Figure 4 - Corridor Study Generation Siting Region

Impact of Corridor Study Generation Sink Scenarios

The Corridor Study team studied two separate generation sink scenarios to determine the impact each alternative might have on the transmission system solution. The first method was to sink the generation to the full Midwest ISO market. This method is a realistic approach to model how the Midwest ISO actually dispatches its generation fleet, as it models the system most closely to real-world dispatch and provides the greatest chances of encountering the system limitations that limit generation dispatch on a real-time basis. Using this dispatch methodology also yields a strong, reliable system in times of high and low wind. In addition, this is the dispatch method the Midwest ISO utilizes in many of their regional studies and thus offers a fair representation of generator delivery capability.

The other method by which the system was analyzed assumed sinking the generation within Minnesota, mainly in the greater Twin Cities metro area. This approach allowed the study team to determine the effects of the significant addition of new energy sources to the energy grid within Minnesota. This tested how the Twin Cities metro area transmission system would react to large amounts of external generation serving the area load. This scenario would logically involve turning down (or off) large amounts of generation within the greater Twin Cities area. Examining this scenario provides valuable information to inform future generation dispatch and planning decisions, as it will help determine just how much distant generation can be dispatched to the greater Twin Cities area without risking the ability of the system to adapt in real-time to fluctuations in remote generation levels. Where the Corridor Study analyzed this impact in the steady-state and thermal realm, the stability analysis discussed within the RES Update Study addressed the real-time operational issues (i.e. system stability) associated with this dispatch scenario.

The Twin Cities generation sink scenario, along with constructing the necessary underlying system upgrades, facilitates approximately 2000 MW of delivery capacity to load centers in Minnesota. However, without the facility from La Crosse to the Madison area, system capacity is limited to the capacity levels resulting from the addition of the Corridor Upgrade and underlying projects. Further upgrades in Minnesota would not provide significant benefit prior to installation of a high-capacity path from La Crosse to the Madison area. As shown in the RES Update Study analysis, all of the next system upgrades necessary to meet future RES milestones require a line to the Madison area. In other words, without a line to the east the system will reach a "tipping point" where no more major capacity additions can be accommodated.

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.[21]

[21] On February 26, 2008, a sudden decrease in wind generation levels in Texas led to the interruption of 1100 MW of load to customers in the state.

Big Stone II Status

The study team dealt with the ambiguity of whether the Big Stone II project will be built by studying the situation with and without the Big Stone II generation and transmission facilities in place. The key outcome of this analysis showed that it is not necessary to have the Corridor Upgrade project extend west to Big Stone II to meet the 2016 RES milestone. Rebuilding the 230 kV line from Hazel Creek to Blue Lake to a 345 kV double circuit line is the best alternative from a transmission system performance perspective regardless of the final status of Big Stone II. However, there are benefits provided to additional generation by the Big Stone II transmission facilities. Significant levels of renewable generation projects, aside from Big Stone II, are seeking to interconnect in the vicinity of Big Stone II and the Corridor Study did not seek to make any judgments regarding the feasibility of interconnecting that generation.

Supporting Facilities for Corridor Upgrade

One outcome of studying the Midwest ISO Market sink scenario proved the system requires facilities connecting to the radial 345 kV Twin Cities – La Crosse line to deliver power east from La Crosse, Wisconsin to the rest of the Midwest ISO footprint during low load periods in Minnesota and the Dakotas. Consistent with the findings of the Minnesota Wind Integration Study,[22] this facility is necessary to enable the Minnesota transmission system to accommodate the levels of wind generation envisioned in the RES legislation. This new facility would also allow the Corridor Upgrade to achieve its full potential in the Midwest ISO market dispatch.

The Twin Cities metro sink scenario analysis showed that in order to sink upwards of 2000 MW of renewable generation to the Twin Cities, many of the metro area electric generation units must be shut down to allow the new generation to remain online. To enable the wind generation to be sunk in the Twin Cities metro and maintain reliable operations requires a significant list of metro area transmission system upgrades.

E. Cost Estimates for Corridor Upgrade Project

Based on the Twin Cities metro sink study results:

1. The core portion of the 345 kV double circuit upgrade project is estimated to cost approximately $350 million[23] with an additional $110 million in associated projects required.
2. Of this $110 million in underlying system projects, approximately 60% of them have been otherwise identified in unrelated system analyses, leaving slightly less than half of these underlying projects as totally tied

[22] The Minnesota Wind Integration Study can be found at: http://www.uwig.org/windrpt_vol%201.pdf.
[23] Note that these estimates are preliminary budgetary estimates and are subject to change.

to the Corridor Upgrade. The total cost of this scenario is therefore approximately $400 to $460 million and will result in a transmission system able to deliver roughly 2000 MW of additional generation. The study results are presented in ranges since there are many unknowns that could affect the generation capacity output and the associated costs, as well as the unknowns with the underlying system projects. A full list of the underlying system projects can be found in the technical report.

The Midwest ISO footprint sink scenario cost estimates begin with the same core project price tag of approximately $350 million. Since a 345 kV line needs to be built from La Crosse to Madison, Wisconsin to enable full reliable operation and delivery to the eastern portion of the Midwest ISO footprint, the additional costs are about $325 million[24]. This adds to a total cost estimate of approximately $675 million and, based on the findings of the RES Update Study, will result in a transmission system able to deliver as much as 3600 MW of new generation.

Based on the above results, it can be determined that the Midwest ISO market sink scenario, while having a higher price tag, will achieve a higher outlet capability (MW) per dollar spent than the Twin Cities sink scenario. In addition it will avoid the system stability difficulties prevalent with the Twin Cities dispatch. These stability results are outlined in more detail in Chapter VI, Section A of this report.

As discussed above, PROMOD simulations were conducted to test the behavior of the Corridor facilities within the Midwest ISO market dispatch. Table 4 provides information regarding the results of these analyses.

Table 4 - Cost for Corridor Upgrade

Description	Cost
Project Cost	$350,000,000
Underlying System Cost	$110,000,000
70% Production Cost Savings Offset	($35,000,000)
30% Load Cost Savings Offset	($180,000,000)
Loss Savings Offset	($152,000,000)
Net Project Cost	$93,000,000

The cost of the proposed project has been estimated at $350 million. With a Twin Cities dispatch, approximately $110 million in underlying system upgrades is necessary to achieve the full generation delivery capability of the project (2000 MW).

[24] This is an MTO estimate for an project which will be constructed by a non-MTO member, and therefore the estimate is subject to change as the project develops, as well as endpoints are determined.

As demonstrated in the table above, installation of the Corridor Upgrade results in sizeable production cost savings and significant load cost savings over an assumed 40-year project life. The values reflected in the table above represent 70% of the total production cost savings and 30% of the total load cost savings. A combination of the two is used to represent the hybrid regulated/deregulated nature of the Midwest ISO market. These proportions are consistent with the Midwest ISO's methods for economic analysis of projects.

In addition to the production cost and load cost savings, the Corridor Upgrade results in approximately 49 MW of loss savings. This equates to a present value of approximately $152 million.

Considering all the costs, the net project cost of the Corridor Upgrade is roughly $93 million. This demonstrates that, while steady state results demonstrate a significant generation delivery increase associated with the Corridor Upgrade, the project also brings about significant cost savings and has a highly beneficial impact on the transmission system in general – in particular with respect to the market dispatch employed by the Midwest ISO. Similar analysis was performed with respect to the facilities studied in the RES Update.

V. RES Update Study Details

A. RES Update Study Purpose

The RES Update Study examines the facilities needed after the Corridor Upgrade to provide a robust and reliable transmission system and to allow load serving entitles to satisfy the next RES goals (2020). It builds upon the results of the Corridor Study by investigating the best way to integrate the significant interest in generation development in and around Minnesota into the regional transmission system. The RES Update Study was designed to support the Corridor study work and included sensitivities to the development explored in the Corridor Study. These sensitivities helped to finalize the endpoints of the Corridor Upgrade and draw conclusions about generation delivery capability unlocked by combining the Corridor Upgrade with other regional transmission improvements. In addition, the final recommendations of the Corridor Study were considered when developing the RES Update Study's recommended facilities.

