 345 kV would be at the proposed Hazel Run substation near Granite Falls.
- Only studied in a post-CapX world (the one project only).

Big Stone
Partners in Transmission



Impact of converting Granite Falls 230 kV line to 345 kV

- Studies shows no non-flowgate Significantly Affected Facilities per the MAPP DRS criteria. This is true for both voltage and thermal steady state analysis
- Flowgate analysis performed:
  - Using DFCALC w/ currently posted DFCALC input file.
  - Using DFCALC w/ updated DFCALC input file to include flowgates currently monitored by the MAPP OASIS
  - Using MISO's monitored element file for MUST
  - ➔ No flowgate violations found
- Some facilities are unloaded (yet to be fully tabulated)

Impact of other transmission upgrades

- Blanchard 115 kV low voltage violation is no longer present due to system upgrades on the 115 kV system.
- Alexandria Area bus voltage violations
  - Many go away, some remains at Miltona, Elbow Lake, Grant County, and Brandon
  - Largely caused by MRES upgrades in the Alexandria area
- Erroneous voltage criteria
  - A 0.92 pu. low voltage criteria used for Glenwood and Villard 69 kV as opposed to less strict 0.90 pu. No longer in violation.
- Bismarck Downtown – Bismarck Expressway – East Bismarck 115 kV is no longer constraint when reconductored/ rebuilt to 160 MVA.

cntd

- CapX helps constraints found earlier
  - Kerkhoven Tap 115 kV bus voltage within criteria
  - Granite Falls – Minnesota Valley 230 kV loading well below normal rating at 56%
  - Fargo – Moorhead 230 kV loading below normal rating
  - Fargo 115/69 kV xfmr #2 loading down to emergency rating for relevant contingencies (as opposed to above emergency rating previously).
  - Belfield 345/230 kV xfmr loading below emergency rating. Contingency is loss of large Leland Olds 345/230 kV xfmr with cross-trip of the smaller one. Winter scenario sees the highest flows.
  - New Ulm area bus voltages is helped somewhat with the new Franklin 345/115 kV substation. However 115 and 69 kV is still a constraint for serving load in the area. Study on how to enhance load serving in this area is being performed w/ Xcel as lead.

Losses

- A small increase seen in the summer peak scenario
- A small decrease seen in the winter peak scenario

Going forward…

- Report will be submitted to MISO when complete.
- Report will submitted to MAPP DRS for approval tentatively at their June meeting, if not sooner.
- Goal: To have a final report in April

Questions?

Deliverability Study Report for Project G392

1. Project Description

MISO Interconnection Queue Number	38020-01
Requested Maximum Output level (MW)	600
County	Grant
State	SD
Control Area / Transmission Owner	OTP

2. Introduction

Generator interconnection projects have to pass Generator Deliverability Study to be granted Network Resource Interconnection Services (NRIS). Interconnection projects that had not filed an Interconnection Agreement (IA) by 9/1/2004 are studied in their interconnection queue order to determine their deliverability.

For projects that have already signed IA but are still waiting for the deliverability study results, this report will be attached to its IA or System Impact Study report. If the generator is determined as not fully deliverable and wants to pursue full deliverability, the customer has to submit a new interconnection to MISO to do so.

For projects that are still in study mode, this report is attached to its system impact study report. If the generator is determined as not fully deliverable, the customer can choose either to change his project to an Energy Resource (ER) project or proceed with the system upgrades that will make the generator fully deliverable.

Since Generator Deliverability Study is to ensure Resource Adequacy during system peak condition, wind generators are tested at 20% of its maximum output level, and this is the maximum level that can be used to meet Resource Adequacy under Module E of the Midwest ISO Transmission and Energy Market Tariff (TEMT), unless the generator owner can demonstrate that the generator’s capacity factor during SUMMER PEAK is greater than 20%.

