Capacity Validation Study

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Minnesota Transmission Owners (MTO)

Basin Electric Power Cooperative
(also representing East River Electric Power Cooperative and L&O Power Cooperative)
Central Minnesota Municipal Power Agency
Dairyland Power Cooperative
Great River Energy
Heartland Consumers Power District
Interstate Power and Light
Minnesota Municipal Power Agency
Minnesota Power
Minnkota Power Cooperative
Missouri River Energy Services
(also representing Hutchinson Utilities Commission and Marshall Municipal Utilities)
Northern States Power, a Minnesota Corporation (" Xcel Energy")
Otter Tail Power Company
Rochester Public Utilities
Southern Minnesota Municipal Power Agency
Willmar Municipal Utilities

- The Minnesota Transmission Owners are utilities that own or operate high voltage transmission lines. When originally formed, this group was made up of those utilities subject to 2001 legislation requiring transmission owners to file a biennial transmission report. Additional utilities have joined the MTO to collaborate on transmission studies.

Table of Contents

Index of Tables

Index of Figures

I. Executive Summary

This report summarizes an extensive analysis undertaken by the Minnesota Transmission Owners (MTO) to identify the impacts that will occur on the regional transmission system with the addition of several new transmission facilities. This analysis is called the Capacity Validation Study (CVS).

This study looked at several specific transmission projects, taken individually and in combination, to determine how much additional generation can be added to the system and where as a result of the transmission additions. The results provide an estimated range of additional generation that can be added by these various combinations of transmission projects along with estimated locations of new generation. The study also sought to verify and validated the transfer capabilities which have been estimated by other studies.

Background

This study is part of the effort undertaken by Minnesota Transmission Owners to assess the transmission system in the upper Midwest for improvements necessary to develop a robust and reliable transmission system that will:

(i) allow the development of generation projects that satisfy the Renewable Energy Standard legislation milestones,
(ii) continue to enable reliable, low cost energy for the region, and
(iii) continue developing a robust and reliable transmission system.

Transmission planning studies tend to fall into two broad categories: vision studies and Certificate of Need studies. Vision studies take a high level, indicative look at transmission needs. A Certificate of Need study is a more thorough analysis of the transmission system and is required by regulators to move forward to the next steps of constructing a transmission system. The CVS described in this report is considered a vision study.

The state of Minnesota has legislative and regulatory requirements that mandate Minnesota's load serving utilities to take significant actions to enable substantial growth in the development and use of renewable electricity. Minnesota's Next Generation Energy Act of 2007 enacted the Renewable Energy Standard (RES) which requires that 25 percent of the electricity consumed in Minnesota be generated by renewable resources by 2025. Additionally, the RES requires Xcel Energy to meet 30 percent of its customers' electricity needs with renewable sources by 2025.

The Minnesota RES has become a significant factor in the need to expand the transmission network in the Upper Midwest. Essentially, load serving entities will need to obtain in the range of 4,000 – 6,000 MW of nameplate wind (or other renewable) energy generation by 2025. In order for load serving entities to fulfill that requirement, significant transmission infrastructure will need to be constructed in order to assure that a robust and reliable system is maintained after addition of that generation.

Several transmission projects are either under construction, being permitted, being proposed, and/or being studied that address the need to develop a robust and reliable network that will be available for load serving entities to be able to meet the renewable energy standards in this region. Even though technical studies have been completed for each of these transmission projects individually or in combination with only a few projects together, such as through the CapX2020 [1]Vision Study, a thorough technical evaluation of all transmission projects in combination had not been performed until this study work began.

It is important to note that this study's focus was on transmission planning, the costs of transmission projects, and the level of generation that might be enabled by transmission upgrades. Based on the Midwest ISO generation interconnection queue and general interest, the study assumes that a large percentage of the generation that will develop in the study region will be wind-energy generation. The specific wind and non-wind generation projects that develop in the region will be highly dependent upon a variety of factors, including the requirements of Open Access Transmission Tariffs (OATT's) such as the Midwest ISO's tariff. However, for purposes of this study it is assumed that wind-energy generation is the primary source of generation developed.

Process

The CVS evaluated combinations of previously proposed transmission projects on a common basis, with a common model and common set of assumptions, and then estimated the range of possible generator outlet capability created by each of these combinations. The study evaluated the regional utilities transmission expansion plans. This included projects that are under consideration and the estimated outlet capability is of projects and combinations of projects that have been proposed. The study team chose to focus on 24 of the most likely transmission project combination scenarios.

The CVS conducted steady state analysis to examine the transfer of power from the assumed source locations to the assumed sinks in order to test various combinations of planned transmission projects. Due to the large number of scenarios examined and the relatively large footprint being studied, the study used a combination of AC and DC solution methods. Facilities were monitored

[1] CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure continued reliable and affordable service. The new transmission lines support local reliability, regional transmission system support and allow additional generation outlet.

under both system normal and during contingencies. The study team used commonly accepted screening methodology to determine significantly affected facilities. The study established 'stopping criteria' to determine the point at which underlying system upgrades become so great that something larger should be built instead of just fixing the individual system elements as they reach their limits.

Since the CVS was a vision-type study, only steady state thermal analysis was completed. This was done because of the large number of scenarios simulated. Further analysis will need to be conducted to obtain more detailed and precise results, including stability analysis, loss analysis, operational analysis, in depth voltage and var analysis, and optimization of project configurations.

Capacity Validation Study Findings

Sink Observations

One of the most significant findings of the analysis is that vastly different amounts of power transfer capability are observed depending on the location of the sink assumption used. After evaluating a number of different sink locations, the results show that in general, sinking to the Midwest ISO footprint provides the least amount of transfer capability. Sinking to the Northern MAPP sink provides the most transfer capability. Sinking to the Twin Cities area provides capability somewhere in between these two bookends. This report discusses the pros and cons of each of the sink scenarios and the scenarios' applicability to generation and transmission development.

Priority Transmission Projects

Based on the results of the various sinks and transmission scenarios, the analysis concludes that three projects should be the focus of the utilities' transmission expansion efforts after the development of the CapX2020 Group I lines. These next projects are a La Crosse – Madison 345 kV line, upgrading the Southwest Twin Cities - Granite Falls 230 kV line to a double circuit 345 kV line and possible Upsizing Group I to 345kV double circuit, depending on the total amount of generation that is needed to be developed. Individually and in combination, these three transmission projects provide the most transfer capability across a variety of underlying assumptions. These projects appear to provide the next largest increment of transfer capability at relatively low cost, thus providing the most value to the system.

Another finding of the study is that the CapX2020 Group I projects appear to provide more outlet capability than had previously been assumed. This increase in outlet capability is due to the projects being studied on combined basis rather than on an individual, standalone basis. The combination of transmission provides more transfer capability. The effort to move these projects through the regulatory and construction processes should continue as scheduled. Each of the CapX2020 Group I projects should also be built with the capability to be double circuited (upsized).

The Corridor project should be the next project pursued in Minnesota for wind transfer. The CVS results indicate the Corridor project provides the most transfer capability to the Twin Cities sink at a low cost. The Corridor also provides the most benefit to transfers off the Buffalo Ridge where there is the greatest interest in interconnecting new projects. The 230 kV line between Granite Falls and Blue Lake has been shown to be the next major limiter for large amounts of energy transfers from western and southwestern Minnesota. However, due to the high utilization of the line, it is not possible to remove the line from service for an amount of time sufficiently long enough to upgrade the capacity of this line. After the Brookings County – Twin Cities line is completed, it would be possible to take the Corridor line out of service for construction, but the construction window is limited before the Corridor line is loaded back up again with more wind generation. If the Granite Falls – Blue Lake 230 kV line were taken out of service to be upgraded without a parallel line in place before the outage, existing generation in western Minnesota, North Dakota and South Dakota would be severely limited throughout the duration of the outage.

The CVS shows that double circuiting the Group I projects allows for more transfer capability than the originally proposed single circuits. The double circuiting of the Fargo – Twin Cities line allows for more generation development in the northwest as well as redirecting existing system flows down the Fargo – Twin Cities line rather than through the Buffalo Ridge Area. The redirection unloads the lines on the Buffalo Ridge and thus allows for more development in the Buffalo Ridge area. The double circuiting of the La Crosse – Twin Cities line would, in conjunction with the La Crosse – Madison Area line, direct more flow down that path to the Midwest ISO market. When considering study work conducted for the CapX2020 Group 1 Certificate of Need, it may not be possible to utilize the transmission capability created by the Upsizing of Group 1 until after the Corridor Upgrade is in place.

Further results of the CVS indicate a new transmission line is needed east of Minnesota. In nearly every transmission scenario which sinks to the Midwest ISO footprint, the King – Eau Claire line emerges as the limiting element. The only scenario in which this line is not the limiting element is when a parallel line exists between La Crosse, Wisconsin and the Madison, Wisconsin area. From the study results, each scenario which contains a new La Crosse – Madison line provides more transfer capability when sinking to the Midwest ISO than any of the scenarios without this new line. The CVS examined the line as a single circuit 345kV only, but it is possible a double circuit line would be justified[2].

500 kV Line

Issues surrounding the 500 kV line need to be explored further. Portions of the 500 kV system were shown throughout the CVS as reaching their existing limits. The 500 kV system has the potential to be upgraded to a higher capacity by upgrading the series capacitors on the line as well as adding more transformation capacity and with some other minor equipment upgrades. These upgrades have relatively small dollar costs, however there are several other issues surrounding the line that would need to be resolved prior to the utilization of the increased capability of the 500 kV system.

RES 2016 Goals Realized

Based on the results of the CVS, with the CapX2020 Group I transmission lines in place, and the Southwest Twin Cities – Granite Falls double circuit 345 kV line in place, the MN RES 2016 goals are expected to be met. This assumes the planned transmission projects can be permitted and constructed in a timely fashion. Each of these transmission projects has an in service date or potential in service date before 2016 according to the most recent schedules. A La Crosse to Madison area line may also be needed, but an operational study is necessary to fully evaluate how the regional transmission system is able to handle the 2016 RES level of wind.

Capacity Validation Study Associated Observations

The results presented in the Capacity Verification Study are all based on a specific set of assumptions which drive the results observed. Should any of the assumptions change, such as source location, sink location, or exact transmission configuration, the results of the study will change.

The CVS was meant to be a high level visionary study to help the utilities decide where to focus their effort in transmission needs in the near term and to validate the findings of previously completed studies. While care was taken to develop reasonable assumptions, the assumptions are subject to change.

[2] More studies would be needed to see if a single or double circuit line is more appropriate, as well as what the ultimate end point should be – Columbia or West Middleton.

II. Introduction

This report is a summary of the analysis undertaken in the Capacity Validation Study. The Minnesota Renewable Energy Standard (RES) has become the most significant driver to expand the transmission network in the upper Midwest. Essentially, load serving entities will need to obtain in the range of 4,000 – 6,000 MW of nameplate wind energy generation by 2025. Should other forms of renewable energy be procured, the nameplate MW requirement could be reduced. However, given the pattern of renewable generation interest in the region, it is generally assumed the vast majority of qualifying renewable energy will be wind generation.

In order for load serving entities to fulfill that requirement, significant transmission infrastructure will need to be constructed in order to assure that a robust and reliable system is maintained after addition of that generation. Several transmission projects are either under construction, being permitted, being proposed, and/or being studied that address the need to develop a robust and reliable network that will be available for Minnesota load serving entities to develop all the generation they need to serve their customers, including generation to satisfy their RES requirements. Even though technical studies have been completed for each of the transmission projects individually or in combination with only a few projects together, such as through the CapX2020[3] Vision Study, a thorough technical evaluation of all transmission projects in combination has not been performed.

This study focused on the impact specified transmission projects, either taken individually or in combination, has on the ability to incorporate additional generation into the system. The results of this study will provide an estimate of how much additional generation could be added by these various combinations of projects with the assumed generation locations. This information will provide load serving entities and generation developers additional information on their ability to deploy generation in the future, including the requirement that they comply with the RES. This study also sought to verify and validate the transfer capabilities estimated by the other project studies.

This study is part of the extensive effort undertaken by Minnesota Transmission Owners (MTO) to assess the transmission system in the upper Midwest for improvements necessary to develop a robust and reliable transmission system that (i) allows the development of generation projects that satisfy the Renewable Energy Standard legislation milestones, (ii) continue to enable reliable, low cost energy for our region, and (iii) continue developing a robust and reliable

[3] CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure continued reliable and affordable service. The new transmission lines will be built in phases designed to meet this increasing demand as well as to support renewable energy expansion.

transmission system.   Transmission Planning studies tend to fall into two broad categories: vision studies and Certificate of Need studies. Vision studies take a high level, indicative look at the transmission needs; a Certificate of Need study is a more thorough analysis of the transmission system and is required by regulators to move forward to the next steps of constructing a large-scale transmission system improvement. The CVS is considered to be a vision study.

The CVS, Corridor Study, and RES Update Study, among other study efforts are proceeding simultaneously to examine the transmission system impacts as new generation comes online. Since each study has a unique focus, the study teams have examined the cumulative transmission system under different assumptions, with different potential projects, and with different purposes for the various studies. The studies do not precisely mirror one another with regard to generation outlet, limiting facilities, or possible solutions, and this is typical of transmission planning work. As assumptions change among various studies, the results will also change. The most important things to watch for when examining the wealth of study work being completed are trends that develop in the data. For example, when multiple studies with varying assumptions suggest significant outlet can be created with a particular project (or set of projects), this presents a reliable indication that completing the project will result in outlet capability within these general ranges.

It is important to note that this validation study's focus was on transmission planning, the costs of transmission projects, and the level of generation that might be enabled by identified transmission upgrades. Based on the Midwest ISO generation interconnection queue and general interest, the studies assume that a large percentage of the generation that will develop in the study region will be wind-energy generation. The specific wind and non-wind generation projects that develop in the region will be highly dependent upon a variety of factors, including the requirements of Open Access Transmission Tariffs (OATT's) such as the Midwest ISO's tariff. However, for purposes of these studies it is assumed that wind-energy generation is the primary source of generation developed. These studies focused on the transmission solutions necessary to enable generation development, including wind-energy generation, in the study area.[4]

[4] Note that the actual cost to consumers of new generation is represented by the total of three very distinct factors: transmission cost, production cost, and integration cost. Transmission studies generally take a high-level partial look at production cost but further analysis is necessary to determine the actual production cost impact. These studies did not attempt to address the integration cost. This is the cost incurred to operate the grid reliably with significant levels of wind integrated into the grid. To understand the total cost implication of implementing transmission development assuming specific wind integration plans, additional analysis is required.