As mentioned earlier in this report, several factors have contributed to the evolution in information needed from the RES Update Study. The first factor is the greater than expected deliverability from the Corridor Upgrade. When the original Corridor Study project scoping took place, preliminary estimates assumed about 1000 MW of new generation delivery as a result of the Corridor Upgrade. Early estimates also projected an additional need of approximately 1000 MW beyond the Corridor Upgrade to meet the 2016 RES milestone.

Therefore, the original scope for the RES Update Study was to identify optimal additional facilities to ensure 2016 RES compliance.

Since the RES Update and Corridor Study teams worked closely together, the RES Update Study team could react to results as they surfaced during the Corridor Study analysis. The analysis from the Corridor Study showed that the generation delivery result from the upgrade could be around 2000 MW of additional generation output capability.

The second factor impacting the RES Update Study scope is the decrease in the rate at which load growth is occurring among regional utilities as a result of conservation efforts and present economic conditions. This fact is viewed cautiously given that history has typically shown that recessionary load levels quickly recover to pre-recessionary levels.

The third factor in the evolution of the RES Update scope is better-than-expected capacity factor from installed wind generation. In the original Gap Analysis[25], a lack of definitive wind generation capacity factor information led transmission planning engineers to conservatively estimate the average capacity factor at 30%. Several years of actual information have now placed the average wind turbine capacity factor at a level closer to 40%. The capacity factor is one way to measure the productivity of a wind turbine or any other power production facility. It compares the plant's actual production over a given period of time with the amount of power the plant would have produced if it had run at full capacity for the same amount of time. In other words, an increase in capacity factor from 30% to almost 40% means more energy is being generated per turbine and it will take fewer turbines to generate the amount of energy needed to satisfy the RES milestones.

Taking into account these three factors, the results of the Corridor Study suggest that its installation will provide sufficient generation delivery capability to meet the 2016 RES milestone.

As a result, the RES Update study evolved to focus on identifying transmission projects that could increase generation outlet capability from several popular generation development zones. These zones are located in North Dakota, southwest Minnesota and eastern South Dakota, and southeastern Minnesota. In addition, an analysis was conducted that attempted to meet the Minnesota 2016 RES milestone using only DRG projects. Table 5 shows the buses that

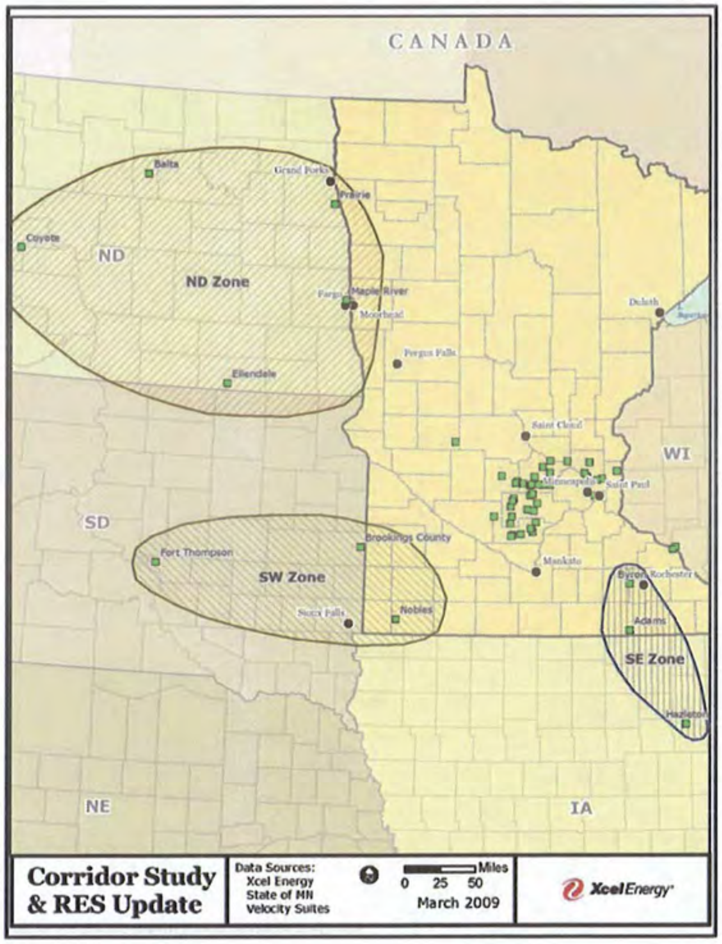
[25] The original Gap Analysis was conducted by the MTO for inclusion in the 2007 RES Report and calculated the amount of wind energy (in MW) that would be necessary to meet each RES milestone statewide and for each company. The RES Report was required by the 2007 Next Generation Energy act and was filed 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: https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5497544.

were analyzed as sources for generation in each zone in the RES Update Study. The locations of these buses can be seen in Figure 5. The buses studied for the DRG scenario are shown in green in Figure 5. A full list of the buses studied for the DRG scenario can be found in the Minnesota RES Update Study Technical Report.

Table 5 - Assumed Generation Sources by Zone

North Dakota Zone	Southwest Zone	Southeast Zone
Balta	Brookings County	Adams
Coyote	Nobles County	Byron
Ellendale	Fort Thompson	Hazleton
Maple River		
Prairie		

Figure 5 - RES Update Generation Zones and DRG Bus Locations



B. RES Update Study Analysis

The RES Update Study team began with the common base model and assumptions developed for both the Corridor Study and the RES Update Study. The study team analyzed system performance for both summer peak and off-peak load conditions. The newly proposed facilities were tested to carry existing firm transfers, new energy transfers, and possibly some non-firm transfers (to allow room for growth of future firm transfers and non-firm transfers to better allow the best economic use of the generation in that area).

Steady State Simulations

The primary method of analysis for the steady-state (power-flow) simulations was the use of AC contingency analysis in PSS/E (Power Systems Simulator for Engineering).

Power flow analysis under system-intact and outage conditions was done to determine the effect on the electric system of adding the Corridor Study options, one at a time. The analysis simulated approximately 7,000 contingencies. This type of analysis determines the criteria violations caused by the generation additions and transmission options studied.

Initial steady state simulations included analysis of numerous options, including several options that extended into Wisconsin, various 345 kV options throughout Minnesota, North Dakota, and South Dakota, and a new 500 kV line from Winnipeg. Planning engineers assumed that the line from Winnipeg would carry additional generation from Manitoba into the United States. While a new 500 kV line was successful in transporting additional power from the north, such a line does not necessarily result in additional transmission that supports the RES. Transmission from Manitoba does not necessarily transport only hydro generation and in any event for purposes of the Minnesota RES, only small hydroelectric power installations qualify as an eligible energy technology. Hydroelectric power from Manitoba is typically sized in the range of several hundred megawatts.

Based on the results of initial simulations, a group of projects were forwarded for additional analysis under several sensitivities. More information on these projects and the sensitivities studied can be found in Chapter V, Section C (Sensitivity Analysis Results) and Chapter V, Section D (RES Update Project Descriptions and Cost Estimates).

Dynamic Simulations

The primary method of analysis of the dynamic performance of the Corridor Study options was the use of PSS/E's dynamic simulation routines. Using the NORDAGS models discussed in the model-building section earlier in the report, 16 regional faults were modeled to determine the effect of the projects being proposed on the regional transmission grid.

When minor voltage swing violations are observed, a static VAR compensator (SVC) can be used. SVCs are capable of providing dynamic voltage support and responding quickly to fluctuations in voltage. More significant fluctuations in voltage or unstable conditions cannot typically be resolved through the use of SVCs. In addition, when a system already has a significant level of reactive compensation, the effect of adding more compensation is reduced. Another way of saying this is that there is a law of diminishing returns associated with the addition of reactive support.

A description of the dynamic stability implications of the proposed projects can be found in Chapter VI, Section A (Stability Assessment Results).

PROMOD Simulations

The study team worked with the Midwest ISO to perform analyses that tested the performance of the proposed facilities within the Midwest ISO's market dispatch. Short for PROduction MODeling, PROMOD is a software package developed by Ventyx that is capable of modeling the performance of the generation market. It can factor in transmission constraints, manipulate generation dispatch to avoid overloading constrained transmission interfaces, and minimizes the generation cost to do so.