3. Study Methodology

MISO Generator Deliverability Study whitepaper describing the algorithm can be found at “http://www.midwestmarket.org/publish/Document/3e2d0_106c60936d4_-767f0a48324a”

4. Determining the MW restriction

If one facility is overloaded based on the assessed “severe yet credible dispatch” scenario described in the study methodology, and the generator under study is in the

"Top 30 DF List" (see white paper for detail), part or all of its output is not deliverable. The restricted MW is calculated as following:

(MW restricted) = (worst loading – MW rating) / (generator sensitivity factor)

If the result is larger than the maximum output of the generator, 100% of this generator's output is not deliverable.

The generator is also responsible for any NEW base case (pre-shift) overload or NEW "severe yet credible dispatch overload" where the generator is not in the "Top 30 DF List", if the generator's DF is greater than 5%. Please see white paper for detail. The formula above also applies to these situations.

5. Study Result

☐ This generator is determined to be fully deliverable (MW). No constraint found.

☒ This generator is not fully deliverable due to the following constraint(s):
Alternative 1

63219 GRANTCO7 115 66555 MORRIS 7 115 1
For the loss of
63329 WAHPETN4 230 63331 FERGSFL4 230 1 (262.1 MW deliverable)

Alternative 2

63219 GRANTCO7 115 66555 MORRIS 7 115 1
For the loss of
63329 WAHPETN4 230 63331 FERGSFL4 230 1   (267.7 MW deliverable)

6. Conclusion

☐   MW from this generator is deliverable based on MISO Generator Deliverability Study result.

☒ This generator is not fully deliverable without system upgrade. The following upgrades are necessary to make it fully deliverable (600 MW):

- Project G392 was studied for both alternative 1 and 2, the constraints limiting the full deliverability of this unit are listed above. The details on these constraints are listed in section 7 below

- The Grant County -- Morris 115kV is the most limiting constraint, it was also identified in the System Impact Study and the delivery service studies.
- Without any upgrades, G392 is 262.1 MW deliverable via alternative 1 and 267.7 MW deliverable using alternative 2

7. Appendix A: Constraints for this project's deliverability

A description of the format of the constraint information can be found in Appendix B.

Alternative 1

Branches	Contingencies	line rating	pre-shift flow	post_shift flow	DFAX	Worst loading	MW restricted
63050 WILLMAR4 230[1] 66550 GRANITF4 230 1	63327 HANKSON4 230 63329 WAHPETN4 230 1	231.5	228.4	234.9	8.1%	234.9	41.4
63050 WILLMAR4 230 66550 GRANITF4 230 1	63325 BROWNSV4 230 63327 HANKSON4 230 1	231.5	229.3	236.5	8.9%	236.5	56.2
63050 WILLMAR4 230 66550 GRANITF4 230 1	**63314 BIGSTON4 230 63325 BROWNSV4 230 1**	**231.5**	**230.2**	**237.4**	**8.9%**	**237.4**	**66.4**
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	102.3	113.9	116.7	7.1%	116.7	202.5
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63327 HANKSON4 230 63329 WAHPETN4 230 1	102.3	117.2	119.8	6.2%	119.8	280.8
63219 GRANTCO7 115 66555 MORRIS 7 115 1	**63329 WAHPETN4 230 63331 FERGSFL4 230 1**	**102.3**	**120.1**	**122.6**	**6.0%**	**122.6**	**337.9**

[1] The Willmar - Granite Falls 230 kV line has been upgraded to allow the full conductor rating of 383 MVA to be realized. Therefore this line will no longer be limiting the deliverability of the G392 project.

Constraint 1:

Branch	Contingency	MW rating	PreShift Loading	Add. flow from top 30 list	ER flow adjustment	Worst loading
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63329 WAHPETN4 230 63331 FERGSFL4 230 1	102.3	120.1	2.5	-0.1	122.6
Gen #	**Gen**	**Pgen**	**Pmax**	**Sensitivity**	**(add.) flow contribution**	**NR/ER**
60374	FIBROMN7 115	49.0	50.0	10.2%	0.1	NR
62013	BENSON 941.6	0.0	12.2	10.2%	1.2	NR
63315	BIGSTN1G24.0	493.5	495.0	6.0%	0.1	NR
66666	BIGSTN2G25.0	654.6	655.0	6.0%	0.0	NR
63215	HIWY12 7 115	1.5	6.0	5.9%	-0.1	ER
63209	HETLAND7 115	0.0	21.2	5.4%	1.2	NR