A. Background

A robust transmission system needs to be in place to support generation development. The effective growth of renewable energy development is also highly dependent upon the presence of a robust and reliable transmission system. In Minnesota, high potential wind resources used for energy production are located far from the load centers where the majority of energy is consumed. The distance from likely generation sources to Minnesota's load centers also contributes to the need for a robust and reliable transmission system.

Going back a decade or more, the transmission studies to enable wind delivery were focused on the Buffalo Ridge area in southwest Minnesota where many wind generation projects were planned and have been built. The first significant transmission project focused on enabling wind generation development was a series of smaller transmission system improvement projects (the 425 Project) that provided system support for the development of 425 MW of wind generation capacity in the Buffalo Ridge.

The next major transmission project was designed to increase generation outlet from the Buffalo Ridge to 825 MW (the 825 Project) It included several smaller transmission projects and one 345 kV line in southwest Minnesota from Split Rock near Sioux Falls, South Dakota to Lakefield Junction, Minnesota. The 825 Project provided system support for increasing wind generation capacity in the Buffalo Ridge to approximately 825 MW.

Then, the BRIGO (Buffalo Ridge Incremental Generation Outlet) Project planned three new 115 kV lines in the Buffalo Ridge area and some 345 kV substation upgrades. The BRIGO series of improvements raised the Buffalo Ridge generation output to about 1200 MW.

The most recent Buffalo Ridge area study was the Brookings County, South Dakota – Hampton, Minnesota 345 kV line. This line is one of the CapX 2020 Group 1 projects and is currently being permitted. It is planned to run west to east through southern Minnesota and will increase the Buffalo Ridge generation outlet capacity to approximately 1900 MW.

Through these projects, a general trend has been observed that the more the transmission grid is improved, the more incremental output each project makes available for wind generation capability. Each addition to the transmission system tends to add much more capacity as an incremental part of the greater transmission system.

Around the same time Brookings County – Hampton 345 kV line was studied, the Red River Valley / West Central Minnesota Transmission Improvement Planning Study (TIPS) and the La Crosse/Rochester load serving studies were also occurring. These three studies were conducted individually and with the exception of the Brookings line, were focused on system reliability rather than generation outlet. These three studies recommended new 345 kV and 230 kV transmission lines similar to what was identified in the CapX2020 Vision Study and have since become the CapX2020 Group I projects.

Currently, there are several transmission studies being conducted by the MTO and others which are evaluating ways to provide a robust and reliable transmission system sufficient to allow load serving entities to comply with the various states' RES requirements. Most of these studies are high level vision studies which are looking at 765 kV and 345 kV options to transport large amounts of generation from the heart of the Midwest to the load centers further east. A few studies are being conducted which would specifically impact Minnesota's ability to meet its RES requirements. The Corridor Study examines the system benefits of upgrading the existing Minnesota Valley – Blue Lake 230 kV line to double circuit 345 kV from Hazel Creek – Blue Lake. The RES Update Study is a vision level study that examines additional transmission projects that will be necessary for utilities to satisfy the 2020 RES and beyond milestones. Midwest Independent Transmission System Operator (Midwest ISO[5]) is also evaluating a line from La Crosse to the Madison, Wisconsin area which may also have an impact on transfers from Minnesota to the rest of the Midwest ISO market.

Currently there is a joint transmission planning study underway to determine the need for a new transmission line from La Crosse, Wisconsin to an endpoint in the Madison, Wisconsin area. The study is addressing the long term load serving support for the western portion of Wisconsin. This study is being led by American Transmission Company (ATC) with participation from other area utilities, including MTO members Xcel Energy, Great River Energy, ITC Midwest, Southern Minnesota Municipal Power Agency, and Dairyland Power Cooperative. Completion of the study is expected by the end of 2009 with a potential in-service date before 2016. This study may also have an impact on transfers from Minnesota to the rest of the Midwest ISO market.

B. Summary of the Study Scope

The scope of the CVS was to evaluate combinations of future transmission projects on a common basis and estimate the range of possible generator outlet capability created by each of those combinations. This was done by evaluating the various combinations of projects using a common model and common set of study assumptions. In this way, the project combinations could be compared on an equal basis. This study also sought to validate the regional utilities

[5] Midwest ISO is a not-for-profit member-based organization of electric transmission owners, covering a 15 state region from the Dakotas to Pennsylvania. Midwest ISO administers and manages the transmission of electricity within its region.

transmission expansion plans both as to which projects are pursued and as to what the estimated outlet capability is of the various projects and combinations of projects.

C. Uncertainties

Uncertainties affecting the outlet capability and results of this study include the following:

- Uncertainty of generation location – The study team used the best information available at the time of the study. This study used one set of generation location assumptions and provided a possible range of delivery capability. However, as actual generation is sited in varying locations, this range may be subject to change.
- Generation Interconnection Process – This study work is neither intended to replace the interconnection process of the Midwest ISO or any other transmission provider nor is it intended to provide a guarantee of interconnection should a generation project seek to interconnect in a particular location. Specific generators, even those seeking to interconnect in locations at which generation was assumed in this study, will still be required to move through the interconnection process.
- Transmission Cost – Cost estimates for the project were completed using 2007 dollars. Prevailing market conditions could change these estimates due to cost of materials, competitive bidding for crews, and other expenses.
- Amount of generation needed – The study was conducted assuming a target amount of wind generation needed to meet the Minnesota RES based on the MTO Gap Analysis[6]. If one were to assume that new generation added in Minnesota, North Dakota, and South Dakota were being used to meet renewable energy requirements of other states, then there would be less generation outlet available for the Minnesota Utilities to meet the Minnesota RES requirements.
- Higher voltage system overlays – There are multiple study efforts under way to look at building a 500 kV, 765 kV or HVDC transmission system to transfer power across larger distances. These overlays would have the potential to affect the overall system flows and biases and could change the results of this study.

[6] The original Gap Analysis was conducted by the MTO for inclusion in the 2007 RES Report and calculated the amount of wind energy (in MW) that would be necessary to meet each RES milestone statewide and for each company. The RES Report was required by the 2007 Next Generation Energy act and was filed in conjunction with the 2007 Biennial Transmission Projects Report. A full version of the report can be found on the web at http://www.minnelectrans.com. A clarifying filing with additional detail can be found at This filing can be found at:https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5497544

- Other generation types – The focus of this study was based on wind development and did not take into account other generation needs (base load, peaking, geothermal, solar, etc.) which could be built in the timeframe of the study. The development of these other generators would be alternative forms of renewable generation or may be needed to meet capacity and reliability requirements and would affect the estimated outlet capabilities. Ultimately, the transmission system must be developed to accommodate the addition of all generation that seeks to be added to the system in accordance with the Midwest ISO's tariff requirements or any other applicable transmission provider's Open Access Transmission Tariff.

Recognizing these uncertainties, the study team presents their findings (outlet capability achieved, dollars, timing) in terms of ranges.

D. Legislation

The state of Minnesota has legislative and regulatory requirements that mandate Minnesota's load serving utilities take significant actions to enable substantial growth in the development and use of renewable electricity. Minnesota's Next Generation Energy Act of 2007 enacted the Renewable Energy Standard (RES). The RES requires that 25 percent of the electricity consumed in Minnesota be generated by renewable resources by 2025. This enabling legislation provides interim milestones beginning in 2010 through 2025 with specific renewable energy goals for utilities to use to set a plan in place to meet these objectives. Additionally, the RES requirements hold Xcel Energy to a higher standard, requiring 30 percent of its customers' electricity needs with renewable sources by 2020. Table 1 below shows the renewable energy requirements for each milestone year and the full text of the Next Generation Energy act can be found at https://www.revisor.leg.state.mn.us/bin/bldbill.php?bill=H0436.0.html&session=ls85

Table 1: Renewable Energy Standards - Percent of Annual Minnesota Retail Sales to be met with Renewable Generation

Year	Utility Requirement	Xcel Energy
2010	7%[7]	15%
2012	12%	18%
2016	17%	25%
2020	20%	30% - 25% must be wind
2025	25%	30% - 25% must be wind

Another part of Minnesota's Next Generation Energy Act of 2007 requires Transmission Owning Utilities to analyze and identify specific transmission solutions for serving the renewable energy resources necessary for the load

[7] The 7% milestone in 2010 represents a good faith objective for those utilities that do not own a nuclear generation facility in the state of Minnesota.

serving utilities to comply with the expanded and accelerated renewable energy standards. The MTO responded with a well-thought-out strategy sponsoring a series of studies that describe the planning steps necessary to meet the transmission needs of the expanded renewable energy standard objectives. The MTO must examine how the complex interconnected electric grid needs to be built in order to support these ambitious milestones and continue to provide a robust, reliable and cost-effective transmission system that will allow load-serving entities to continue providing reliable and cost effective electric service. The CVS, Corridor and RES Update studies are three of the studies that are intended in part to meet the goals.

E. Schedule

The CVS was first envisioned in early October, 2008 as a very high level analysis with a completion goal of the beginning of November. As the scope was developed and then expanded, the end dates were revised to December 31, 2008 and eventually March 31, 2009 to provide more time for the more detailed scope completion. This also coincided with the close of two other MTO studies, the RES Update and Corridor Studies.

October 14, 2008 – The lead utility representatives identified the study team and led a Study kickoff meeting with key participants.
Mid-October to Mid-November, 2008 – The study team developed the initial model.
November, 2008 – Simulation testing.
December, 2008 – Phase I, Part 1 & 2 analysis ran simulations of the maximum interface levels, all sources together and in the geographic pockets.
January through February, 2009 – Phase II, Part 1 & 2 analysis ran simulations of the historical Interface levels, all sources together and in the geographic pockets.
March, 2009 – Report writing

F. Regulatory Context

Electric generation and transmission service is a regulated industry. Care was taken during this study to follow all appropriate regulations. For example, commercially sensitive, non-public market information was handled correctly as related to U.S. Federal Energy Regulatory Commission (FERC) Order 2004 regulations concerning the separation of transmission and resource planning efforts. These standards of conduct are in place to prevent anticompetitive practices between electric transmission providers and their marketing affiliates.

Transmission-owning utilities are subject to an OATT are required to provide transmission service on an open-access and non-discriminatory basis. Thus, the MTO does not prejudge and cannot preclude any particular generation source from transmission access. The transmission facilities contemplated by these studies will be available to all generation sources; however, based on generator interest and the Midwest ISO or other transmission provider's interconnection queue, it appears likely that wind-energy generators make up the substantial majority of likely generators who will use the transmission capability enabled by these facilities.

The study was undertaken in accordance with the North American Electric Reliability Corporation (NERC) Planning Standards. NERC is certified by FERC to be the organization to develop and enforce reliability standards for the bulk power system. The United States electricity industry operates under mandatory, enforceable reliability standards. Utilities and other bulk power industry participants must follow these standards or face fines and other sanctions. The standards describe how reliable systems need to be developed to meet specific performance requirements under normal conditions (TPL-001 or Category A); following the loss of a single bulk electric system element (TPL-002 or Category B); and following the loss of two or more bulk electric system elements (TPL-003 or Category C). The study's modeling and analysis followed the standard requirements. Details on NERC standards can be found at http://www.nerc.com/page.php?cid=2|20.

III. Models and Assumptions

One of the most vital steps to ensure meaningful output from the study process is to develop an accurate model of the Minnesota transmission system and the greater integrated electric transmission grid for the study timeframe. Great care was also taken to define accurate assumptions of how the system will be built and operated.

The transmission system in Minnesota and the upper Midwest is a complex network of high voltage bulk transmission lines that transfer power from generation to load centers, lower voltage lines that distribute power among the load centers, and still lower voltage lines that deliver power within cities and to end-use customers. Utilities in Minnesota have a long history of developing projects jointly for mutual benefit. This extends to the study process and the models that are used as inputs to the development of any projects in the state. A concerted effort to produce a model that accurately represented each of the utilities in the state was necessary in order to ensure the integrity of the study work being performed. An example of the complexity of the transmission system model in Minnesota is shown in Table 2 below, which gives the number of miles of transmission line currently in service in Minnesota.

Table 2: Miles of Transmission Line in Minnesota[8]

	<100 kV	100-199 kV	200-299 kV	>300 kV	DC	Total
Miles	8,604	4,728	1,895	1,193	436	16,856

Since the focus of this study was to examine wind transfer capabilities, and the study team had a limited timeframe to complete the analysis, the decision was made to only look at an off-peak energy load scenario. Wind is more likely to be at peak output during the off-peak energy load scenarios than an on-peak energy load scenario, which is the basis for this decision.

A. Base Model

Due to the short timeframe to perform the study, it was the choice of the study team to use a previously developed and well-documented model. The team decided to use the base model that was developed for the RES Update and Corridor Studies. Below is a discussion of the discrete steps the study team performed to achieve the transmission and transmission substation modeling effort.

2016 Transmission System – Base Model Development for RES Update and Corridor Studies (which was the starting model for the CVS)

2016 was chosen as the year to study and model the transmission system. The in-service date planned for the conversion of the Southwest Twin Cities – Granite Falls Transmission Corridor is currently the end of year 2015. This provides the added transfer capability currently anticipated to be necessary to support generation projects in that time frame. It is also anticipated to be sufficient for Minnesota's utilities to enter into generation projects that satisfy the State of Minnesota's Renewable Energy Standard goal through 2016.

<u>Steady State Transmission System Model</u>

The first step to build the steady state transmission system model was to take data from a known and widely accepted model from the Midwest ISO Transmission Expansion Plan 2007 (MTEP07). MTEP07 developed a model series encompassing the entire Midwest region's transmission system as well as future transmission expansion plans. It was released by the Midwest ISO in 2007 and provides a series of models that include models for years 2013 and 2018 years. This 2013 model from MTEP07 is the best topology available for Midwest ISO members and is the model employed in other RES studies, and the DRG Studies. The model is suitably documented and well understood.

MTEP07 created 2013 and 2018 peak and off-peak models. Since the study team needed to look at a 2016 timeframe, the team chose to average the loads of the 2013 and 2018 models to create a 2015 ½ load level for study of the year

[8] Approximate mileage as of November 1, 2007.