PROMOD is a highly data-intensive program. A small selection of the type of information that is necessary to conduct an effective PROMOD study includes data such as fuel charges, fuel consumption rates for individual generators, possible generation increments for individual generators, and the startup time, shutdown time, and individual unit ramp rates for any generators that participate in a given market dispatch.

In addition, PROMOD is also a highly processor-intensive program. PROMOD uses its generation and transmission information, along with location-specific wind profile data to model the transmission system for every hour of an entire year. The wind farms modeled within PROMOD can be tied to the location-specific wind profile data so neighboring wind farms can theoretically see slightly different wind regimes.

Given the amount of confidential, market-sensitive information that is used in a PROMOD run, Midwest ISO engineers are widely-regarded as having some of the best-available production modeling information in the Midwest. For this reason, their assistance was sought to ensure the PROMOD study was conducted with the best information available.

While PROMOD can provide information such as Locational Marginal Prices (LMP) for various constraints and the value of alleviating that constraint, the information that bears the most relevance to this analysis is that of the production cost savings and load cost savings brought to bear by the projects being examined.

The production cost of a PROMOD study is the cost to produce sufficient generation to meet the demand being modeled. By running a "base case" and comparing the production cost of that case with one that includes the project in question, it is possible to determine the annual cost savings that will be realized by generators. The load cost of a PROMOD study is calculated by multiplying the LMP for each load center by the amount of load in that load center and then summing all the values for the various load centers in the market.

Because utilities operate in an environment that is generally regulated, it is in the best interest of the utility to minimize the cost to deliver its energy. This promotes efficiency of production and minimizes the amount of generators that have to be run at any one time. In general, the production cost calculation within PROMOD tends to reflect more of a regulated market system. A true market system, on the other hand, will seek to minimize the cost observed by the load. When rates of service vary based on the constraints present on the transmission system, a utility will be most interested in what the cost to its loads would be. In this way, the load cost calculation within PROMOD reflects a more market-based system.

Given the mixture of regulated and market-based entities within the Midwest ISO footprint, the Midwest ISO typically considers 70 percent of the production cost savings and 30 percent of the load cost savings when evaluating the economic worth of a project. To maintain consistency with the Midwest ISO's methodologies, the same percentages were used for this analysis.

The PROMOD analysis for the RES Update Study facilities was conducted with the preferred Corridor facilities in service to ensure the most accurate post-project simulations occurred. The results of these analyses can be found in Chapter V, Section D below.

C. RES Update Study Key Findings

Operational Limits with Increased Wind Penetration

The key finding of the RES Update Study is the realization of an operational limit to the extent to which wind penetration can be accepted into the transmission grid in the upper Midwest. In the steady state realm, this limit began to manifest itself as generation in the Twin Cities was turned down in order to enable increasing amounts of wind to be turned on. Some Twin Cities generators are natural gas units that can be turned on and off with relative ease. However, the

Corridor and RES Update studies verified that beyond the renewable generation levels envisioned with the Corridor Upgrade, additional intermittent generation would require the larger fossil fuel generators near the Twin Cities to begin backing down.

This is significant because the fossil fuel plants typically cannot respond to significant changes in load or variable generation sources such as wind. When taken offline, minimum restart times for fossil fuel plants are typically two to three days and not having the units available for that long to deal with fluctuations in wind generation could jeopardize the reliability of transmission service in the upper Midwest.

These findings underscore the need for additional transmission infrastructure as wind penetration increases. If wind penetration is increased to the point that larger generation units near the Twin Cities have to be shut down, additional transmission will be needed to enable the region to import power when wind generation is not sufficient to serve the demand in the area. However, if there is a desire to keep the larger generators near the Twin Cities online to provide increased reliability, additional transmission will be necessary in order for the transmission system to accept the injection of this much power. In other words, ensuring reliable operation of the electric system at increasing levels of renewable generation will require additional transmission outlet capacity.

In addition to the steady state issues identified above, concerns about approaching the region's operational limit for wind penetration were confirmed by the results of the dynamic stability assessment. A stability assessment with the Corridor Upgrade (and associated generation projects) in service showed only minor issues that needed to be addressed. This case contained approximately 4800 MW of wind generation that was applied toward satisfying the Minnesota RES.

A larger-scale stability analysis that included more significant levels of wind penetration was also conducted. This case included 7300 MW of wind generation and several hundred miles of transmission in addition to the Corridor Upgrade. This case is indicative of an out-year Minnesota RES case or how the system might develop if utilities outside the state begin to seek renewable energy purchases within Minnesota.

This larger-scale stability analysis revealed significant dynamic stability issues for the loss of regional transmission lines (such as King – Eau Claire – Arpin) and large generators (such as Sherburne County Unit 3). Larger generators have a stabilizing influence on the regional transmission system because of their large inertia. When regional faults take place, their inertia allows them to absorb swings in voltage and maintain the integrity of the regional transmission system. In the 7300 MW stability case, a substantial portion of the region's generation needs are being served by smaller generators with less inertia. These smaller units are more susceptible to swings in voltage and can easily contribute to the voltage swings rather than damping them in the manner of a large generating unit.

While the transmission examined in this case may be sufficient to integrate the level of wind on a steady state basis, the instability observed indicates that additional transmission facilities are necessary in order to maintain system stability and associated reliable operation with this level of wind generation in service.

The results of the RES Update Study show that caution must be exercised as wind penetration in the upper Midwest surpasses the levels contemplated by the Corridor Upgrade. While there have been numerous steady-state studies performed analyzing increasing levels of wind penetration, the stability assessment described here is noteworthy because the study team believes it is the most extensive publicly-available system stability study to include these levels of wind generation.

RES Update Study Identification of Constraints and Sensitivities

Another key finding of the RES Update Study was the fact that future generation development will be constrained beyond the levels planned by the CapX2020 Group I facilities and the Corridor Upgrade. In other words, the RES Update Study effectively clarified the next group of transmission constraints beyond those addressed by the CapX2020 Group I projects and the Corridor Upgrade and measured the sensitivities of each area of concern. Without improvements to the specific facilities noted, additional generation will be unable to flow to the areas where the energy is needed.

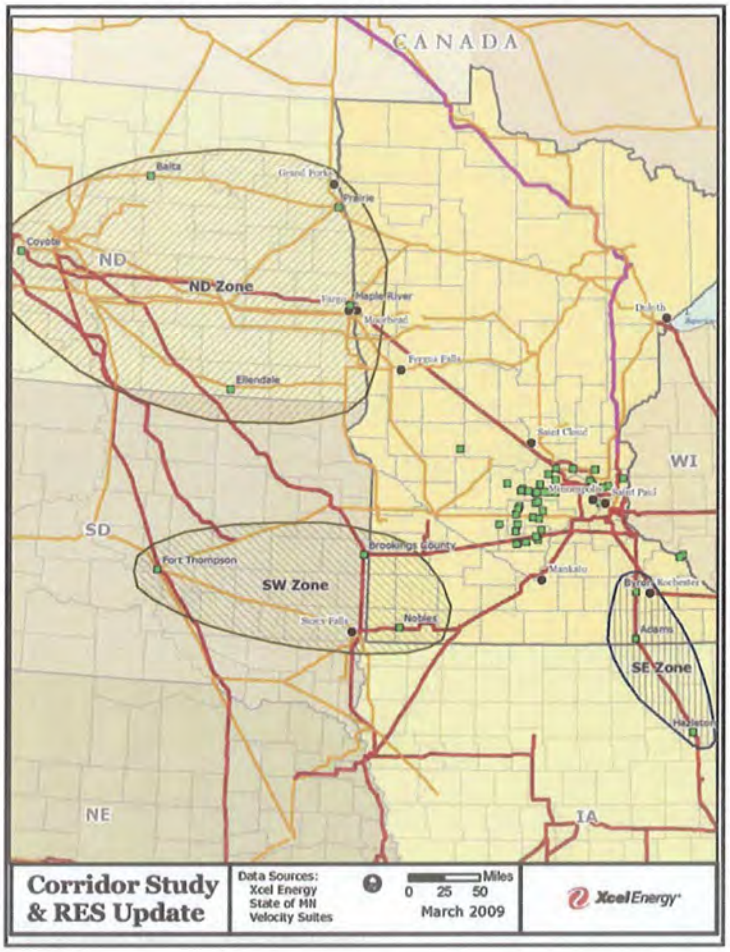
For example, Buffalo Ridge, an area of significant wind development interest in southwestern Minnesota, northwest Iowa, and eastern South Dakota, will be constrained to approximately 1900 MW, generation in southeastern Minnesota will be capped at about 900 MW and the North Dakota Export will be limited to 2080 MW prior to the Corridor Upgrade. Factoring in the Corridor Upgrade, the Buffalo Ridge area would increase to nearly 3,900 MW. Generation in North Dakota receives an indirect benefit from the Corridor Upgrade, but the Southeast Minnesota areas would remain largely unimpacted. Despite the dramatic increase in generation capacity in the Buffalo Ridge area, interest in developing additional generation projects in North Dakota and southeastern Minnesota will remain strong. The RES Update Study lays out the projects that will most beneficially increase those areas.