Constraint 2:

Branch	Contingency	MW rating	PreShift Loading	Add. flow from top 30 list	ER flow adjustment	Worst loading
63050 WILLMAR4 230 66550 GRANITF4 230 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	231.5	230.2	7.2	-0.1	237.4
Gen #	**Gen**	**Pgen**	**Pmax**	**Sensitivity**	**(add.) flow contribution**	**NR/ER**
63209	HETLAND7 115	0.0	21.2	10.4%	2.2	NR
63215	HIWY12 7 115	1.5	6.0	9.2%	-0.1	ER
63315	BIGSTN1G24.0	493.5	495.0	8.9%	0.1	NR
66666	BIGSTN2G25.0	654.6	655.0	8.9%	0.0	NR
60148	MINVALY7 115	0.0	45.4	8.5%	3.8	NR

60691	GRNFLCY869.0	0.0	7.4	6.7%	0.5	NR
60858	HADLEY 869.0	1.0	2.0	5.3%	0.1	NR
1116	G252_80 69.0	0.0	8.0	5.2%	0.0	ER
1117	G252_20 69.0	0.0	2.0	5.2%	0.1	NR
1272	G272_80 69.0	0.0	8.0	5.1%	0.4	NR
1273	G272_20 69.0	0.0	2.0	5.1%	0.0	ER
61956	R.FALLS7 115	5.1	6.1	5.0%	0.1	NR

Alternative 2

Branches	Contingencies	line rating	pre-shift flow	post_shift flow	DFAX	Worst loading	MW restricted
63050 WILLMAR4 230 66550 GRANITF4 230 1	63327 HANKSON4 230 63329 WAHPETN4 230 1	231.6	227.7	234.6	8.1%	234.6	36.6
63050 WILLMAR4 230 66550 GRANITF4 230 1	63325 BROWNSV4 230 63327 HANKSON4 230 1	231.6	228.5	236.1	8.9%	236.1	51.1
63050 WILLMAR4 230 66550 GRANITF4 230 1	**63314 BIGSTON4 230 63325 BROWNSV4 230 1**	**231.6**	**229.4**	**237.0**	**8.9%**	**237.0**	**61.3**
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	102.3	113.4	116.6	7.1%	116.6	200.5
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63327 HANKSON4 230 63329 WAHPETN4 230 1	102.3	116.7	119.6	6.2%	119.6	277.9
63219 GRANTCO7 115 66555 MORRIS 7 115 1	**63329 WAHPETN4 230 63331 FERGSFL4 230 1**	**102.3**	**119.7**	**122.5**	**6.0%**	**122.5**	**336.3**

Constraint 1

Branch	Contingency	MW rating	PreShift Loading	Add. flow from top 30 list	ER flow adjustment	Worst loading
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63329 WAHPETN4 230 63331 FERGSFL4 230 1	102.3	119.7	2.8	-0.1	122.5
Gen #	**Gen**	**Pgen**	**Pmax**	**Sensitivity**	**(add.) flow contribution**	**NR/ER**
60374	FIBROMN7 115	49.0	50.0	10.2%	0.1	NR
62013	BENSON 941.6	0.0	12.2	10.2%	1.2	NR
63315	BIGSTN1G24.0	493.0	495.0	6.0%	0.1	NR
66666	BIGSTN2G25.0	650.0	655.0	6.0%	0.3	NR
63215	HIWY12 7 115	1.5	6.0	5.9%	-0.1	ER
63209	HETLAND7 115	0.0	21.2	5.4%	1.2	NR