2016. In this manner, half a year of load growth was built in as a proxy for the impact of the Minnesota Energy Conservation Improvement Plan (CIP) energy conservation assumptions. In the off-peak case, the study team chose a 61% load level that is used to model a typical off-peak summer load with the highest system transfers.

One limitation of the MTEP 07 model series is the fact that it includes only the Midwest ISO member utility data. There are utilities in this region (and members of the MTO) that are not Midwest ISO members. To ensure the model was inclusive of Midwest ISO member utility information as well as non-Midwest ISO member utility information, the study team took on the challenging task of aggregating the two sets of data. The non-Midwest ISO member data was obtained from the Midwest Reliability Organization (MRO). The MRO is one of eight regional reliability organizations in North America that operate under authority from the US and Canada whose focus is ensuring transmission reliability compliance. The MRO builds the models of the utility facilities in this region including those utilities that are not members of the Midwest ISO. The MRO models were available in 2012 and 2017 versions. A 2015 ½ load level was also created from this initial data set.

Another reason the Midwest ISO MTEP 07 model series was the initial model to build upon was because the study team needed the eastern part of the Midwest ISO footprint to be included in the models for the analysis scenarios in which generation was sunk to the Midwest ISO-wide market.

The next step, transplanting this non-Midwest ISO (MRO) data into the Corridor and 2016 transmission system model, also proved to be quite challenging. Since the study team was using a simulator program called the PSS/E (Power Systems Simulator for Engineering) inputting accurate phase angles was key since they help set the power transfers across lines and transformers. If there is too much difference between a non-transplanted bus and its adjacent transplanted bus, the case will not solve. A bus is a physical electrical interface where many transmission devices share the same electric connection. Each time a MRO area is transplanted into the MTEP, the MISO model then has to be "nursed" into solving. There is also a possibility that during this process, duplicate or fictitious facilities can be created since bus numbers between models can be inconsistent. Therefore, the model with transplanted information was reviewed for accuracy.

Another detail that complicated the task of transplanting the data was the varying way three-winding transformers are treated in PSS/E. In some instances the three-winding transformers have a PSS/E's built-in construct for such transformers. In other models, the three-winding transformers are depicted the historic way with three explicit branches. Still other three-winding transformers omit the third winding entirely and use PSS/E's construct for two-winding transformers. Therefore, the transformers had to be reviewed for correctness.

CVS Base Transmission Updates

Starting with the Corridor and RES Update model, which was developed as described above, several other modifications were made to create the base case for the CVS. To start with, all generation and transmission projects with an in-service date of 2012 or later were removed from the model. The rationale behind this was to only have facilities in the model which have a high level of certainty to be installed.

Recently completed and future transmission upgrades that were included in the model are as follows (These are transmission projects that at the time this analysis was started were expected but not guaranteed to be in-service by 2012. The projects are in various stages of permitting and construction.):

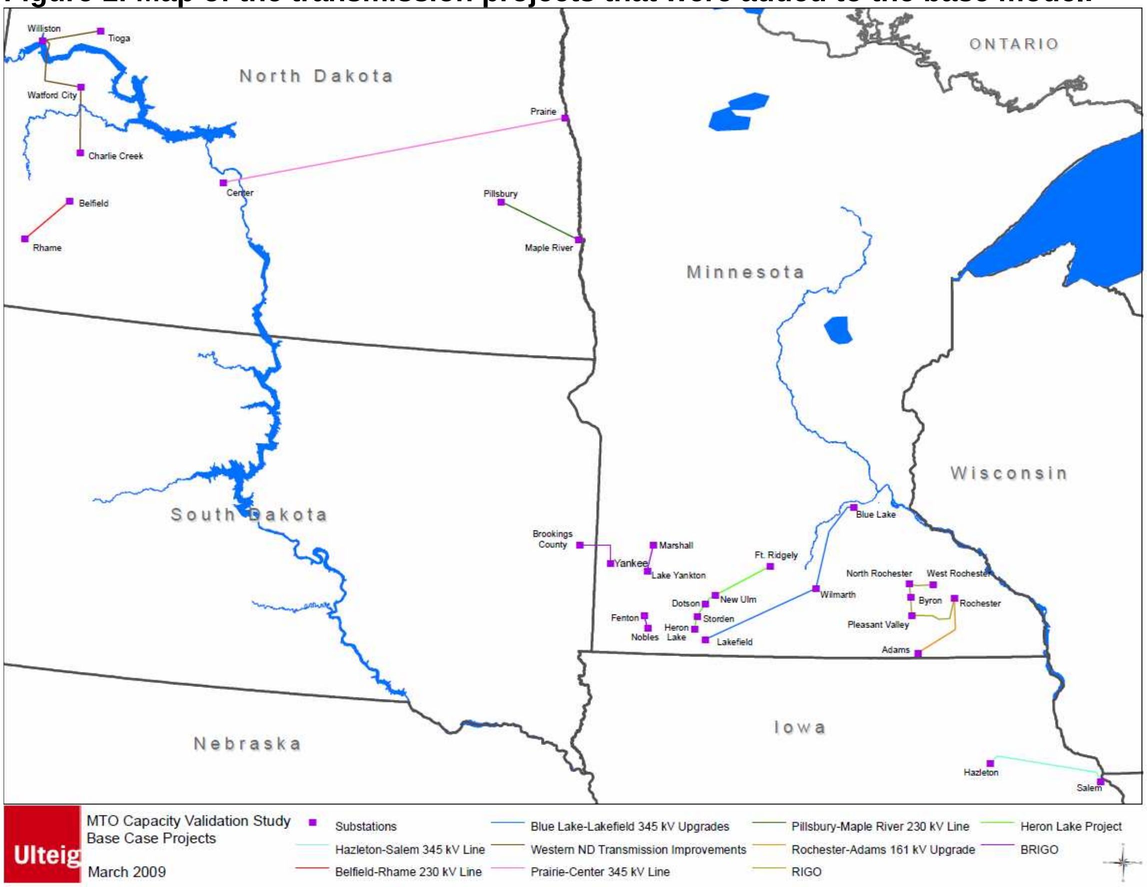
- Transmission projects identified in section III of the MTO's September 11, 2008 response to Docket E999/M-07-1028[9]
  - Pillsbury – Maple River 230 kV
  - BRIGO
    - Marshall – Lake Yankton 115 kV line
    - Yankee – Brookings County 115 kV circuit 2
    - Brookings County 115/345 kV Transformer #2
    - Fenton – Nobles 115 kV circuit 2
    - Nobles 115/345 kV Transformer #2
  - Blue Lake – Wilmarth – Lakefield 345 kV equipment upgrades
  - Center – Arrowhead DC line purchase by MP (along with the Center – Prairie or Maple River 345 kV line)
  - Rochester – Adams 161 kV upgrade
  - RIGO
    - Pleasant Valley – Byron 161 kV
    - Pleasant Valley – Rochester 161 kV line
    - Byron – Rochester 161 kV line
    - Pleasant Valley 345/161 kV Transformer #2
  - Heron Lake Project
    - Heron Lake – Storden – Dotson 161 kV line
    - Dotson – New Ulm – Ft Ridgely 115 kV line
- Hazelton – Salem 345 line
- Western ND transmission improvements
  - Additional Oil load
  - Tioga – Williston – Watford – Charlie Creek 230 kV line
  - Belfield – Rhame 230 kV line

The study team also added all of the transmission projects to the base model which were to be the focus of the study, but initially these projects were left out of service in the base model. This was done to facilitate automation of the study effort, so the study team could create the various transmission scenarios to be

[9] This filing can be found at:https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5497544

investigated by the study. To create a specific transmission scenario one or more projects are switched in or out of service, rather than having to add or delete all of the facilities associated with the various projects comprising the transmission scenario. The specific transmission scenarios and projects studied are described later in the report.

Figure 1: Map of the transmission projects that were added to the base model.



Base Case Generation Updates

The study team verified that most generation units that were existing or under construction, as of the start of the study[10] (October 2008), were included in the base case. Based on the Midwest ISO Generation Interconnection Queue and the need for load serving entities to comply with the RES, the main focus of this effort was on wind projects in the study footprint. Because of the significant amount of wind that was included in the model, it was not as important to ensure peaking units were included in the model. In a merit order economic dispatch, the new wind would be displacing thermal peaking generation; therefore any new peaking unit would already be offline. Merit order of generation is the operational methodology of turning down more expensive generation when the new (typically

[10] The study team used information found on the American Wind Energy Association website (AWEA) to identify existing and under construction projects. www.awea.org

less expensive) generation is ramped up on the system. Below is a summary of the amount of wind generation that was included in the base case by state (see Appendix B for a complete list):

- Minnesota – 1774 MW
- North Dakota – 1361 MW
- South Dakota – 91 MW
- Iowa – 1355 MW
- Wisconsin – 575 MW
- Manitoba – 99 MW

Dynamic Models

This study did not evaluate system stability, so there was no need to develop a dynamics model.

B. Assumptions

Generation Dispatch

In the past, delivery capability studies have been completed on an incremental basis. This means a study for a new transmission project relied on the results and assumptions of previous studies. Table 3 below is an example of this. Each incremental study would make an assumption as to where generation would be developed in order to use the capability created by previously studied projects. This study however, took a different approach by only placing existing or under construction wind generation into the base model and did not make any assumptions as to where wind generation would be developed to use the incrementally created capacity.

Based on the table below and considering the facilities that are included in the base model, namely BRIGO and RIGO, one could estimate that the wind generation outlet capability of Minnesota is about 1900 MW in the basecase. Currently, Minnesota has a little less than 1800 MW installed or under construction which was included in the base model and is relatively close to the estimated 1900 MW capability of the system[11].

[11] This isn't an apples to apples comparison, due to the previous transmission projects being designed for firm outlet (NR) and this value includes both firm and non-firm interconnections (ER and NR).

Table 3: Sample Transmission Projects & Incremental Wind Generation Outlet Capabilities

Prior Amount of Renewable Generation	Project	Addition	New Total
265 MW	425 Wind project	160 MW	425 MW
425 MW	825 Wind project	400 MW	825 MW
825 MW	BRIGO	375 MW	1200 MW
1200 MW	Twin Cities – Brookings CapX 2020 project	700 MW	1900 MW
1900 MW	RIGO	700 MW[12]	2600 MW

All of the wind generation identified as being online or under construction was dispatched to its nameplate capacity in the base model. The wind projects identified include both Energy Resources (ER) and Network Resources (NR). All wind was treated equally as the goal of the utilities is to meet the RES requirements regardless if a project has ER or NR status. Because generation and load (plus losses) always needs to be in balance, thermal generation was turned off as wind generation was turned on. This was done on a merit order basis, where essentially all peaking generation in the Northern MAPP (Mid-continent Area Power Pool)[13] area was turned off so the wind units could be on at peak output. The exception to this was the Lakefield, Pleasant Valley and Angus Anson generating units. These units were left on at full output [14]as they are located close to areas with high wind development and the transmission rights of the units need to be preserved.

The transmission system has been developed allowing for various levels of transmission rights. This is commonly referred to as firm and non-firm transmission rights or NR and ER transmission service. Transmission customers with firm or NR service have priority to the transmission system and are allowed to schedule their transactions under normal circumstances with the potential to be curtailed only under emergency situations. Non-firm or ER service customers only have rights to the transmission system on an as available basis and are subject to curtailment prior to curtailment of customers with firm or NR service. A transmission customer has the option of taking whichever form of service it chooses based on the system upgrades that may be required and the level of curtailment risk they are willing to accept.

[12] This is an example of changing study assumptions. The RIGO study originally estimated approximately 922 MW of outlet capability created. Since that time the RIGO project has been refined, and this outlet level has since been reduced to 700 MW.

[13] MAPP (Mid-continent Area Power Pool) is an association of electric utilities and other electric industry participants for the purpose of pooling generation and transmission.

[14] The combined output of the Trimont and Elm Creek Wind Farms and the Lakefield thermal units were limited to the firm transmission rights of the thermal units. These two wind farms were interconnected and deliver energy using the transmission capacity of the thermal units at Lakefield under an operating agreement. Therefore the total output of the both wind farms and the Lakefield thermal units must always be equal to or less than the firm transmission rights established by the thermal units.

Studies are conducted such that existing customer's transmission rights are not impacted by new transmission service requests. A new transmission service or generator interconnection request is expected to keep existing transmission customers whole, by making the necessary transmission upgrades such that both the new and existing transmission service or generator can operate simultaneously without an increased level of risk placed on the existing customer. This study used assumptions and study methods in an attempt to follow this principal.

<u>Interface levels</u>

The original study scope called for the study to be conducted with the three major regional interfaces to be at their maximum limits simultaneously. This is considered to be a worst case scenario for an off-peak period and is a required scenario for evaluating interconnection and delivery studies in the upper Midwest region.

After the first rounds of simulations and analysis were complete, the study group decided that this scenario of setting the three interfaces at their maximum limits is not typical of historical operations and in fact have not reached their maximum limits simultaneously. The study team obtained hourly Interface flows from the Midwest ISO to determine a more realistic scenario for the interface levels. Table 4 shows the Peak and Minimum Interface levels and when they occurred. Figure 2 shows the flow duration curve of each of the three interfaces.