Results of the RES Update Study also provide support for the Corridor Study and its generation outlet findings. For example the transmission system in western Wisconsin affects the ability to accommodate generation development in Minnesota and points further west.

The study team focused on three popular generation development zones analyzing future limiting transmission facilities and recommending solutions to increase generation outlet from each zone. The RES Update Study investigated the following zones: North Dakota, Southwest Minnesota/South Dakota and Southeast Minnesota. In addition, the study team performed an analysis that relied on the Distributed Renewable Generation Transmission Study to identify sites and transmission upgrades necessary to interconnect approximately 2000 MW of DRG projects. This analysis relied heavily on the study work pioneered in the DRG Study released on June 16, 2008. Details on this study can be found at http://www.state.mn.us/portal/mn/jsp/content.do?subchannel=-536881736&programid=536916477&sc3=null&sc2=-536887792&id=-536881351&agency=Commerce.

Figure 6 identifies the generation zones studied in the RES Update: the North Dakota zone, the Southwest Minnesota/South Dakota zone and the Southeast Minnesota zone. The DRG zone is not shown on the map since these sites are more numerous and spread throughout the state of Minnesota.

Figure 6 - RES Update Zone Map



The RES Update Study shows the next steps necessary to provide a robust transmission system that will allow Minnesota's load serving utilities to meet future Minnesota RES milestones and identifies projects that create outlet for specific generation zones. One observation to these results is that if an individual zone is booming with generation projects to the detriment of development in other zones, the study results will need to be reexamined.

The RES Update Study found that existing infrastructure will constrain generation development beyond the levels illustrated by the CapX2020 Group I facilities. The team identified common limiters impacting Minnesota's transmission system's ability to transmit more energy. The first bottleneck is terminal equipment at White and Sioux City Substations in South Dakota and northwest Iowa. The next is the King – Eau Claire – Arpin transmission line that runs from eastern Minnesota to central Wisconsin. And finally, the study identified the need to upgrade or place additional 345 kV transformers in the Hazleton, Pleasant Valley, Brookings County, Adams and Stone Lake Substations.

The transmission grid in western Wisconsin is primarily comprised of lower-voltage load-serving lines and is not designed for high capacity transfers. Therefore, this part of the regional transmission grid limits the ability to deliver new generation interconnected in Minnesota and points further west.

The lower voltage transmission grid in southeastern Minnesota (161 kV) limits the ability to interconnect generation in southeastern Minnesota and, to a lesser extent, southwestern Minnesota.

The 500 kV system between Winnipeg and the Twin Cities will remain a limiter impeding future generation interconnections in areas west, north, and northwest of the Twin Cities.

Where the Corridor focused on delivery within Minnesota, the RES Update Study expands that scope to ensure that existing barriers to generation delivery within and near Minnesota load centers are addressed. The RES Update Study included sensitivities to the development explored in the Corridor Study and the final recommendations of the Corridor Study were considered when developing the RES Update Study's recommended facilities.

<u>RES Update Study Sensitivity Analysis Results</u>

The RES Update Study not only identified the different facilities' upgrades necessary to increase generation output. The study also investigated the impact the various improvements have on each other in each zone. This sensitivity analysis provided useful data for the RES Update and Corridor Study recommendations.

In the North Dakota zone, the upgrade of the Corridor facilities provides a significant benefit to North Dakota-based generation, however, other transmission facilities are necessary to unlock generation potential within North Dakota. For example:

- The installation of the La Crosse – Madison line results in North Dakota generation having fewer impacts on the 500 kV transmission system. The study team identified the need for a line from La Crosse to the Madison, WI area. Columbia was chosen as a proxy due to the abundance of transmission and its proximity to the Madison area. Joint study work is underway with ATC (American Transmission Company), DPC (Dairyland Power Cooperative), and Xcel Energy to identify the best actual endpoint.
- Extending the Corridor upgrade to Big Stone enhances the benefit to North Dakota generation. This could be accomplished either via the Big Stone II transmission facilities or via the double-circuit line that was studied for the Corridor Upgrade.
- Tying the Twin Cities – Fargo, Twin Cities – Brookings, and Twin Cities – Granite Falls lines together on the western end provides regional reliability

benefits and increases the ability of the lines to back one another up under contingencies.

Figure 7 shows a map of the underlying system limiters that were common throughout most, if not all scenarios studied. A short description of the limiters is provided below.

Figure 7 - Common Underlying System Limiters

- Stone Lake 345/161 kV Transformer – this transformer is located along the recently completed Arrowhead – Gardner Park 345 kV line. The overload generally shows up for contingencies that involve loss of the Stone Lake – Gardner Park. In addition, a 345 kV breaker failure contingency that causes loss of both the Arrowhead – Stone Lake and Stone Lake – Gardner Park line segments causes overload of the King – Eau Claire – Arpin 345 kV line. Adding a second transformer at Stone Lake would eliminate the breaker-failure contingency concern.

- Eau Claire 345/161 kV Transformer – this overload occurs for a stuck breaker contingency on the 161 kV bus at Eau Claire Substation. Alleviating this overload would require either upgrading both 345/161 kV transformers or constructing a breaker-and-a-half scheme on the 161 kV bus at Eau Claire.
- Adams 161 kV Bus – overload of this bus segment occurs due to loss of the Byron – Pleasant Valley – Adams 345 kV line or a 345 kV breaker failure at Hazleton Substation that causes loss of the Hazleton – Adams line. Both of these contingencies force more power through the 161 kV system at Adams.
- White Substation 345 kV Relay Settings – the relay settings at White Substation are set in such a way that flow on the White – Split Rock 345 kV line is limited. This overload occurs for loss of the Brookings County – Lyon County 345 kV line, as this contingency forces power at Brookings County to flow south to Split Rock Substation.
- Sioux City Substation 345 kV Relay Settings – the relay settings at Sioux City Substation are set in such a way that flow on the Sioux City – Split Rock 345 kV line is limited. This overload occurs for loss of the Lakefield – Nobles 345 kV line, as this contingency forces power at Split Rock to flow north to White Substation and south to Sioux City Substation.
- Adams 345/161 kV Transformer – this transformer is located in southeastern Minnesota and its overload mainly occurs for loss of the Byron – Pleasant Valley – Adams line.
- King 345 kV Bus Arrangement – the bus arrangement at King Substation northeast of the Twin Cities currently makes it possible that a single contingency could cause the loss of the King – Chisago, King – Red Rock, and King – Eau Claire 345 kV lines. Loss of King – Eau Claire also initiates tripping of the Eau Claire – Arpin 345 kV line. This contingency was shown to trigger several overloads throughout the system. By adding 345 kV breakers at King Substation, this contingency can be eliminated so only one facility is lost due to any contingency.
- Plymouth – Sioux City 161 kV Line – this overload occurs for loss of the Brookings County – Lyon County 345 kV line, as additional power is forced to flow south through Sioux Falls and Sioux City and then back up to the Twin Cities.

Figure 8 provides a map of the three most common limiters that were deemed to be significant enough to limit additional generation delivery within a given sensitivity. A short description of each limitation is provided below.