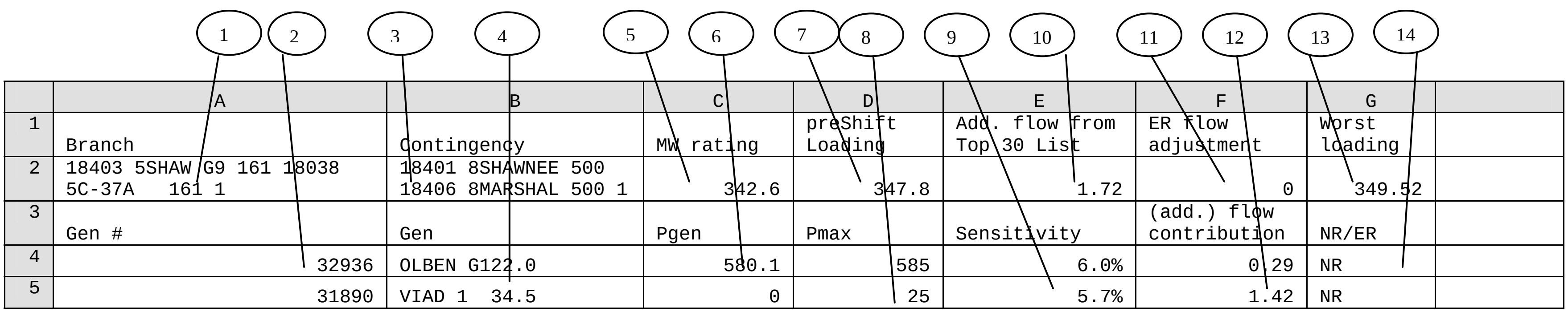
Constraint 2

Branch	Contingency	MW rating	PreShift Loading	Add. flow from top 30 list	ER flow adjustment	Worst loading
63050 WILLMAR4 230 66550 GRANITF4 230 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	231.6	229.4	7.6	-0.1	237
Gen #	**Gen**	**Pgen**	**Pmax**	**Sensitivity**	**(add.) flow contribution**	**NR/ER**
63209	HETLAND7 115	0.0	21.2	10.4%	2.2	NR
63215	HIWY12 7 115	1.5	6.0	9.2%	-0.1	ER
63315	BIGSTN1G24.0	493.0	495.0	8.9%	0.2	NR
66666	BIGSTN2G25.0	650.0	655.0	8.9%	0.4	NR
60148	MINVALY7 115	0.0	45.4	8.5%	3.8	NR

60691	GRNFLCY869.0	0.0	7.4	6.7%	0.5	NR
60858	HADLEY 869.0	1.0	2.0	5.3%	0.1	NR
1116	G252_80 69.0	0.0	8.0	5.2%	0.0	ER
1117	G252_20 69.0	0.0	2.0	5.2%	0.1	NR
1272	G272_80 69.0	0.0	8.0	5.1%	0.4	NR
1273	G272_20 69.0	0.0	2.0	5.1%	0.0	ER
61956	R.FALLS7 115	5.1	6.1	5.0%	0.1	NR

8. Appendix B: How to read the generator deliverability study result.

A typical deliverability result looks like the following table (Flow and output are all in MW):



1. The name of the branch that is limiting.

2. The bus number in the “deliverability case”.
3. The name of the contingency.
4. Bus name.
5. Branch MW rating, estimated by MUST. Although the first screening was done using DC algorithm by MUST, all violations were then checked using full AC powerflow and using branch MVA rating.
6. Generator initial output in “deliverability case”.
7. The branch loading before generator output adjustment.
8. Maximum MW output capacity from this bus in this deliverability case.
9. The generator’s sensitivity on the limiting branch. The sink is all MISO generation when MUST calculates this number.
10. Total incremental MW flow on branch by adjusting generator output levels: NRs in the “Top 30 DF List” are run up to their Pmax; Offline NRs outside of the “Top 30 DF List” but with 20% line rating impact are run up to their Pmax; ERs with larger than 5% sensitivity (contributing flow only) are turned down to 0MW. Please refer to the MISO generator deliverability procedure for detail. (In the example shown, E2 = SUM(F4:F5))
11. Total branch flow from impact of ER units. This number is already included in calculating the number in 10. Please refer to the MISO generator deliverability procedure for detail.
12. This generator’s additional contribution on the branch flow by running it up to Pmax. If this is an ER with positive sensitivity, the contributions is from turning off the generator.
13. (worst loading) = (pre-shift loading) + (flow adjustment). G2 = D2 + E2.
14. The status of this generator: Network Resource (NR) or Energy Resource (ER).