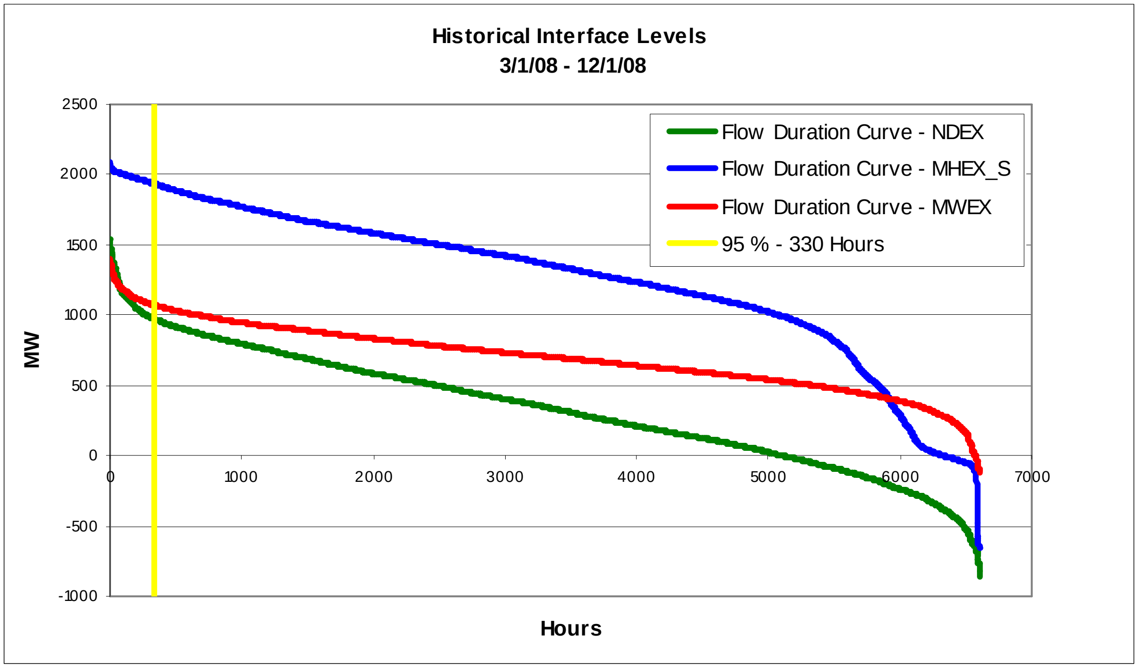
Table 4: Historical Interface Minimum & Maximum flow levels

from 3/1/08-12/1/08

Interface	Peak (MW)	Max Date	Min (MW)	Min Date	MW level 95% of Time
NDEX[15]	1542	7/12/08 4:00 AM	-857	3/9/08 9:00 AM	974
MWEX[16]	1403	6/6/08 10:00 AM	-119	3/16/08 2:00 AM	1072
MHEX_S[17]	2084	7/6/08 9:00 PM	-659	3/2/08 8:00 AM	1936

[15] The North Dakota Export (NDEX) is the sum of the flows on 18 lines that make up the "North Dakota Export" Boundary.
[16] Minnesota-Wisconsin Export (MWEX) is the sum of the flows on the Arrowhead-Stone Lake and the King Eau Claire 345 kV lines.
[17] Manitoba Hydro Export South (MHEX_S) is the stability interface of power flow out of Manitoba to the south and sum the flow on four lines between Manitoba and the US.

Figure 2: Historical Interface Levels load duration curve



After examining the historical data, the study team decided to maintain the Interfaces at a level between the maximum level and the level observed more than 95% of the time. This represents an operational scenario where one could be certain the interface levels would be less than this amount more than 95% of the time on a real-time basis. This would mean that there is a high level of certainty that new generation would be able to interconnect to the system and not have to be curtailed very often, if at all, as the probability that the interfaces are above this level and the wind is blowing at peak output would be quite small.

As mentioned previously, new generation would need to complete analysis using a maximum simultaneous interface level in both the interconnection and delivery studies. This reduced interface level scenario is an estimation of what may be possible assuming the new generation is willing to incur some increased risk of curtailment by use of a special protection scheme (SPS)[18] or runback during a limited set of system conditions. This scenario in no way implies that the high simultaneous transfer scenario is invalid, but attempt to answer the question as to how much transmission would be needed to get a majority of new generation delivered a majority of the time, rather than all the generation at all times.

To obtain the historical interface levels, the study team made adjustments to the model where the interface levels were at the simultaneous maximums. Generation levels were increased in eastern Wisconsin and the Twin Cities,

[18] A SPS is a system that is set up to trip or reduce a generator's output under certain system conditions. This generally allows a generator to connect to the transmission system with fewer transmission upgrades. Some transmission providers allow for a permanent SPS, others only allow temporary ones.

decreased at the Brandon Peaking units in Manitoba, and the load was increased inside NDEX (from 61% to 89% of Summer Peak). NDEX load was increased so that neither the wind nor base load units inside NDEX would have to be reduced in order to back off the NDEX interface level. This is due to the necessity for generation and load (plus losses) to always be in balance. Load in NDEX was scaled rather than the generation as this is the most common and accepted method of manipulating the NDEX interface level. Table 5 below shows the Interface levels used for both phases of the study.

Table 5: Interface levels used in the study

Interface	Interface Limit (MW)	Max Interface Scenario (MW)	Historical Interface Scenario (MW)
NDEX	2080	2071	995
MWEX	1525	1528	1417
MHEX_S	2175	2172	1987

The transmission models have generation units with power outputs that when combined exactly match the load in the model plus the system power losses. This balance between generation and load plus losses must always be maintained in models as well as in the real electric system. Thus, when new generation is added to the model, either the load must be increased to compensate for the new generation or existing generation must be turned down. The new generation is called the ‘source’ or the location point of the new generation and the existing generation to be simultaneously turned down to keep the system balanced is the ‘sink’. The magnitude of the ‘source’ is equal to that of the ‘sink’ plus the losses in the electrical system.

Study Sources

The study originally envisioned having one set of source generation that included potential wind sites over a rather large geographical region. These locations were based on the sources from the Corridor and RES Update studies, which took into account feedback from resource planners and the Midwest ISO Generation Interconnection Queue. After the initial set of simulations and analysis was completed, the study team ran simulations on three smaller pockets of the original sources to ensure potential issues were not overlooked by the various sources potentially counter-flowing or off-setting each other. These smaller pockets consisted of a southeast Minnesota (SE), southwest Minnesota (SW) and a central-northwest Minnesota & eastern North Dakota (NW) set of sources. Table 6 below is a listing of the sources and participation factors used in this study.

Table 6: Sources for new wind generation in the transfer analysis

Area	Source Location	Bus #	Participation (%)
SW	Yankee	60394	3.0
SW	Fenton	60393	3.0
SW	Lyon County	60171	6.5
SW	Nobles	60287	4.5
SW	Brookings	60382	9.0
SW	Granite Falls	66551	6.5
SW	Jackson	67470	4.5
SW	Split Rock	60129	5.0
NW	Big Stone	63214	6.5
NW	Karlstad	66708	2.0
NW	Inman	62531	6.5
NW	Morris	66555	4.5
NW	Maple River	66754	4.5
NW	Hankinson	63327	7.5
SE	Byron	61948	9.0
SE	West Faribault	60384	4.5
SE	Adams	34014	6.5
SE	Pleasant Valley	63070	6.5
	Total		**100.0**

The participation factor is used by MUST[19] to determine how much generation should be added or removed from any given location. For example, the Yankee bus has a source participation factor of 3%. This means that in a 100 MW transfer, 3 MW (100 MW * 3%) of generation would be turned on at the Yankee bus.

The study scope had originally called for performing the analysis using all of the sources together in the simulations. The study team decided to also look at three smaller pockets of the generation sources based on geographical location which the team referred to as the "Pocket Analysis". The three pockets were the Northwest (NW), Southeast (SE) and Southwest (SW). The pocket analysis was performed to make sure that the various sources were not counter-flowing each other and potentially masking transmission issues.

Study Sinks

The study team also looked at three different sink assumptions to assess future transmission needs. One view was to assume the power would be delivered only to greater Twin Cities Metro Area, which was represented by generating units located in the Twin Cities. The units listed for the Twin cities are considered base load units, but were used because these were the only units left on in the Twin Cities after the base system dispatch. These units are the lowest cost units that are the last to be turned off on a merit order, economic basis. The next view

[19] See Study Analysis section on Section IV A for the definition and details of the MUST software.

was to look at a dispatch option for sinking the new wind to the Midwest ISO footprint, which was represented by several Balancing Authority Areas[20] in the eastern portion of Midwest ISO. The last view was a Northern MAPP sink which was represented by base load units in Minnesota and North Dakota. Again, the units listed for this scenario are considered base load units, but were used because they were still on after the base system dispatch. Table 7 below is a listing of the sinks and participation factors used in this study.

Table 7: Sinks for new wind generation in the transfer analysis

Sink Locations	**Bus/Area #**	**Sink 1 – Twin Cities Participation (%)**	**Sink 2 – Midwest ISO Footprint Participation (%)**	**Sink 3 – Northern MAPP Footprint Participation (%)**
Black Dog	60012	5		5
Black Dog	60013	5		5
King	60006	15		7
Sherburne County #1	60000	19		9
Sherburne County #2	60001	19		9
Sherburne County #3	60002	23		9
Prairie Island	60003	14		6
Antelope Valley	67103			15
Leland Olds	67110			15
Coyote	67315			15
Boswell	61775			5
Alliant East	364		25	
Ameren	356		20	
First Energy	202		10	
Michigan Electric Transmission Company	218		20	
Wisconsin Electric	365		25	
Total		**100.0**	**100.0**	**100.0**

[20]Balancing Authority **-** The entity that maintains load, generation, and net interchange balance within a Balancing Authority Area and supports interconnection frequency in Real-Time.