Figure 8 - "Stopping Point" Limiters

- Ellendale – Oakes 230 kV Line – this line is the primary limit in cases without the Ashley – Hankinson 345 kV line. The interest in new generation development in the Ellendale area is the primary driver for this line overload.
- Hazleton – Adams 345 kV Line – this line limits generation delivery in a number of cases. Based on commitments made by ITC Midwest, it is anticipated that a new 345 kV line from Hazleton to Salem Substation will be constructed. This helps to provide generation outlet from southeastern Minnesota and northern Iowa. However, at higher levels of generation

loss of 345 kV circuits between the Rochester area and La Crosse or Madison causes significant additional power to flow on the Hazleton – Adams 345 kV line as it attempts to reach the Hazleton – Salem line.

- Sioux Falls – Pahoja 230 kV Line – as generation interest in southwestern Minnesota and the Dakotas increases, loss of the Split Rock – Sioux City 345 kV line will overload the Sioux Falls – Pahoja line. This line runs roughly parallel to the Split Rock – Sioux City 345 kV line and receives much of the flow that is redistributed after the contingency.

For each of the following sensitivity analysis charts, the columns represent the different ways in which the Corridor transmission was modeled in a particular case. The Minnesota Valley – Blue Lake 230 kV column represents the system's performance with the existing 230 kV Corridor. The Hazel Creek – Blue Lake 345 kV Double Circuit column models the Corridor as recommended in the Corridor Study, and the Big Stone – Blue Lake 345 kV Double Circuit column represents the performance of the system if the recommended Corridor Upgrade extends to Big Stone Substation. This system alternative was included due to the burgeoning interest in wind generation projects in the vicinity of Big Stone Substation.

The rows in the tables are various RES Update Study transmission facilities. Within each cell, the first line represents the generation level that can be reached with particular transmission assumptions. The second line represents the facility whose overload represents the system limit. The third line represents the contingency that limits the generation delivery under that scenario.

For example, referring to Table 6, in a case with Maple River – Brookings in service and the existing Minnesota Valley – Blue Lake 230 kV line in service, 490 MW of outlet can be obtained. This is limited by overload of the Ellendale – Oakes 230 kV line for loss of the Center – Jamestown 345 kV line. If you move to the next column, installing the Corridor Upgrade results in 1500 MW of outlet. Again this is limited by overload of Ellendale – Oakes this time for the loss of Jamestown – Maple River 345 kV line.

Table 5 - Sensitivity Analysis for North Dakota Zone

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
Maple River - Brookings	490 MW Ellendale-Oakes 230 Center-Jamestown 345	1501 MW Ellendale-Oakes Jamestown-Maple River 345	2022 MW Hazleton-Adams 345 ECL-ARP & ARR-SLK
Maple River - Brookings Ashley - Hankinson	1049 MW ARR Phase Shifter Base Case	1530 MW ARR Phase Shifter Base Case	2006 MW Hazleton-Adams 345 ECL-ARP & ARR-SLK
Maple River - Brookings Ashley - Hankinson La Crosse - Madison	1440 MW ARR Phase Shifter Base Case	1581 MW ARR Phase Shifter Base Case	2688 MW ARR Phase Shifter Base Case
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	1588 MW ARR Phase Shifter Base Case	1653 MW Hazel-Granite Falls 230 Base Case	2285 MW Sioux Falls-Pahoja 230 SPK-NOB & SPK-SXC 345

In the southwest zone, transmission improvements provide noteworthy results in terms of generation capacity improvement. The largest benefit for this zone occurs with installation of the La Crosse – Madison 345 kV line which crosses from Wisconsin from La Crosse to the Madison area. The 500 kV line does not seem to be as affected as in other zones because the distribution factor of southwestern generation on the 500 kV line is low enough that the 500 kV facilities do not require attention. Distribution factor is the term that defines the percentage of generated power that flows on a certain transmission facility and is often expressed as a percentage of the generator power output.

Table 6 - Sensitivity Analysis with Southwest Zone

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Madison	2572 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345	2435 MW Hazel-Granite Falls 230 Base Case	2645 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Adams - La Crosse La Crosse - Madison	2566 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345	2433 MW Hazel-Granite Falls 230 Base Case	2651 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Lakefield Jct. - Adams Adams - La Crosse La Crosse - Madison	2700 MW Split Rock-Nobles 345 Nobles-Lakefield Jct.	2473 MW Hazel-Granite Falls 230 Base Case	2728 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	1998 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345	2150 MW Hazel Creek 345/230 Parallel Outage	2285 MW Sioux Falls-Pahoja 230 SPK-NOB & SPK-SXC 345

The sensitivity test of the southeast zone showed that the greatest benefit comes from installation of the Corridor Upgrade and the La Crosse – Madison 345 kV line. This results in approximately 3600 MW of generation delivery capability beyond the base case in the model. The southeast portion of the state benefits from a low distribution factor on the 500 kV line and a relatively robust 345 kV and 161 kV transmission system. There is no occurrence of 500 kV facilities in the analysis of increased southeastern zone generation. Given the distance between the southeast portion of Minnesota and Big Stone and the dominant west-to-east transmission flows, southeast Minnesota generation receives limited benefit from the extension of the Corridor Upgrade to Big Stone.

Table 7 - Sensitivity Analysis for Southeast Zone

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Madison	2394 MW Hazleton-Adams 345 Byron-N. Roch. 345	3600 MW Hazleton-Adams 345 Base Case	3682 MW Hazleton-Adams 345 Base Case
Adams - La Crosse La Crosse - Madison	3000 MW	3000 MW	3551 MW Hazleton-Adams 345 Hilltop-N. LAX 345
Lakefield Jct. - Adams Adams - La Crosse La Crosse - Madison	3000 MW		3418 MW Hazleton-Adams 345 Hilltop-N. LAX 345
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	3000 MW	2861 MW Hazel-Granite Falls 230 Base Case	3805 MW Hilltop-N. LAX 345 ECL-ARP & ARR-SLK 345

Additional sensitivity analysis was performed that investigated simultaneously increasing generation in all the zones being considered. This analysis showed that facilities in and around Sioux Falls, South Dakota will require mitigation prior to significant additional generation delivery. It also showed no occurrence of 500 kV facilities because there is enough incremental generation growth occurring in southwest and southeast Minnesota that the generation in North Dakota is not sufficient to cause the 500 kV line to overload. The Broadland – Brookings County line is not particularly helpful in adding generation capability.

Overall sensitivity analysis findings highlighted some high potential projects that have impacts to multiple zones and may merit resolution sooner. The first is the installation of the La Crosse – Madison 345 kV line which provides significant benefit in all cases. The facilities in and around Sioux Falls, South Dakota at the Split Rock substation will also require upgrades. Most of these improvements are necessary due to terminal equipment limitation s and would be relatively inexpensive to complete.

<u>Study Methodology Insights</u>

One additional finding was that the effective use of market-wide dispatch enables the transmission system to be studied more closely with respect to how it is actually used than traditional study methodology.

The North American electrical system is a complex interconnected grid in which power generators are interconnected through many miles of transmission lines comprising a high voltage grid that transports electric power to consumers. The bulk transmission system with limited access points acts like the interstate highway system, moving electric power long distances.

The market-wide dispatch model used for the analysis of this RES Update Study mirrors the way electricity is generated and moves through the system.

Another concern with the traditional or more localized study methodology is that it has the effect of "hiding" transmission violations like low voltage that occur during Midwest ISO market dispatch by not allowing the generation to participate in true market dispatch. The study team sought to ensure adding the generation would not constrain the transmission system with something that is masked by the Midwest ISO market dispatch model. At the same time, some violations can occur that would not normally occur in market dispatch based on increased transmission flows through areas created by traditional dispatch.

Market dispatch methodology better enables generation to interconnect and be delivered by studying transmission projects in the manner they will be used once in operation.

The power system is operated in real-time via security-constrained economic dispatch. What this means is that the transmission system operators work to run the most reliable and low-cost generation units first and then the higher cost generation units as needed to accommodate the electricity demand. This minimizes cost of generation that runs while avoiding contingent system violations. Therefore, the RES Update Study's use of market-wide dispatch provided more accurate results. Generally, higher cost generation is east of Minnesota, lower cost generation is west of Minnesota, so often a west-to-east bias of power flow occurs until facilities within the system limit that bias.

D. RES Update Project Descriptions and Cost Estimates

The projects that were investigated are described below. In addition, some results of various cost analyses are also included. As stated previously, the primary concern of this report is to investigate the cost of the transmission upgrades necessary to create additional generation delivery – just one of the three parts of customer cost of adding new generation. The PROMOD analysis results provide an analysis of the cost to produce enough energy to meet the demand in the model. Not included among these costs is consideration of the additional spinning reserves needed to absorb fluctuations in wind generation levels and power purchase agreement costs. This is an important portion of the cost of renewable energy integration that was not examined here.

La Crosse – Madison Project

As has been mentioned previously, the La Crosse – Madison project concept is being reviewed by engineers at several regional utilities to determine the most effective topology for the proposed facility. For purposes of this study, such a line was assumed to begin at North La Crosse and end at Columbia power plant north of Madison.

This assumption was made with the knowledge that it is difficult to route additional transmission facilities into Columbia Substation. However, given the existing transmission at the Columbia plant, it served as a desirable proxy for the line to avoid dealing with unforeseen transmission constraints at the Madison end of the proposed line that would likely be addressed by any ultimate project configuration. It is the opinion of the study team that any eventual La Crosse – Madison project topology would produce substantially similar electrical results as the proposal that was studied.

From North La Crosse Substation, the assumed project constructed 75 miles of new double-circuit 345 kV line to the existing Hilltop Substation. Expansion of Hilltop Substation to include 345 kV transformation was assumed. From Hilltop Substation, approximately 65 miles of double-circuit 345 kV line was constructed to Columbia Substation.

Figure 9 - Location of the La Crosse – Madison Project

This project has the reliability benefit of providing a parallel electrical path to the King – Eau Claire – Arpin 345 kV line. Based on the results discussed above, the King – Eau Claire – Arpin line has been shown to limit regional generation delivery.

The total cost of this project is estimated at $350 million. This project estimate is indicative only. A significant amount of the facilities in this estimate are owned and operated by ATC. Because of this, the actual project cost could vary from this number.

Table 9 provides a summary of the costs associated with the La Crosse – Madison project when installed with the preferred Corridor facilities.

Table 8 - Costs for La Crosse - Madison 345 kV Line (Including Corridor Facilities)

Description	*Cost*
Project Cost	$700,000,000
Underlying System Cost	$35,000,000
70% Production Cost Savings Offset	($191,000,000)
30% Load Cost Savings Offset	($612,000,000)
Loss Savings Offset	($134,000,000)
Net Project Cost	($202,000,000)

The installed cost of the two projects together totals $700 million. Maximizing outlet for these projects (3600 MW) requires an additional $35 million in underlying system upgrades. A complete list of these projects can be found in the Appendices to the Minnesota RES Update Technical Report.

Analyzing these projects in PROMOD demonstrates significant savings in both production cost and load cost over a similar case without the transmission upgrades. The values reflected in the table above represent 70% of the production cost savings and 30% of the load cost savings. A combination of the two is used to represent the hybrid regulated/deregulated nature of the Midwest ISO market. These proportions are consistent with the Midwest ISO's methods for analyzing projects. Because the base case included the same generators without the transmission upgrades, the savings reflected above represent savings that are wholly due to the addition of the Corridor Upgrade and the La Crosse – Madison 345 kV line.

The production cost and load cost savings of this project are due to the generation delivery capability across a wide area of the upper Midwest. Keeping the new generation within Minnesota limits the amount of generation that can be produced and generally increases the overall production cost.

In addition to the production and load cost savings, a loss analysis was performed. This resulted in a savings of approximately 43.4 MW. The costs in the table reflect the economic value of those savings over a 40-year period. These savings are created largely due to the off-loading of the constrained King – Eau Claire – Arpin 345 kV line.

Considering these costs together, the net project cost – taking into account construction costs as well as savings brought about by new efficiencies in the power system is a savings of approximately $202 million. These costs represent the impact of installing the Corridor Upgrade and the La Crosse – Madison line in tandem. In other words, compared to the post-CapX2020 Group I base case, installing the Corridor Upgrade *and* the La Crosse – Madison project would result in a total net project savings of roughly $295 million.

Comparing the differences between Table 9 and Table 4, the impact of adding the La Crosse – Madison line alone can be determined. This analysis is largely academic, though, as the Corridor Upgrade is necessary in order to achieve a significant increase in generation delivery. Generation throughout southwestern Minnesota and the Dakotas would be constrained by the existing 230 kV Corridor Upgrade unless it is upgraded as recommended in the Corridor Study.

Overall, these results indicate that the $350 million project investment results in new transmission system efficiencies that not only cover the cost of a La Crosse – Madison line but nearly return the full value of its project cost back to the power system in the form of more efficient and less expensive operation.

Fargo – Brookings County Project

The Fargo – Brookings County project is a double-circuit 345 kV line utilizing both new and existing right-of-way between Fargo, North Dakota and the existing Brookings County Substation in South Dakota. The project begins with approximately 60 miles of new double-circuit 345 kV line between Fargo and the existing Hankinson 230 kV Substation. At Hankinson, a new 345/230 kV transformation would be installed to serve as a high-voltage injection point for new generation sourced in North Dakota.

From Hankinson Substation, the existing Hankinson – Big Stone 230 kV line would be removed and replaced with a double-circuit 345 kV line. The total mileage of this segment is 70 miles. In the middle of this segment is the existing 230/41.6 kV Browns Valley Substation. This is a load-serving substation that serves a portion of Otter Tail Power Company load in South Dakota and Minnesota. As part of this project, Browns Valley would be converted to a 345/115/41.6 kV substation. The 41.6 kV load would be served off the transformer tertiary and the 115 kV secondary would be available to serve future load-serving or generation delivery projects.

Extending south from Big Stone, 75 miles of new double-circuit 345 kV line would be built to ultimately connect to the existing Brookings County Substation.

Figure 10 - Location of the Fargo – Brookings County Project

Completion of this project would have the benefit of tying together the Twin Cities – Brookings, Twin Cities – Fargo, and Southwest Twin Cities – Granite Falls lines with a large 345 kV backbone. This development would enhance the reliability of these lines by allowing power to transfer more efficiently between them in case of a system contingency.

The total construction cost of this project is estimated at $550 million. This project was analyzed along with a supplemental project, the Ashley – Hankinson project. A detailed cost analysis can be found along with the Ashley – Hankinson project description.

Ashley – Hankinson Project

The Ashley – Hankinson 345 kV project is a 345 kV spur from eastern North Dakota extending into central North Dakota. The general territory through which this line would pass includes some of the most prominent wind regimes in the upper Midwest.

Where the existing Leland Olds – Groton 345 kV line crosses the Ellendale – Wishek 230 kV line, this project would propose to build Ashley Substation. Currently, the rich wind regime in this area is limited in delivery capability by the 230 kV line that was designed to serve load in the area. Ashley Substation would be a new 345/230 kV substation that would insert a new injection point into the 345 kV transmission system. From there, a 125-mile single-circuit 345 kV line would be constructed along new right-of-way to Hankinson Substation. New right-of-way would be necessary because the existing system in this area is limited by outage of Ellendale – Forman – Hankinson 230 kV line – the only possible double-circuit candidate.

This project is intended to be a supplement to the Fargo – Brookings project, as without the new 345 kV line connecting Fargo with Brookings County, the 345 kV line would dead-end in an already-constrained 230 kV system.

Figure 11 - Location of the Ashley – Hankinson Project

The total cost of the Ashley – Hankinson project is estimated at $175 million.

Table 10 provides a summary of the costs associated with the Fargo – Brookings project and the Ashley Hankinson project when installed together.

Table 9 - Cost of Fargo - Brookings & Ashley Hankinson Projects

Description	Cost
Project Cost	$725,000,000
Underlying System Cost	$45,000,000
70% Production Cost Savings Offset	($253,000,000)
30% Load Cost Savings Offset	($494,000,000)
Loss Savings Offset	($35,000,000)
Net Project Cost	($12,000,000)

The installed cost of the two projects together total $725 million. Maximizing outlet for these projects (1530 MW) requires an additional $45 million in underlying system upgrades. A complete list of these projects can be found in the Appendices to the Minnesota RES Update Technical Report.