Figure 3: Map of Sources and Twin Cities Sink

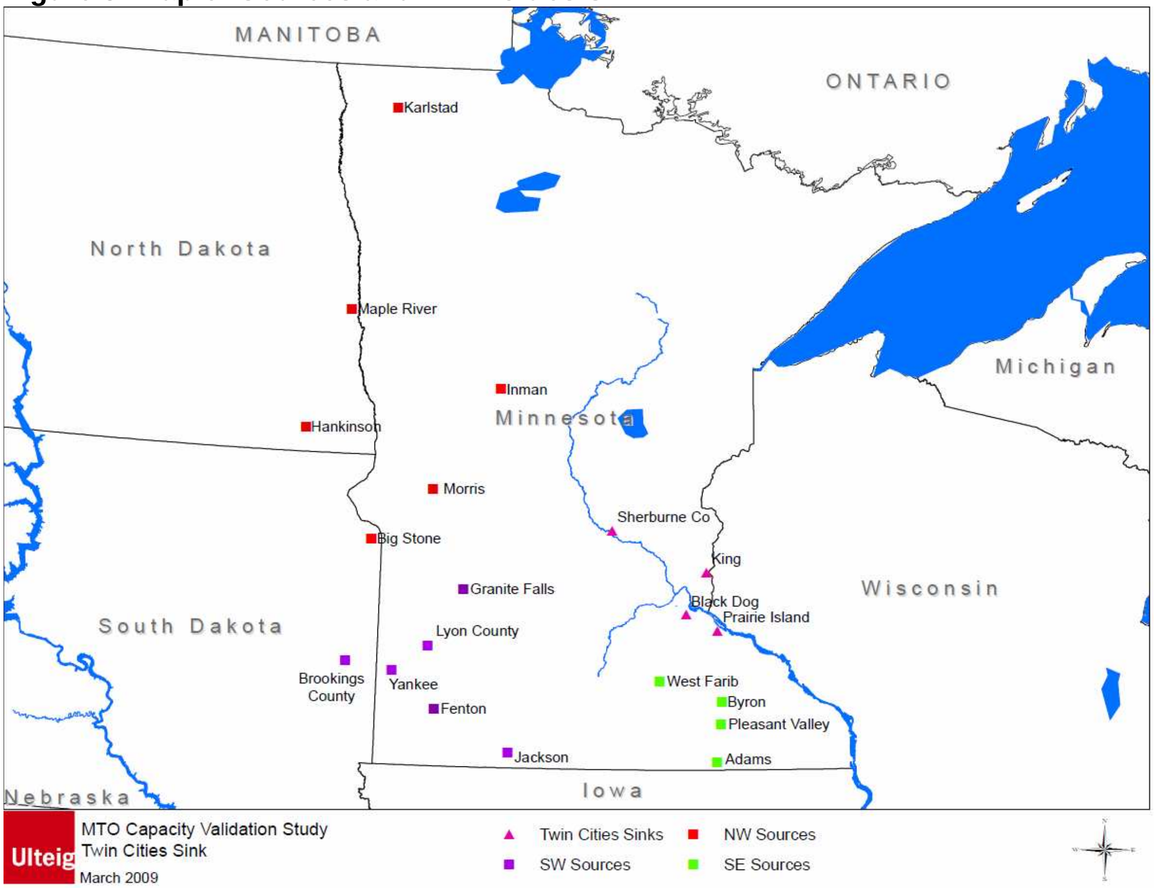


Figure 4: Map of Sources and Midwest ISO Sink

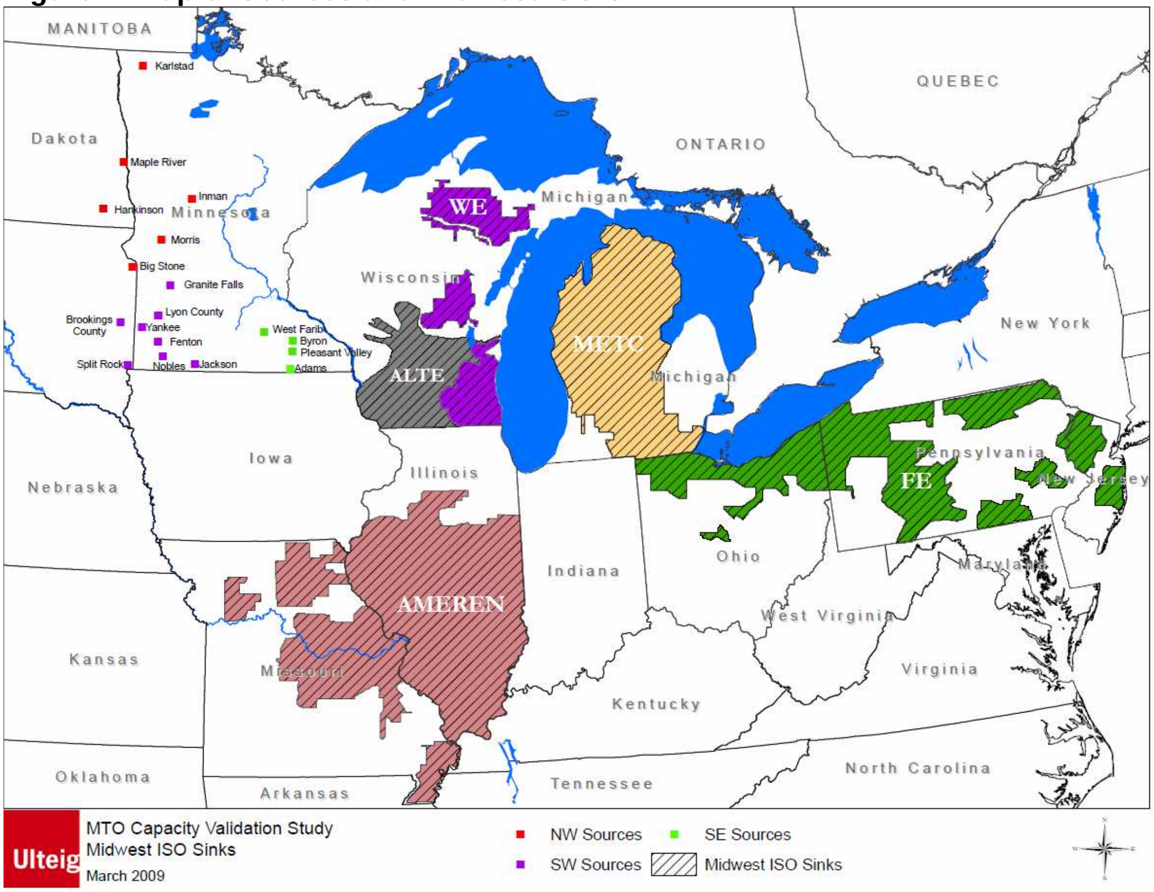
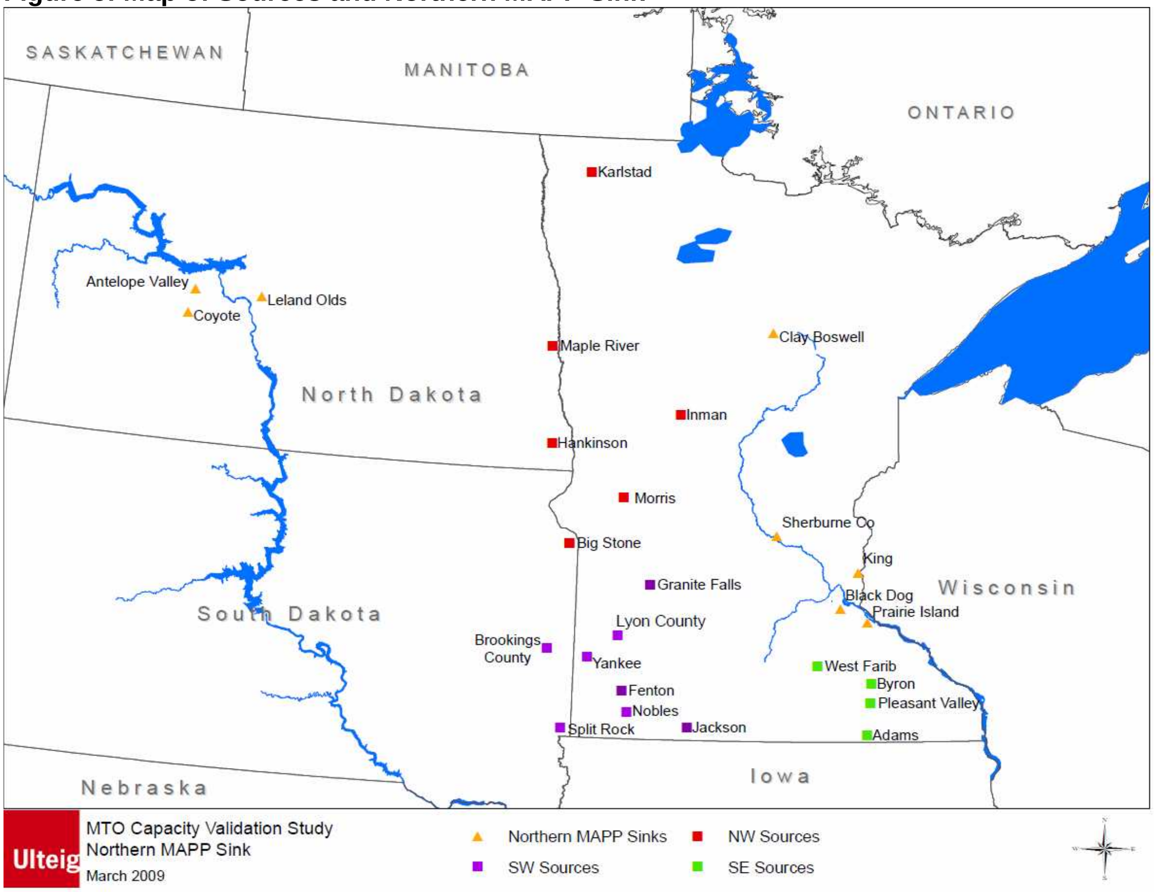


Figure 5: Map of Sources and Northern MAPP Sink



Transmission Projects Studied

The main purpose of this study was to evaluate proposed transmission projects in various combinations and to evaluate the potential range of transfer capability created by those combinations. Below is a listing of the projects, the specific facilities that make up those projects, and estimated costs for those projects[21].

1. Potential 2012 transmission configurations
   a. Base case ($0)
   b. Portions of CapX2020 Group I ($593 M)
      - Lyon County – Helena 345 kV double circuit
      - Bemidji – Grand Rapids 230 kV
      - North Rochester Sub 345/161 kV Substation
      - North Rochester – Northern Hills 161 kV
      - Northern Hills – Chester 161 kV
      - Monticello – Quarry (St. Cloud) 345 kV
2. Potential 2016 transmission configurations.
   a. Remaining portions of CapX2020 Group I ($1,139 M)
      - Brookings County – Lyon County 345 kV
      - Lyon County – Hazel Creek 345 kV
      - Hazel Creek – Minnesota Valley 230 kV
      - Helena – Lake Marion – Hampton Corners 345 kV
      - Hampton Corners – North Rochester 345 kV
      - North Rochester – La Crosse 345 kV
      - Fargo – Alexandria – Quarry (St Cloud) 345 kV
   b. CapX2020 Group I upsized ($481 M)
      - Brookings County – Lyon County 345 kV circuit 2
      - Lyon County – Hazel Creek 345 kV circuit 2
      - Helena – Lake Marion – Hampton Corners 345 kV circuit 2
      - Hampton Corners – North Rochester 345 kV circuit 2
      - North Rochester – La Crosse 345 kV circuit 2
      - Fargo – Alexandria – Quarry (St Cloud) 345 kV circuit 2
      - Monticello – Quarry (St. Cloud) 345 kV circuit 2
   c. Corridor Study facilities ($315 M)
      - Hazel Creek – Panther – McLeod – Blue Lake 345 kV double circuit
   d. RES Update Study facilities – Western ($843 M)
      - Maple River – Hankinson – Big Stone 345 kV double circuit
      - Big Stone – Brookings County – Split Rock 345 kV double circuit
   e. RES Update Study Facilities – Southwest ($692 M)
      - Lakefield Junction – Adams – La Crosse 345 kV double circuit
   f. Big Stone II Transmission ($173 M)
      - Big Stone – Canby – Hazel Creek 345 kV
      - Big Stone – Johnson – Morris 230 kV
      - Morris 230/115 kV Transformer Upgrade
   g. Eastern Interconnect facilities ($350 M)
      - La Crosse – West Middleton 345 kV project[22]

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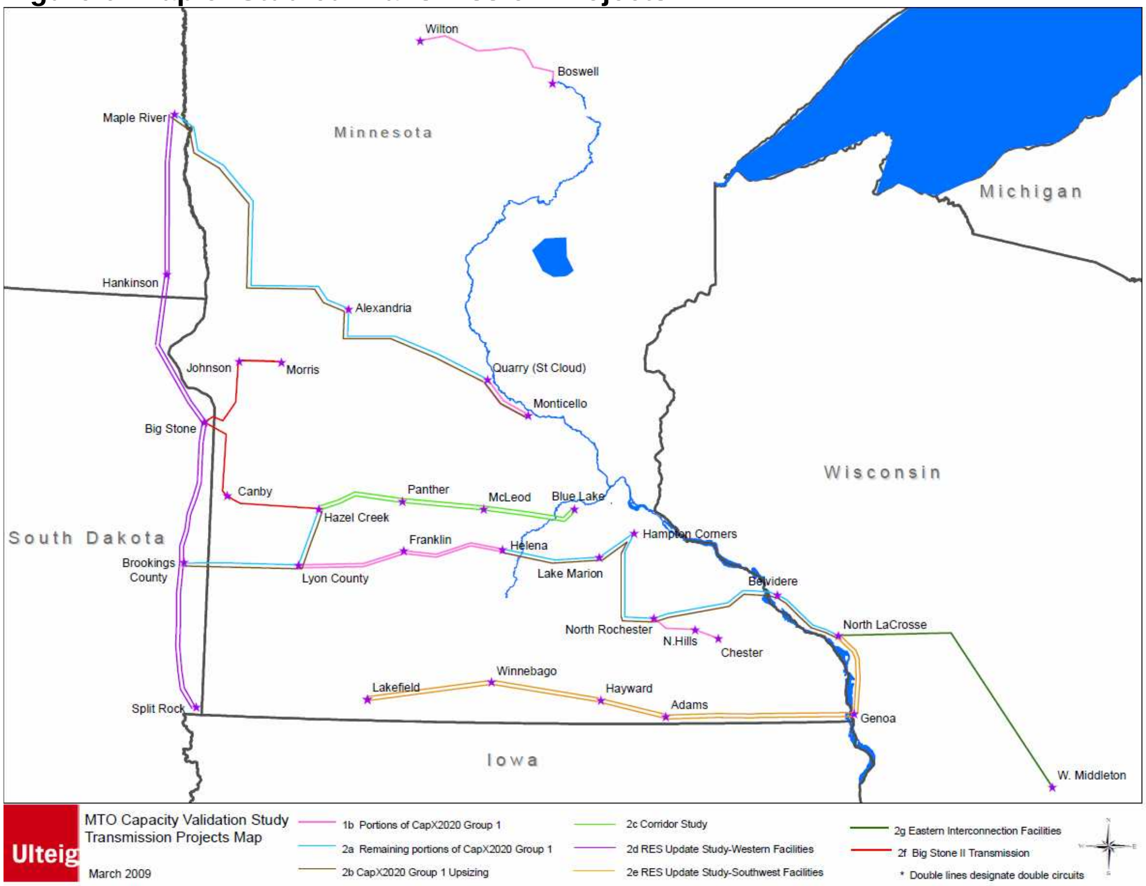
[21] The estimated project costs are approximate overnight costs in 2007 dollars and are based on project estimates created for each project by CapX2020, Xcel and Ulteig Engineers. These values were used in this study for determining the stopping point for the transfers.

[22] This study assumed West Middleton to be the end point of this line. Joint study work is underway with ATC (American Transmission Company), DPC (Dairyland Power Cooperative),

Figure 6: Map of Studied Transmission Projects



<u>Cost Data for Upgrades</u>

One of the most complex and time-intensive efforts of the study was to estimate the underlying system upgrade costs, which determines the stopping point for the addition of more transfer capability. After the power flow simulations were complete, the study compiled a list of all of the facilities that were identified as reaching their rating limit during the transfers. Each facility was evaluated at a high level to determine if the rating was the result of an equipment limitation or due to thermal rating of a conductor or some other reason. Then the fix was assigned a cost using a common unit cost table. The complete list of limiters and estimated upgrade costs can be found in Appendix C. Table 8 is a list of the unit cost data that was used in the study. The unit values come from the 2006 estimate for the CapX2020 Group 1 facilities which was estimated at the time to cost \$1.3 B. The current estimates for Group 1 is \$1.7B, thus the unit costs were increased by 30% to match the current estimates which are in 2007 dollars.

Xcel Energy, GRE, ITC, and SMMPA to identify the best actual endpoint for this project in the Madison Wisconsin Area.

Table 8: Unit Cost Upgrade Assumptions

Lines	$/mile ($1,000's)	
Reconductor 115-230	156	
Reconductor 345	234	
Rebuild 115	481	
Rebuild 161	585	
Rebuild 230	715	
Rebuild 345	1,900	
Equipment Replacement	130	
500 kV line increase	11,000	(physical cost only)
Transformers	($1,000's)	MVA size
500/230	26,000	1200
500/345	26,000	1200
345/115	6,032	448
345/161	4,940	400
345/230	4,680	336
230/115	4,160	336
230/69	3,380	
115/69	3,250	
161/115	2,700	

IV Study Details

A. Study Analysis

Steady state analysis was conducted to examine the transfer of power from the assumed source locations to the assumed sinks in order to test various combinations of planned transmission projects. The study used a combination of AC and DC solution methods to achieve the results due to the large number of scenarios examined and the relatively large footprint being studied. The study looked at power transfers of up to 6000 MW from source to sink in addition to the wind that was already in the base model. 6000 MW was used because it is at the upper end of the 4000-6000 MW range of renewable generation the utilities have estimated would be needed to meet the Minnesota RES.

Tools

The steady state analysis was conducted using the Siemens Power Technology Inc. Power System Simulator for Managing and Utilizing System Transmission (PSS™MUST) (Rev. 9.0) and Power System Simulator for Engineering (PSS™E) (Rev. 30.3) power flow program. Both are interactive digital computer programs for simulating, analyzing, and optimizing power system performance. PSSE was used for model building and error checking and MUST was used for the power transfer capability analysis. In MUST the AC-FCITC (AC First Contingency Incremental Transfer Capability) function was used. This function reports the MW level of system transfer that a particular transmission facility can accommodate either system intact or post contingent before becoming loaded above its specified rating.

Monitored Facilities and Contingencies

Facilities in the Northern MAPP region 115 kV and above were monitored under both system normal and during contingencies. Contingencies were applied to 161 kV and above facilities over the same region for both single element N-1 and specified multi-element NERC Category B and common tower outages. The study used a Midwest ISO multi-element contingency file developed for the RES Update and Corridor studies as well as a contingency file developed for the DRG study. These contingency files were updated to include the transmission projects being studied. Below is a list of the areas that were both monitored and over which contingencies were applied.

Table 9: Areas Monitored

Area Number	Organization
331	International Transmission Co – Midwest (ITCM) (formerly ALTW)
600	Xcel Energy (Xcel) (NSP Service Area)
608	Minnesota Power (MP)
613	Southern Minnesota Municipal Power Agency (SMMPA)
618	Great River Energy (GRE)
626	Otter Tail Power (OTP)
652	Western Area Power Administration (WAPA)
667	Manitoba Hydro (MH)
680	Dairyland Power Cooperative (DPC)

Screening Criteria

The study used the *Midwest ISO Guideline for Conducting Deliverability Study*[23] as a starting point for the screening criteria. A facility was considered overloaded at 100% of Rate A (normal rating) for system intact and 100% of Rate B (emergency rating) for contingencies. The emergency rating typically has a 30 minute timeframe associated with it during which the system needs to be adjusted to reduce the flow on that facility to less than its normal rating. Generation projects typically elect to reduce output during contingencies rather than make physical system upgrades due to the relatively small likelihood of prolonged outages. Therefore the study team concluded that it would be appropriate to screen using the emergency rating.