Analyzing these projects in PROMOD together with the recommended Corridor Upgrade yields significant savings in both production cost and load cost over an identical case with only the Corridor Upgrade. The values reflected in the table above represent 70% of the total production cost savings and 30% of the total load cost savings. A combination of the two is used to represent the hybrid regulated/deregulated nature of the Midwest ISO market. These proportions are consistent with the Midwest ISO's methods for economic analysis of projects. Because the base case included the Corridor Upgrade, the savings reflected above represent savings that are wholly due to the addition of the Fargo – Brookings and Ashley – Hankinson projects.

The production cost and load cost savings associated with this project are due to the project's ability to unlock the potential for additional wind resources and the alleviation of transmission constraints in North Dakota and western Minnesota.

In addition to the production and load cost savings, a loss analysis was performed. This resulted in a savings of approximately 11.4 MW. The costs in the table reflect the economic value of those savings over a 40-year period.

Taking these costs together, the net project cost – taking into account construction costs as well as savings brought about by new efficiencies in the power system is a savings of approximately $12 million.

A key finding of both the Corridor and RES Update Studies is the need to increase the transmission ties between Minnesota and Wisconsin. Combining the Fargo – Brookings and Ashley – Hankinson projects with the La Crosse – Madison project yields additional savings. Table 11 provides a summary of the costs associated with these three projects together.

Table 10 - Cost of Fargo - Brookings & Ashley - Hankinson Projects with La Crosse - Madison 345 kV Line

Description	*Cost*
Project Cost	$1,075,000,000
Underlying System Cost	$30,000,000
70% Production Cost Savings Offset	($356,000,000)
30% Load Cost Savings Offset	($679,000,000)
Loss Savings Offset	($128,000,000)
Net Project Cost	($58,000,000)

Addition of the La Crosse – Madison 345 kV line increases the project cost by roughly $350 million and simultaneously reduces the underlying system costs by $15 million.

Significant increases in production cost savings, load cost savings, and loss savings are also realized by adding the La Crosse – Madison 345 kV line.

Another benefit that cannot be easily quantified is the benefit of increasing ties to Wisconsin – doing so enables the system to handle greater quantities of variable generation (such as wind). By enabling greater access to both load and generation in Wisconsin, the La Crosse – Madison line benefits the system in Minnesota, North Dakota, and South Dakota by serving as a buffer to absorb fluctuations in wind generation levels.

Considering all the costs together, the net project cost – taking into account construction costs as well as savings brought about by new efficiencies in the power system is a savings of approximately $58 million. As with the case above, to compare the performance of this scenario with the transmission grid as it would exist post-CapX2020 Group I, simply add the net project cost from this scenario with the net project cost achieved with the Corridor Upgrade in Part E of Section IV.

<u>Brookings – Split Rock Project</u>

The Brookings – Split Rock project is a new double-circuit 345 kV line that connects the existing Brookings County Substation to Split Rock Substation. From Brookings County Substation, 45 miles of new double-circuit 345 kV transmission line would be constructed to the existing Pipestone Substation.

One of the significant benefits to this project is that Pipestone Substation, an existing 115 kV substation, would be expanded to become a new injection point into the 345 kV transmission grid. With the addition of 345/115 kV transformation, Pipestone would join Brookings County, Nobles County, and Lyon County as significant injection points that enable generation resources to reach load centers. This expansion becomes increasingly necessary as the amount of wind generation that depends on transformation at Brookings County continues to grow.

From Pipestone Substation, 50 miles of new double-circuit 345 kV line would be constructed to Split Rock Substation near Sioux Falls, South Dakota. The completion of this circuit would expand the reliability benefits of the Fargo – Brookings County project to include the recently-constructed Split Rock – Lakefield Junction 345 kV transmission line. With a Fargo – Brookings County – Split Rock 345 kV transmission line in place, all four 345 kV lines between the Twin Cities and points to the west would be connected.

Figure 12 - Location of the Brookings – Split Rock Project

The total cost of the Brookings – Split Rock project is estimated at $250 million. This project was intended as an extension of the Fargo – Brookings project and, from a cost analysis standpoint, was analyzed as such. Table 12 provides a summary of the costs associated with the Brookings – Split Rock line. Note that these benefits are in addition to the Corridor Upgrade and assume the La Crosse – Madison, Fargo – Brookings, and Ashley – Hankinson projects are in service.

Table 11 - Costs for Fargo - Brookings - Split Rock Project with Ashley - Hankinson & La Crosse - Madison

Description	Cost
Project Cost	$1,325,000,000
Underlying System Cost	$40,000,000
70% Production Cost Savings Offset	($356,000,000)
30% Load Cost Savings Offset	($679,000,000)
Loss Savings Offset	($185,000,000)
Net Project Cost	$145,000,000

The cost of all these upgrades is $1.325 billion and an additional $40 million in underlying system upgrades is needed to achieve the full project outlet (3450 MW). The base case that was used for comparison included the Corridor Upgrade, so the costs reflected above only show the impact of adding the Fargo – Brookings – Split Rock and Ashley – Hankinson projects.

The production cost and load cost savings achieved from the addition of these projects are significant – over $1 billion between the two. In addition, this project achieves the most significant loss savings observed relative to the other Fargo – Brookings – Split Rock projects.

Considering all the costs together, the net project cost – taking into account construction costs as well as savings brought about by new efficiencies in the power system is approximately $145 million.

The most significant benefit to construction of this suite of projects is not financial. The reliability benefit obtained by tying the Twin Cities – Fargo, Twin Cities – Brookings, the Corridor Upgrade, and the Split Rock – Lakefield Junction 345 kV lines together on their western end is significant and cannot be easily quantified through economic analysis. As generation levels increase in Minnesota and the Dakotas, a well designed, robust transmission system will be necessary in order to ensure outlet capability exists for the new generation. In addition, as the stability assessment indicated, significant new transmission additions will be necessary as generation levels eclipse those levels envisioned in the Corridor study.

Lakefield – Adams Project

Lakefield and Adams Substations are currently connected via a single-circuit 161 kV transmission line that serves a number of communities in southern Minnesota. ITC Midwest has announced tentative plans to increase the capacity of this line, but this study assumed the upgrade of this path to double-circuit 345 kV.

From Lakefield Substation, the 161 kV line to Winnebago Substation was replaced with 55 miles of double-circuit 345 kV line. Winnebago Substation was assumed to be upgraded to 345/161 kV in order to ensure it would still be able to serve load in the surrounding area. Leaving Winnebago Substation, the existing 161 kV line to Hayward Substation was replaced with 50 miles of new double-circuit 345 kV line. Similar to Winnebago Substation, Hayward Substation was also converted to include 345/161 kV transformation. Each of these transformations is significant because it also provides a new injection point for generation to reach the high-voltage transmission grid.

From Hayward Substation, the existing Hayward – Adams 161 kV line was replaced with 37 miles of 345 kV double-circuit line.

Figure 13 - Location of the Lakefield – Adams Project

The total cost of this project is estimated at $375 million. This project was analyzed along with the Adams – La Crosse and La Crosse – Madison projects.

A detailed cost analysis can be found along with the Adams – La Crosse project description.

Adams –La Crosse Project

With the significant interest in siting generation in southeastern Minnesota, it was necessary to investigate projects sited to enable additional generation to develop in that area. The Adams – North La Crosse project was designed with that in mind. From the existing Adams 345/161 kV substation, the existing Adams – Harmony 161 kV line was replaced with approximately 35 miles of new double-circuit 345 kV line. This construction would require the expansion of Harmony to include 345/161 kV transformation.

From Harmony Substation, the existing Harmony – Genoa 161 kV line would be replaced with approximately 45 miles of double-circuit 345 kV line. Similar to Harmony Substation, Genoa Substation would be expanded to include 345/161 kV transformation. From Genoa, approximately 20 miles of double-circuit 345 kV line would be constructed to the north, ultimately tying into the existing North La Crosse 345 kV substation.

This project would also have the dual benefit of bringing a new injection point into the La Crosse area. As load in the La Crosse area grows, the existence of a single 345 kV transmission source at North La Crosse will eventually strain the ability of the transmission grid to serve area load for loss of the 161 kV circuit extending south of North La Crosse into the La Crosse area. Inserting this 345/161 kV injection point at Genoa Substation will provide a new injection point remote from North La Crosse Substation.

Figure 14 - Location of the Adams – North La Crosse Project

The total cost of this project is estimated at $300 million. Table 13 provides a summary of the costs associated with the Adams – La Crosse line. Note that these benefits are in addition to the Corridor Upgrade and assume the La Crosse – Madison project is in service.

Table 12 - Cost for Adams - La Crosse Project with La Crosse - Madison Line

Description	*Cost*
Project Cost	$650,000,000
Underlying System Cost	$20,000,000
70% Production Cost Savings (40-year)	($115,000,000)
30% Load Cost Savings (40-year)	($265,000,000)
Loss Savings (40-year)	($167,000,000)
Net Project Cost	$123,000,000

The installed cost of the two projects is approximately $650 million and approximately $20 million of associated system upgrades are necessary to achieve maximum generation delivery (3600 MW).

The production cost and load cost savings achieved with these projects are real, but not as significant as the savings realized by constructing the Fargo – Brookings – Split Rock project. The loss savings are also significant – particularly considering that this case contains less new transmission than the Fargo – Brookings – Split Rock project and still achieves nearly the same level of loss savings. It is worth noting that a significant amount of this savings is due to completion of the La Crosse – Madison project.

Considering all the costs together, the net project cost – taking into account construction costs as well as savings brought about by new efficiencies in the power system is approximately $123 million.

The cost analyses were also performed that added the Lakefield – Adams project to the Adams – La Crosse and La Crosse – Madison projects. Table 14 provides a summary of these costs.

Table 13 - Cost for Lakefield - Adams and Adams - La Crosse Projects with La Crosse - Madison Line

Description	*Cost*
Project Cost	$1,025,000,000
Underlying System Cost	$15,000,000
70% Production Cost Savings (40-year)	($203,000,000)
30% Load Cost Savings (40-year)	($420,000,000)
Loss Savings (40-year)	($225,000,000)
Net Project Cost	$192,000,000

Once again, these results include the Corridor Upgrade as part of the base case, so these costs are indicative of the costs associated with the upgrades named above. Comparing the results of this to the results of the Adams – La Crosse and La Crosse – Madison projects, sharp increases in production cost, load cost, and loss savings are observed. However, the cost increase is not sufficient to offset the cost of the Lakefield – Adams project.

The main benefit to the Lakefield – Adams project is a reliability benefit with some generation delivery associated with it. The existing Lakefield – Adams 161 kV line was primarily designed for load serving and is reaching its capacity. Its upgrade will be necessary in the relatively near future and, from a reliability perspective, it makes sense to tie the southwest Minnesota and southeast Minnesota 345 kV systems together.

Fargo – Split Rock & Lakefield – Madison Projects

The stability assessment performed as part of this study work found that the Fargo – Split Rock and Lakefield – Madison 345 kV lines were necessary to ensure system stability. Given its findings of stability-related concerns at high levels of wind penetration, an analysis of the facilities assumed in the stability assessment was also conducted. Table 15 provides an assessment of the costs associated with those projects.

Table 14 - Costs for Fargo - Split Rock & Lakefield - Madison Projects

Description	*Cost*
Project Cost	$2,000,000,000
Underlying System Cost	$30,000,000
70% Production Cost Savings (40-year)	($500,000,000)
30% Load Cost Savings (40-year)	($791,000,000)
Loss Savings (40-year)	($288,000,000)
Net Project Cost	$451,000,000

With $2 billion in transmission and an additional $30 million in underlying system upgrades, this scenario represents a significant increase in construction cost from the other scenarios analyzed. At the same time, this scenario also demonstrates significant production cost and load cost savings. In addition, nearly $300 million worth of loss savings also provides a significant offset to the cost of the projects.

Despite the increases in production cost, load cost, and loss savings, these projects still represent a net project cost of approximately $451 million.

VI. Corridor Study and RES Update Study Conclusions

A. Corridor Study and RES Update Study Key Results

Upgrade Existing Minnesota Valley – Blue Lake 230 kV line

Both the Corridor Study and the RES Update Study separately confirmed the need for the existing Minnesota Valley – Blue Lake 230 kV line to be upgraded to double-circuit 345 kV. Calling on past study work identifying the Minnesota Valley – Blue Lake 230 kV line as a limiting facility, the Corridor Study independently assessed the most prudent course of action to alleviate this significant system constraint.

As far back as the 825 MW series of projects, the Minnesota Valley – Blue Lake 230 kV line has been viewed as a facility that limits the delivery of energy generated in southwest Minnesota as well as from South Dakota and North

Dakota. The Twin Cities – Brookings line identified the facility as a significant limiter as well. In addition, recent study work focused on identifying projects to increase transfer capability from North Dakota has also identified the Minnesota Valley – Blue Lake 230 kV line as a constraint.

The areas west of the Twin Cities are generally sparsely populated and the transmission grid is, in general, similarly meager. If significant new generation resources are to be developed in locations west of the Twin Cities, from the Buffalo Ridge into North Dakota, upgrade of the Minnesota Valley – Blue Lake 230 kV line to double-circuit 345 kV is necessary. Completion of this upgrade will result in an increase in Buffalo Ridge generation delivery on the order of 2000 MW.

Wisconsin Transmission Limits

In addition to this upgrade, a new high-voltage transmission facility is necessary between La Crosse and eastern Wisconsin to ensure reliable operation and enable full market dispatch of new generation resources. The Corridor and RES Update Studies assumed a termination in the Madison area, but study work is ongoing to determine the precise topology of such a circuit. Southern Minnesota currently only has one high voltage tie between Minnesota and eastern Wisconsin (the King – Eau Claire – Arpin 345 kV line). Together with the Corridor Upgrade, addition of this facility adds as much as 1600 MW of additional capacity to the system - a total of 3600 MW of new generation delivery capability.

The Twin Cities – La Crosse line being pursued as part of the CapX2020 Group I development will bring a new high voltage line to the La Crosse area, but it will not significantly increase bulk transmission ties with other utilities in Wisconsin as it terminates a radial 345 kV line into the 161 kV system in La Crosse.

The La Crosse – Madison 345 kV line is necessary because the King – Eau Claire – Arpin 345 kV line is approaching its operable limit. In the Midwest region, the Midwest ISO operates generators in a market that runs the least-cost units first. Because wind units have no fuel cost, they are typically the first to turn on. This fact, combined with the prevalence of wind within and west of Minnesota, causes a significant west-to-east bias in transmission flow in the region as units in the east are turned down due to their higher cost.

The benefit shown by adding a La Crosse – Madison 345 kV line is consistent with the findings of the Minnesota Wind Integration Study. The Wind Integration Study found that a new 345 kV line stretching into Wisconsin was necessary to enable the Minnesota transmission system to accommodate the levels of wind penetration envisioned in the RES legislation. The Wind Integration Study was one of the inputs considered by the Minnesota legislature when drafting the RES legislation.

Twin Cities Generation Sink Scenario

Another contributing factor is the Twin Cities generation sink scenario studied in the Corridor Study. Importing approximately 2000 MW of generation into the Twin Cities without additional outlet capacity to the east, as was done in the Corridor Study, required significant Twin Cities generation resources to be turned off. Among these was the Sherburne County generating plant operating at its minimum possible level and the High Bridge, Riverside, and Black Dog plants not in operation at all. This result is significant because any increase beyond 2000 MW will require generation at Sherburne County to be shut down. With its restart time measured in days, this would make Sherburne County unable to respond to fluctuations in demand and wind generation. This scenario is not recommended due to a decrease in reliability that would result.

Constructing a new facility between La Crosse and eastern Wisconsin will result in an increase in reliability and ease the significant operational challenge of absorbing the levels of wind being proposed in Minnesota and the Dakotas. As the levels of generation fluctuate, Minnesota will need to rely on its surrounding states to both import and export power to maintain regional system stability. Establishing stronger ties with eastern Wisconsin is an important part of that effort.

In addition to reliability benefits, study work has shown that constructing a La Crosse – Madison 345 kV circuit in conjunction with the Hazel Creek – Blue Lake 345 kV project could increase generation delivery from the region shown in Figure 15 by as much as 3600 MW.