[23] http://www.midwestmarket.org/publish/Document/3e2d0_106c60936d4_-767f0a48324a?rev=4

The criteria for determining whether a facility was significantly affected were 3% for both OTDF (outage transfer distribution factor) [24]and PTDF[25] (power transfer distribution factor). Midwest ISO typically uses a 3% and 5% cutoff for OTDF and PTDF respectively. It was decided that since this study was a high level study that was more interested in identifying potential system problems rather than identifying the specific cause of a problem, then the slightly lower criteria would be appropriate.

The MUST FCITC function can be used in either a strictly DC manner or a combined AC and DC manner. This study used the combined AC and DC solution. MUST first runs a DC screen on all of the contingencies, then uses a specified number (this study used 150) of worst DC contingencies to run an AC solution. The advantage of the DC screen is that it can be performed much more quickly and is not susceptible to non-convergence[26] issues. The advantage to using the AC solution is that it is more accurate by taking into account voltage issues and reactive flows. However, the AC solution is susceptible to non-convergence issues and thus a solution may not be easily obtained. In this study the AC solution values were used except in situations where the AC solution failed to converge, in which case the DC solution value was used.

Scenarios Studied

During the initial study scoping, the study team decided to limit the project combinations to the more likely potential scenarios. Given that there are seven overall projects that were being studied, if every combination of projects were studied, 5040 (7!) combinations would have to be studied for each source-sink combination. Therefore the study team chose to focus on 24 of the more likely transmission scenarios which are listed in table10 below. Since the CapX2020 Group 1 transmission scenario is in the middle of the Certificate of Need process, it was assumed to be in all transmission scenarios except the base case and only portions of it were included in 1ab.

Table 10: Transmission Project Scenarios

Scenario	Description
1a	Base case, no new transmission
1ab	Portions of CapX2020 Group 1
2a	All of CapX2020 Group 1
2ab	CapX2020 Group 1 Upsized
2ac	CapX2020 Group 1 and the Corridor
2ad	CapX2020 Group 1 and Fargo to Sioux Falls

[24] OTDF is the percentage or proportion of a transfer that flows across a particular transmission facility associated with an outage (contingency) condition.
[25] PTDF is the percentage or proportion of a transfer that flows across a particular transmission facility associate with a system intact condition.
[26] Non-convergence is when the software fails to solve the mathematical model using its iterative algorithms for solving non-linear equations describing the system and is not able to return a valid mathematical answer.

2ae	CapX2020Group 1 and Lakefield to Adams to La Crosse
2af	CapX2020 Group 1 and Big Stone II Transmission
2ag	CapX2020 Group 1 and La Crosse to West Middleton
2abc	CapX2020 Group 1 Upsized and the Corridor
2abd	CapX2020 Group 1 Upsized and Fargo to Sioux Falls
2abe	CapX2020 Group 1 Upsized and Lakefield to Adams to La Crosse
2abf	CapX2020 Group 1 Upsized and Big Stone II Transmission
2abg	CapX2020 Group 1 Upsized and La Crosse to West Middleton
2acd	CapX2020 Group 1, Corridor and Fargo to Sioux Falls
2ace	CapX2020 Group 1, Corridor and Lakefield to Adams to La Crosse
2acf	CapX2020 Group 1, Corridor and Big Stone II Transmission
2acg	CapX2020 Group 1, Corridor and La Crosse to West Middleton
2abcf	CapX2020 Group 1 Upsized, Corridor and Big Stone II Transmission
2abcg	CapX2020 Group 1 Upsized, Corridor La Crosse to West Middleton
2abfg	CapX2020 Group 1 Upsized, Big Stone II Transmission and La Crosse to West Middleton
2abcfg	CapX2020 Group 1 Upsized, Corridor, Big Stone II Transmission and La Crosse to West Middleton
2acdefg	CapX2020 Group 1, Corridor, Fargo to Sioux Falls, Lakefield to Adams to La Crosse, Big Stone II Transmission and La Crosse to West Middleton
2abcdefg	CapX2020 Group 1 Upsized, Corridor, Fargo to Sioux Falls, Lakefield to Adams to La Crosse, Big Stone II Transmission and La Crosse to West Middleton

When evaluating the smaller pockets of sources, the list of combinations was reduced further to only nine scenarios (2ab, 2ac, 2ag, 2abd, 2abe, 2abg, 2acd, 2abcg, 2abcdefg). As cited earlier, the pockets were geographically defined as southeast Minnesota (SE), southwest Minnesota (SW) and a central-northwest Minnesota & eastern North Dakota (NW) set of sources. Since there were three sets of sources instead of only one set of sources, the study team needed to prioritize the combinations. Table 11 is a summary of the various combinations of sources, sinks, interface levels, and transmission scenarios which a total of 252 ACFCITC simulations being performed.

Table 11: Summary of the Scenarios Studied

Phase	Sinks	Sources	Interface levels (NDEX, MHEX, MWEX)	Number of Transmission Scenarios	Number of cases
Phase I Part 1	1, 2, 3	All combined	At Limit	24	72
Phase I Part 2	1, 2	NW, SW, SE (separately)	At Limit	9	54
Phase II Part 1	1, 2, 3	All combined	Historical level	24	72
Phase II Part 2	1, 2	NW, SW, SE (separately)	Historical level	9	54
				Total Simulations	252

<u>Stopping Criteria</u>

One of the biggest challenges of a study of this nature is to determine at what limit one would logically stop the transfer of power from the sources to the sinks. In other words, at what point do the underlying system upgrades become so great that something larger should be built rather than just fixing the system elements as they reach their limits. Typically in a study that is attempting to evaluate transmission options, one would plot the transfer capability versus the upgrade costs and attempt to find where the slope of the graph becomes too steep (where the costs rise faster than the capability created). These graphs are included in Appendix D. However, due to the sheer number of scenarios being studied, the study team came up with set of logic criteria to determine the stopping point of a particular scenario.

- For any case that does not include the La Crosse – West Middleton 345 kV transmission line (project 2g of the options studied), an overload of the King – Eau Claire or the Eau Claire – Arpin 345 kV line before any other criteria are met, is a stopping point. This line is so heavily utilized that it would not be possible to take it out of service to be able to upgrade the capability of the line. [27]
- For any case that does not include the Brookings County – Twin Cities project (this only applies to the base case), an overload of the Granite Falls – Blue Lake 230 kV line before any other criteria are met, is considered a stopping point. Again, this line is so heavily utilized that it

[27]As an example of the general difficulty in taking the King – Eau Claire – Arpin line out of service, recent structure upgrades along the line were performed during low-load hours while the line was energized.

would not be possible to take it out of service to be able to upgrade the capability of the line.

- Once underlying system upgrades reach 10% of the total base price for that transmission scenario, and a single underlying system upgrade costing more than $17.5 Million occurs, the stopping point would be considered the transfer achieved just prior to the $17.5 Million jump. The 10% value was chosen as this is about where the stopping point of other projects has occurred (825 MW upgrades and the Brookings to Twin Cities Project). The $17.5 Million dollar value was chosen as this was the breakpoint where most 115 kV and 161 kV facilities (which can be taken out of service more easily and upgraded more quickly) were under this value and most of the 230 kV and 345 kV facilities (which cannot be take out of serves as easily and take longer to upgrade) were above this level of cost.[28]

Loop flow through Manitoba and down the 500 kV line has been an issue in the past as well as in this study. Due to the complicated nature of the issues surrounding the 500 kV line, a sensitivity analysis was performed where it was assumed that the 500 kV line could not be fixed and would be considered a hard limit similar to the King – Eau Claire – Arpin 345 kV line or the Granite Falls – Blue Lake 230 kV line.

[28] As an example, if a project has a base cost of $1B, then there would have to be $100M in underlying system upgrades and then a single project of greater than $17.5M which would determine the stopping point of the transfer. It should also be noted that this isn't necessarily the limit for any given project, it is simply a means of automating the analysis and being able to compare projects on an equal set of criteria.

Results

The goal of this study was to estimate the range of wind outlet capabilities for various combinations of planned and proposed transmission projects. Below are several tables and graphs summarizing the potential outlet capabilities of the various transmission configurations, source, sink and interface level assumptions. In order to draw conclusions from these results, one needs to take into account the information from all of the tables and graphs in this section; therefore the discussion of the results and conclusions of this information will take place in the next section.

Table 12: Summary of transfer capabilities for each transmission scenario with the given sink set and interface level for all sources combined

		Max Interface Flow Scenario			Historical Interface Flow Scenario				
Transmission Scenario[29]	Scenario Base Cost ($ M)	Twin Cities Sink (MW)	Midwest ISO Sink (MW)	N. MAPP Sink (MW)	Twin Cities Sink (MW)	Midwest ISO Sink (MW)	N. MAPP Sink (MW)	Min (MW)	Max (MW)
1a	$ -	-421	-211	1342	1805	1801	2028	-421	2028
1ab	$ 593	1261	1248	2381	2180	1752	3898	1248	3898
2a	$ 1,732	3106	1791	5469	4631	2415	5709	1493	5709
2ab	$ 2,213	3423	1953	5723	4796	2627	5806	1953	5806
2ac	$ 2,047	3993	1725	6000	5730	2340	6000	1725	6000
2ad	$ 2,575	3821	1937	6000	5365	2531	6000	1937	6000
2ae	$ 2,424	3791	2101	6000	5075	2722	6000	2101	6000
2af	$ 1,905	3512	1740	6000	4679	2345	6000	1740	6000
2ag	$ 2,082	3689	3330	6000	4484	4034	6000	3678	6000
2abc	$ 2,528	5208	2031	5888	6000	2662	6000	2031	6000
2abd	$ 3,056	4448	2232	6000	5880	2842	5850	2232	6000
2abe	$ 2,905	3842	2198	6000	5529	2859	5827	2198	6000
2abf	$ 2,386	3977	2099	6000	5102	2710	6000	2099	6000
2abg	$ 2,563	3714	3667	5603	5086	4601	6000	3667	6000
2acd	$ 2,890	4873	1811	6000	6000	2490	6000	1811	6000
2ace	$ 2,739	4356	2060	6000	6000	2583	6000	2060	6000
2acf	$ 2,220	4529	1699	6000	6000	2327	6000	1699	6000
2acg	$ 2,397	3982	3398	6000	6000	3917	5897	3398	6000
2abcf	$ 2,701	5774	1979	5592	6000	2669	5776	1979	6000
2abcg	$ 2,878	5106	4248	6000	6000	4915	6000	4248	6000
2abfg	$ 2,736	3867	3617	6000	4899	4724	5859	3617	6000
2abcfg	$ 3,051	5953	4781	6000	6000	5319	6000	4781	6000
2acdefg	$ 4,105	5736	4933	6000	6000	5372	6000	4933	6000
2abcdefg	$ 4,586	6000	5458	6000	6000	5743	6000	5458	6000

[29] See the list onSection IV A for the detailed explanation of each scenario

Table 13: Summary of transfer capabilities for each transmission scenario with the given sink set and interface level for each group of sources (Pocket Analysis).

		Max Interface						Historical Interface							
		Twin Cities Sink			Midwest ISO Sink			Twin Cities Sink			Midwest ISO Sink				
Transmission Scenario	Scenario Base Cost	Northwest Sources (MW)	Southwest Sources (MW)	Southeast Sources (MW)	Northwest Sources (MW)	Southwest Sources (MW)	Southeast Sources (MW)	Northwest Sources (MW)	Southwest Sources (MW)	Southeast Sources (MW)	Northwest Sources (MW)	Southwest Sources (MW)	Southeast Sources (MW)	Min (MW)	Max (MW)
2ab	$ 2,213	1608	2689	2893	1437	2147	2518	2389	3000	3000	1824	2765	2703	1437	3000
2ac	$ 2,047	2088	3000	3000	1264	1702	2391	2212	3000	3000	1771	2289	2763	1264	3000
2ag	$ 2,082	1964	2499	3000	1245	2295	2898	2247	3000	3000	1889	2848	3000	1245	3000
2abd	$ 3,056	2731	3000	3000	1811	2213	2509	3000	3000	2685	2198	3000	2985	1811	3000
2abe	$ 2,905	2038	3000	3000	1440	2380	2591	2370	3000	2848	1850	3000	3000	1440	3000
2abg	$ 2,563	2263	2786	3000	1567	3000	3000	2461	3000	3000	2029	3000	3000	1567	3000
2acd	$ 2,890	2706	3000	3000	1598	1791	3000	3000	3000	3000	2125	2402	2772	1598	3000
2abcg	$ 2,878	2362	3000	3000	1534	3000	3000	2287	3000	3000	2041	3000	3000	1534	3000
2abcdefg	$ 4,586	2894	2986	2984	2535	3000	3000	3000	3000	3000	3000	3000	3000	2535	3000

Figure 7: Graph of Power Transfer Max Interface – All Sources – All Sinks
Summary of transfer capability for each transmission scenario given the sink for all sources combined under the Max Interface scenario. Each bar represents the estimated transfer capability for each transmission option for the given assumptions. The maximum transfer that was simulated was 6000 MW, thus none of the lines are above 6000 MW.

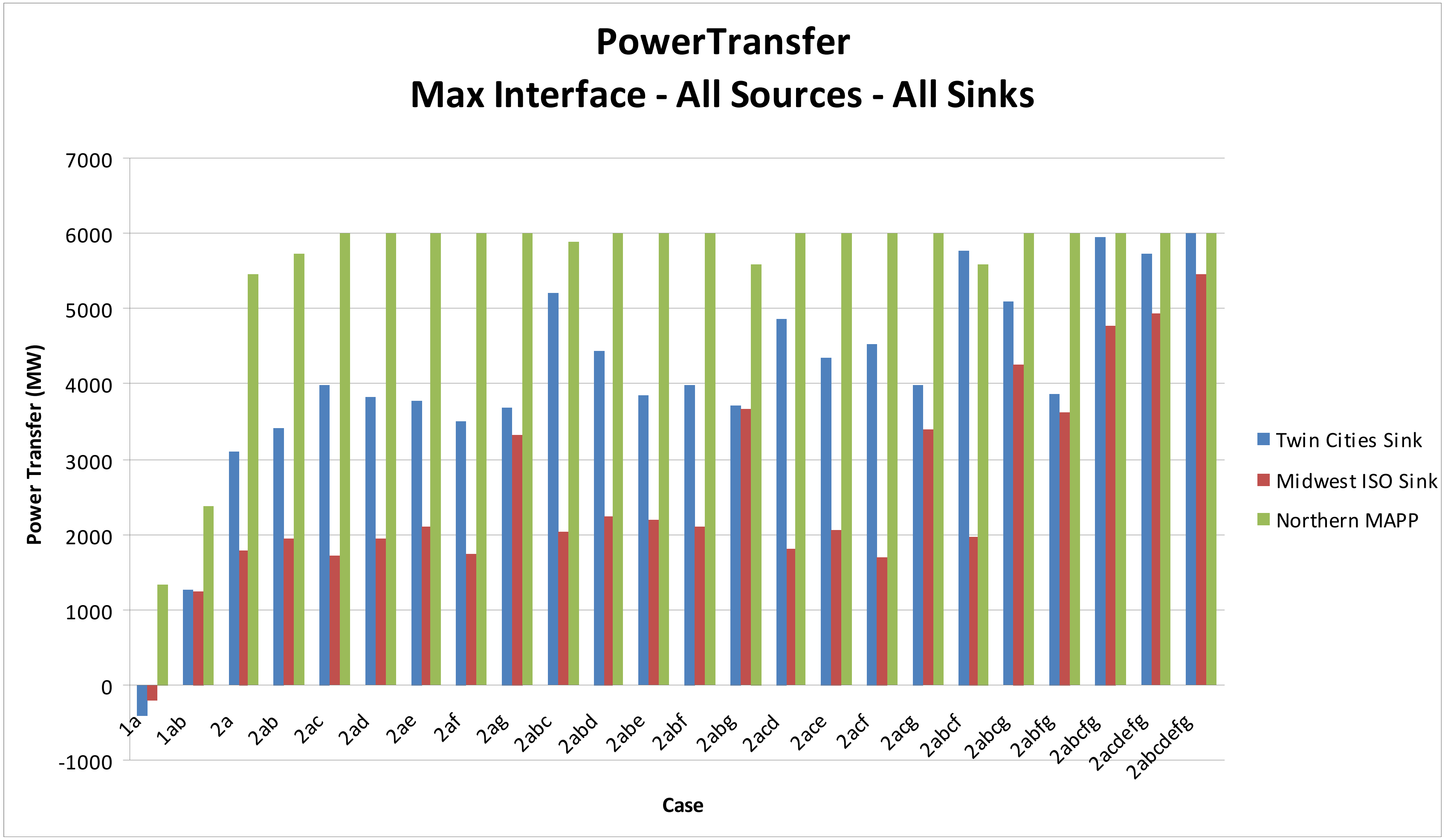


Figure 8: Graph of Power Transfers Historical Interface – All Sources – All Sinks

– Summary of transfer capability for each transmission scenario given the sink for all sources combined under the Historical Interface scenario. Each bar represents the estimated transfer capability for each transmission option for the given assumptions. The maximum transfer that was simulated was 6000 MW, thus none of the lines are above 6000 MW.

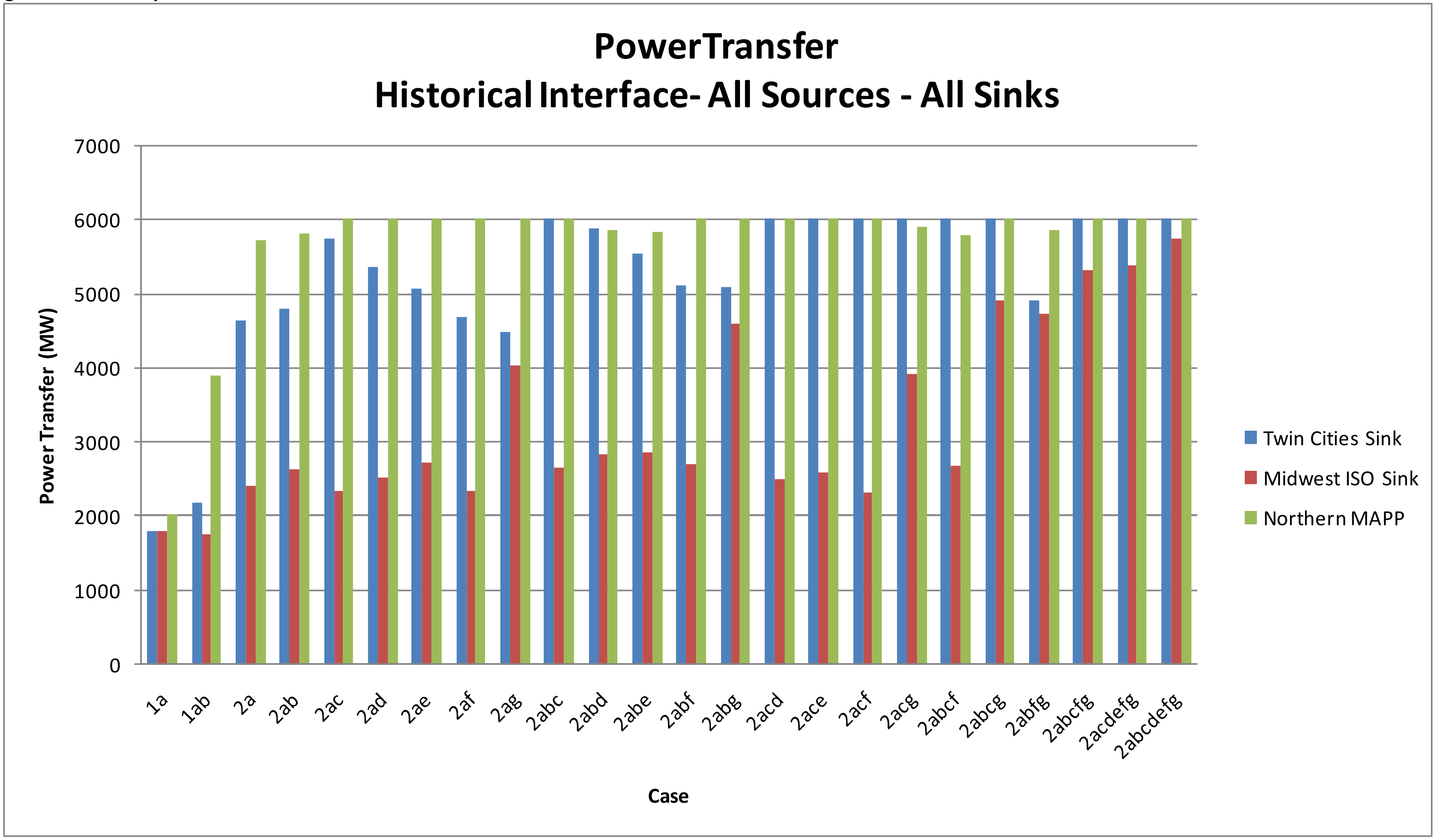
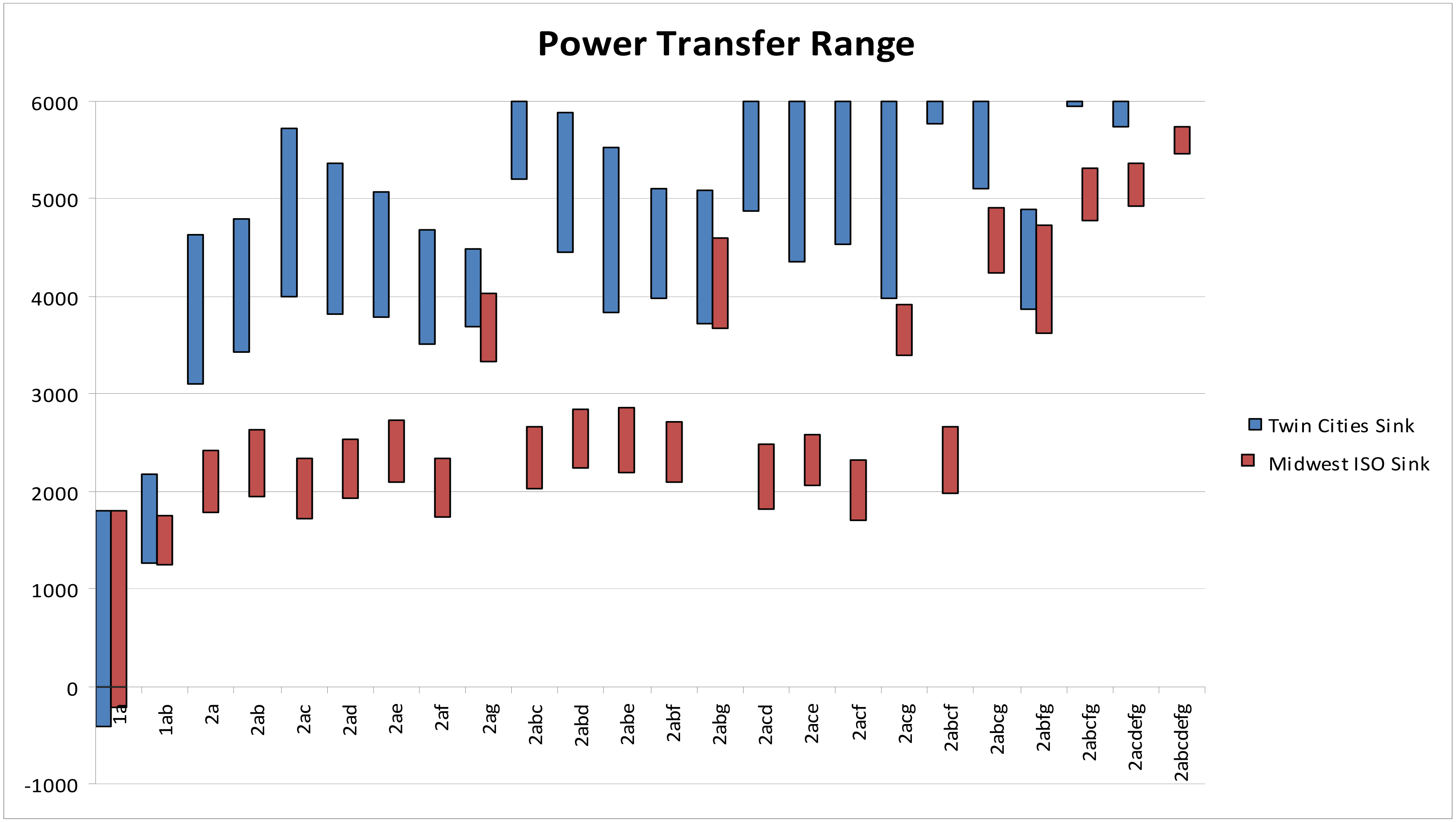


Figure 9: Graph of Power Transfer Range

– Summary of the range of transfer capabilities for each transmission option for the Twin Cities and Midwest ISO Sinks. On this graph the lower bookend is the result from the Max Interface, the higher bookend is the result from the Historical Interface scenario. The maximum transfer that was simulated was 6000 MW, thus none of the lines are above 6000 MW.



Observations

The results presented in the Capacity Verification Study are all based on a specific set of assumptions, which are the main driver of the results observed. Should any of the assumptions change such as source location, sink location, exact transmission configuration, etc., the results of the study will change. The CVS was meant to be a high level visionary study to help the utilities decide where to focus their effort in the near term and to validate the findings of previously completed studies. While care was taken to develop reasonable assumptions, they are still assumptions that are subject to change.

Since the CVS was a vision-type study, only steady state thermal analysis was completed. This was done because of the large number of scenarios simulated. For more detailed and precise results, stability analysis, loss analysis, operational analysis, in depth voltage and var analysis, optimization of project configurations, and possibly other analysis would need to be conducted.

The CVS has simulated a very large number of possible scenarios resulting in the production of a very large amount of data. The CVS report does not attempt to point out all of the possible conclusions that could be made from this study, but will discuss some of the more significant findings from the analysis of the results. As one reviews the results of the study and attempts to look at the details of the results, care needs to be taken to not forget the base set of assumptions and the original goal of the study.

The total cost of adding generation to the system is made up of three separate costs: transmission cost, production cost, and system operation cost. The CVS only dealt with the issues surrounding a portion of the transmission aspect of the electrical energy grid. The actual costs of developing and integrating the large amount of wind included in the study have not been conducted. All three elements of the electrical energy grid would need to be studied in detail to evaluate the total cost paid by the utility customers.

The CVS was not an interconnection study. Even though the study team attempted to perform the study using similar techniques and criteria used in an interconnection study, the CVS does not replace the need and requirement for an interconnection study for any of the source locations. Nor does the CVS guarantee similar results for any source location for an interconnection study of a specific project.

B. Key Findings

Sink Observations

One of the most apparent findings is vastly different amounts of power transfer capability are observed depending on which sink is being used. The results show that in general, sinking to the Midwest ISO footprint provides the least amount of transfer, sinking to the Northern MAPP sink provides the most transfer capability, and the Twin Cities sink's transfer capability is somewhere in between. The following sections will be on the pros and cons to each of the sink scenarios and their applicability to generation and transmission development.

Northern MAPP Sink

The Northern MAPP sink is comprised of base load generating units located in central North Dakota, northern Minnesota and around the Twin Cities. These units represent the locations from which a majority of the energy used in Minnesota originates. Although it is impossible to track the exact path of an electron from generation to consumption, from a contractual and ownership basis the previous statement is true. The purpose of the Northern MAPP sink was to simulate the Minnesota utilities taking physical delivery of the wind energy and replacing where they have typically generated a majority of their energy with wind energy.

It is not surprising that this scenario provides for the most transfer capability. The general transfer direction of the Northern MAPP sink is in the opposite direction of typical system flows. Flows are typically from North Dakota and northern Minnesota to the south and east. These flows are the opposite of going from the wind locations to sinks in the north and west. The opposing flows from the wind energy actually reduce flow on many of the lines in the region. The reduction allows for large amount system transfer with only a few newly constructed facilities being necessary. As seen from the results, only one or two of the transmission projects are needed to achieve the maximum energy transfer level of 6000MW.

However, the Northern MAPP sink may not represent a realistic scenario. The Northern MAPP sink may work for a small amount of generation, but not in the quantity being studied. Base load generation is intended to generate at a set (base) level as this level is where it is the most efficient and economic. It is widely accepted that wind generation levels can rapidly fluctuate in response to sudden meteorological changes. As larger generation units are turned off and the extent to which the system depends on wind generation increases, these changes in weather patterns can very quickly cause a shortfall in the amount of available generation to serve instantaneous demand. With significant base load generation offline and startup times ranging from several hours to several days, it would not be possible for these units to respond to a sudden drop in available wind generation. The reverse is also a potential issue. If wind generation levels are relatively low, base load generation units are producing at full capacity to meet the system's real-time demand. However, if wind generation suddenly increases, the larger generators would have to be taken offline in rapid fashion. These sudden tripping operations tend to have a detrimental impact on larger generators and should be avoided. These are some of the steady-state challenges that come with integrating significant levels of wind generation within a transmission-constrained footprint.

In addition to these challenges, there is also a very realistic concern with reducing the system's inertia and causing system instability should large scale shutdown of base load generation be pursued. The presence of base load generators helps the system absorb faults and significant power disruptions. Smaller, more variable generation sources are more susceptible to these fluctuations and to the extent the system relies upon these generation sources at the cost of shutting down existing generation, the system's general stability may suffer. As mentioned above, the CVS did not investigate stability analysis due to the sheer volume of scenarios being studied. However, some stability analysis was pursued in conjunction with the RES Update Study. For a review of the stability implications of increasing wind penetration, readers can refer to that study.

The Northern MAPP sink reached the maximum transfer level (6000 MW) in nearly every transmission scenario. Therefore it is not possible to compare or draw any conclusions about specific transmission projects or combinations of transmission projects using the Northern MAPP sink. This result was recognized early in the analysis and thus the choice was made to remove the Northern MAPP sink from the pocket analysis section of the CVS. The remainder of the discussion will focus only on the other two sink options analyzed.

<u>Twin Cities Sink</u>

The Twin Cities sink is comprised of baseload generating units located in and around the Twin Cities. These sinks represent where a majority of the load in Minnesota is located. Previous studies have examined sinking wind to the Twin Cities as this is where Xcel Energy, who has been the purchaser of a majority of the wind in the past, has a majority of its generation and load. The Twin Cities sink has historically been considered a worst-case scenario as it is generally adding flows in the same direction of typical system flows. The Twin Cities sink simulates Xcel Energy taking physical delivery of the wind generation by replacing typical Xcel Energy generation with wind generation. The specific units in the Twin Cities sink were used because these were the only units left on in the Twin Cities Area.

However, the Twin Cities sink may not be a realistic scenario. For the same reasons as stated for the Northern MAPP sink, it is not realistic to assume that Xcel Energy would shut down base load generating units in the Twin Cities and rely solely on wind generation. The Twin Cities sink would be valid up to a certain level of wind penetration, but not at the higher levels simulated in the CVS.

One potential issue not specifically analyzed in this study (due to the way the MUST FCITC function works), is voltage and var support issues in the Twin Cities area using assumptions under this sink scenario. If Xcel Energy were to actually shut down as much generation in the Twin Cities as was simulated in the CVS, it is expected that large amounts of reactive capacity would need to be installed in the Twin Cities area. As generation moves further away from the load, more reactive support is needed at the load and on the transmission in between to support the system voltages. By using the MUST FCITC function, it is not possible to analyze voltage issues because MUST never fully takes a generating unit offline. This misrepresents the var support provided by the sink generators. In MUST the unit is still capable of producing or consuming vars based on its predefined capability as long as the unit is online in the simulation.

Midwest ISO Sink

The Midwest ISO sink was comprised of units in the eastern portion of the Midwest ISO footprint. The Midwest ISO sink represents the delivery of wind energy to the greater Midwest ISO market. The Midwest ISO sink does not represent physical delivery to any specific entity or location. It is more representative of a merit order dispatch in which the low cost baseload units in the region are online along with the wind generation.

The Midwest ISO sink is the most limiting sink due to the low number of high voltage connections between the western and eastern portions of Midwest ISO. Currently, there exists only two 345 kV lines between Minnesota and Wisconsin and only two 345 kV lines between Iowa and Illinois. One of the 345 kV lines, between King (Minnesota) and Eau Claire (Wisconsin), is the limiting element in most of the Midwest ISO sink transmission scenarios. The only scenarios in which the King – Eau Claire line is not a limiting element is when a line from La Crosse, Wisconsin to the Madison, Wisconsin (project 2g of the projects studied) area is included. All transmission using the Midwest ISO sink and transmission scenarios with the La Crosse – Madison line have a significantly larger amount of transfer capability than transmission scenarios without this line.

Of the scenarios studied, the Midwest ISO sink is the most realistic. The Midwest ISO sink scenario most closely matches how Midwest ISO would perform a deliverability test. The deliverability test would be performed by sending the output of a new generator across the entire Midwest ISO footprint. The Midwest ISO sink analysis also reflects the unlikelihood that wind generation will realistically be able to interconnect to the system with existing baseload generation turned off. In the interconnection studies, the generation owner would have to demonstrate that both the new generation and the existing generation can both generate simultaneously, without impacting the firm rights of the existing generation[30]. Also, by ensuring the system is capable of sinking to the

[30] It may be possible for wind projects to enter into contracts with nearby peaking units such that the output of both units is capped to the firm rights of the existing units, similar to what was done

Midwest ISO market, one can be assured the overall system will be dispatched in the most economical manner and will not be limited by congestion on the transmission system.

Pocket Analysis

The pocket analysis[31] was undertaken to ensure that there were not any significant issues that would potentially be missed do to the large number and geographically dispersed set of sources used in the initial analysis. The analysis did show lower transfer levels were achieved by each individual pocket of sources; however each pocket still achieved a significant level of transfer capability.

Overall, the pocket analysis did not reveal anything unexpected. The lower transfer levels achieved by each pocket compared to all of the sources together was expected as the impact on individual transmission facilities was more concentrated and thus facilities that ended up being the stopping point reached their limits sooner. Also not surprisingly, the NW source set achieved the least transfer while the SE source set achieved the most. This was due to the NW sources being furthest from the sink locations and the SE was closest to the sink locations. The NW sources also had the most impact on the 500 kV line as they are closest to the north end of the 500 kV line.

Priority Transmission Projects

Based on the CVS results of the various sinks and transmission scenarios, it appears that the CapX2020 Group I, the Corridor, the La Crosse – Madison line and possibly the Upsizing of CapX2020 Group I should be the focus of the Utilities' transmission expansion efforts in the near term. Both individually and in combination, these transmission projects appear to provide the most transfer capability across the variety of underlying assumptions.

The CapX2020 Group I projects appear to provide more outlet capability than had previously been thought. The increase is likely due to the projects being studied on combined basis and not just individually. The combination of transmission provides more transfer capability. The effort to move these projects through the regulatory and construction processes should continue as scheduled. The CapX2020 group I projects should also be built with the capability to be double circuited (Upsized); the upsizing will be discussed further in the conclusion.

The results of the CVS indicate a line to the east is needed. In nearly every transmission scenario sinking to the Midwest ISO footprint the King – Eau Claire

between the Trimont Wind Farm and the Lakefield Generating Station, but this arrangement is highly unlikely with a Baseload unit.

[31] Results of the pocket analysis are included in Appendix D.

line is the limiting element, except when there is a line parallel to it between La Crosse, Wisconsin and the Madison, Wisconsin area (project g). As discussed previously, the Midwest ISO sink is the most appropriate sink for simulating how the transmission system is currently planned and operated. From the graphs and tables, one can see each scenario containing the La Crosse – Madison line provides more transfer capability when sinking to Midwest ISO than any of the scenarios without the line. The CVS only examined the line as a single circuit, but it is possible a double circuit line would be justified[32].

The Corridor project should be the next project pursued in Minnesota for wind transfer. The CVS results indicate he Corridor project provides the most transfer capability to the Twin Cities sink at a low cost. The Corridor also provides the most benefit to transfers off the Buffalo Ridge where there is the greatest interest in interconnecting new projects. The 230 kV line between Granite Falls and Blue Lake has been shown to be the next major limiter for large amounts of energy transfers from western and southwestern Minnesota. However, due to the high utilization of the line, it is not possible to remove the line from service for an amount of time sufficiently long enough to upgrade the capacity of this line. After the Brookings County – Twin Cities line is completed, it would be possible to take the Corridor line out of service for construction, but the construction window is limited before the Corridor line is loaded back up again with more wind generation. If the Granite Falls – Blue Lake 230 kV line were taken out of service to be upgraded without a parallel line in place before the outage, existing generation in western Minnesota, North Dakota and South Dakota would be severely limited throughout the duration of the outage.

The Upsizing of the CapX2020 Group I facilities should be the next project after the Corridor Project for Minnesota. The CVS results indicate the Upsizing provides the most transfer to the Midwest ISO sink at the lowest cost. This is true with or without the La Crosse – Madison line. The upsizing allows for wind to be developed over a large geographic area. The double circuiting of the Fargo to the Twin Cities line allows for generation development in the northwest as well as redirects existing system flows down the Fargo to Twin Cities line rather than through the Buffalo Ridge Area. This redirection unloads the lines on the Buffalo Ridge and thus allows for more generation development in the Buffalo Ridge area. The double circuiting of the La Crosse – Twin Cities line would, in conjunction with the La Crosse – Madison Area line, direct more flow down that path to the Midwest ISO market.

The timing of the need for the Upsizing would determine if the CapX2020 Group 1 projects should be constructed as simply double circuit capable or built and operated as double circuit lines. Study work performed for the CapX2020 Group 1 Certificate of Need showed the outage of a double circuit Fargo – Twin Cities line to be one of the worse case scenarios that would overload other system

[32] More studies would be needed to see if a single or double circuit line is more appropriate, as well as what the ultimate end point should be – Columbia or West Middleton.

facilities when the double circuited line is heavily loaded. That study work concluded that the double circuit would therefore not provide a significant incremental transfer capability. Once the Corridor is in place however, it would be possible to utilize the increased capacity of a double circuited line. Although the CVS results did not demonstrate this same observation, it should be recognized that the CVS is just one study and the utilities need to look at several studies with varying assumptions in order to determine which facilities are needed and when.

If it is determined that the capability created by the upsizing is needed soon after the Corridor is completed, it may make sense to construct and operate CapX2020 Group 1 lines as double circuit facilities from the beginning. This would save from having to mobilize and perform construction on these facilities a second time and would prevent the need to take the lines out of service during the upgrades. Although it is expected that adding a second circuit to the CapX2020 Group 1 facilities will not require significantly long outages, the upgrades would need to occur before the initially constructed single circuits become so utilized that the system cannot handle the construction outages relating to the second circuit.

<u>500 kV Line</u>

Issues surrounding the 500 kV system need to be explored further. Portions of the 500 kV system were shown throughout the CVS as reaching their existing limits. The 500 kV system has the potential to be upgraded to a higher capacity by upgrading the series capacitors on the line as well as adding more transformation capacity and with some other minor equipment upgrades. These upgrades have relatively small dollar costs, however there are several other issues surrounding the line that would need to be dealt with.

One issue is that a loss of the 500 kV line is currently the largest single contingency in the region, which determines the amount of regional spinning reserve that is necessary to be online throughout the system. If the capability of the line is increased, the spinning reserve[33] requirement would need to be increased which, in turn, would increase the overall operational costs of the system.

Another issue with the 500 kV system would be related to the operational issues and runback[34] guides surrounding the line. There is currently a well defined operational guide for the 500 and 230 kV facilities that connect the United States to Manitoba which would need to be redefined. Currently, Manitoba generation

[33] Spinning reserve is generation that is online and capable of replacing power instantly if another unit on the system trips offline.
[34] A runback scheme is when a generator reduces output either instantly or over a very short time as a result of a system disturbance to prevent further overloads on the system.

and DC transmission power flow is decreased during contingencies based on the flows between the United States and Manitoba.

The complications of federal law would also be an issue for upgrading the 500 kV line. When the line was originally constructed, a Presidential Permit had to be issued due to this being an international facility. Similarly, during the Manitoba Minnesota Transmission Upgrade (MMTU) upgrade of the cross-United States-Canada-border capability, a Presidential Permit had to again be obtained. The terms of the Presidential Permit would need to be updated to reflect any new capabilities of the line. A Presidential Permit is required if cross-border facilities are upgraded or if new transactions are planned between the United States and Canada. A primary reason for the Presidential Permit is to show no degradation of the United States electric transmission system.

If the issues surrounding the 500 kV line cannot be resolved and it is not possible to upgrade the capability of the line, the transfer capabilities for wind will be greatly reduced, especially for wind projects located to the north and west of the Twin Cities. This is demonstrated by the sensitivity analysis which was performed where any element of the 500 kV line was considered to be a hard limiter and a stopping point for the wind transfer.[35]

<u>RES 2016 Goals Realized</u>

According to the results of the CVS, the RES 2016 goals should be met assuming the planned transmission projects can be permitted and constructed. The planned transmission projects necessary to achieve the 2016 RES goal are a combination of the CapX2020 Group I and Group I Upsized or the Corridor projects or all three. Each of these transmission projects have an in service date or potential in service date before 2016 according to the most recent schedules. The La Crosse – Madison area line may also be needed, but an operational study would be necessary in order to fully evaluate if Minnesota could handle the 2016 RES level of wind penetration with or without the project.

Other considerations may cause the transfer capability results of the CVS to be understated. There exists the possibility a wind project could be developed near existing peaking generation in an effort to utilize the firm capacity rights of the peaking unit. Under this scenario the wind generation could operate when the peaking unit was not running. The CVS evaluated the system based on firm transmission capability, but as is demonstrated by the Historical Interface analysis, there is the potential that wind generation could be built and operated for a majority of the time and then be curtailed during certain periods of extreme system conditions. Newly installed wind generation curtailment has already occurred, to some extent, on wind projects which have ER (non-firm) transmission service.

[35] Results of the 500 kV sensitivity can be found in Appendix D

Conclusions

This study validates the previous and concurrent study work completed by the MTO utilities. The results show that the transmission projects currently being pursued by the utilities are the correct projects and are being prioritized in the correct order. Although it is difficult to compare the various studies' estimated range of outlet capabilities created by a specific project, this study shows that generally the same amount of transfer should be able to be achieved as other studies have estimated. Overall, this study has not uncovered any issues or produced any finding that are contradictory to any of the other projects or study efforts.