PUBLIC SERVICE COMMISSION OF WISCONSIN

IN THE MATTER OF

JOINT APPLICATION FOR PUBLIC SERVICE COMMISSION OF WISCONSIN

CERTIFICATE OF PUBLIC CONVENIENCE

AND NECESSITY AND WISCONSIN DEPARTMENT OF NATURAL RESOURCES

UTILITY PERMIT

HAMPTON-ROCHESTER-LACROSSE 345 kV TRANSMISSION PROJECT

DOCKET NO. 5 CE 136

DIRECT TESTIMONY OF JEFFREY R. WEBB

ON BEHALF

OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR

JANUARY 9, 2012

Q: Please state your name, title and business address.

A: My name is Jeffrey R. Webb, and I am the Senior Director of Expansion Planning for the Midwest Independent Transmission System Operator, Inc. (hereinafter “MISO”). My business address is 720 City Center Drive, P.O. Box 4202, Carmel, Indiana 46082-4202.

Q: What are your duties with MISO?

A: My duties include directing the evaluation of reliability studies in support of development of MISO Transmission Expansion Plan, and the overall coordination of planning study results into a cohesive regional transmission expansion plan.

Q: Please describe your education and professional background.

A: I hold a bachelor’s degree and a master’s degree in electrical power engineering from Rensselaer Polytechnic Institute. I have also taken a variety of courses and seminars in utility planning and engineering during my career. I have taught courses in circuit analysis, distribution system analysis and electric power system analysis at the Illinois Institute of Technology. In addition, I have served on national and regional groups dedicated to ensuring transmission system reliability. I have served as a member of the Planning Committee of the Mid-America Interconnected Network (“MAIN”) a Regional Reliability Organization that has now merged to form the Reliability First Corporation. I have served as past Chairman of the Transmission Task Force, the Data Bank Group, and Standards Compliance Task Force of MAIN. I have served as a member of the NERC Planning Committee representing the RTO sector, and the NERC Planning Standards Subcommittee (“ NERC PSS”). As a member of the NERC PSS, I have participated in the development of the NERC Reliability Standards related to transmission planning. I facilitate a number of stakeholder groups related to transmission planning at MISO including the Planning Subcommittee and the Regional Expansion Criteria and Benefits Task Force that developed the present transmission investment cost allocation mechanism in place today under MISO Energy Markets Tariff. Throughout my career, I have analyzed and planned electric transmission and distribution systems, with a focus on transmission. I began my professional career working for Commonwealth Edison Company (“ComEd”) in 1976 as a Transmission Planning Engineer. Between 1988 and September of 2000, I held a variety of supervisory and management positions in the bulk power planning area of ComEd, including Technical Studies Supervisor, Bulk Power Planning Supervisor, System Planning Engineer, and

Transmission Planning Manager. As Transmission Planning Manager, I led a department responsible for analyzing the transmission lines, substations, and interconnections that form ComEd's bulk-power transmission network in order to determine when modifications and reinforcements are necessary to maintain adequate, efficient and reliable service to customers. My Responsibilities as Transmission Planning Manager included ensuring that ComEd's transmission grid could meet regional and national adequacy and reliability standards, and whenever appropriate, developing and analyzing cost effective available alternatives for modifications or expansion that best meet those requirements. I have provided testimony before the Illinois Commerce Commission in several dockets involving transmission line certification, before the North Dakota Public Service Commission on a CAPX 345 kV project, and before the Wisconsin Public Service Commission involving certification of the Arrowhead to Weston 345 kV transmission line. I have also provided testimony before the Minnesota Public Utilities Commission regarding the 345kV CAPX projects, including the one in this docket.

Q: What is MISO?

A: The Midwest Independent Transmission System Operator, Inc. (MISO) is a non-profit, member-based organization providing reliability and market services over 49,641 miles of transmission in 11 states and one Canadian province. MISO is governed by an independent eight-member Board of Directors.

Q: What are MISO's responsibilities?

A: As an RTO, MISO is responsible for operational oversight and control, market operations, and planning of the transmission systems of its member Transmission Owners. Among many other responsibilities, MISO also monitors and calculates Available Flowgate Capability ("AFC"), and provides tariff administration for its Open Access Transmission Tariff ("OATT"). MISO is the Reliability Coordinator for its footprint, providing real-time operational monitoring and control of the transmission system. MISO operates a real-time and a day-ahead locational marginal price based energy market in which each market participant's offer to supply energy are matched to demand and are cleared based on a security constrained economic dispatch process. In addition, MISO operates a market for Financial Transmission Rights ("FTR"), which are used by market participants to hedge against congestion costs, and an ancillary services market which provides for the services necessary to support transmission of capacity and energy from resources to load. MISO is responsible for approving transmission service, new generation interconnections, and new transmission interconnections to and within MISO footprint, and for ensuring that the system is planned to reliably and efficiently provide for existing and forecast uses of the transmission system. MISO is the Planning Coordinator for the footprint and performs planning functions collaboratively with its Transmission Owners with stakeholder input throughout, while also providing an independent assessment and perspective of the needs of the transmission system overall.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to describe the planning functions performed by MISO, and the planning process, including a summary of findings based on analyses of the Wisconsin portion of the Hampton-Rochester-La Crosse project (the "Project") within that process.

MISO TRANSMISSION EXPANSION PLAN

Q: What does MISO do as far as its regional planning function obligations under FERC Order 890?

A: MISO adheres to the nine planning principles outlined in Order 890. In so doing, MISO provides an open and transparent regional planning process in which, on an annual basis, MISO calls for, collects and then reviews and evaluates for need and effectiveness the multiple transmission expansion proposals provided by member transmission Owners, Stakeholders, and MISO planning staff. This process results in recommendations for expansion that are critically needed to support the reliable and competitive supply of electric power by this system, and to support energy policy mandates in effect within MISO's footprint. The collective review and analyses is reported on in what is generally known as MISO Transmission Expansion Plan ("MTEP").

Q: Does the MTEP planning activity result in a transmission construction and upgrade plan for the entire MISO footprint?

A: Yes. The Board of Directors of MISO approves updates to the MTEP annually. Since start of operations at MISO, we have produced eight regional plan reports known as MTEP 03, MTEP 05, MTEP 06, MTEP 07, MTEP 08, MTEP 09, MTEP10, and MTEP11. The most recently approved MTEP is MTEP 11 that was approved by the Board of Directors in December of 2011. The approved MTEP 11 Plan can be viewed in its entirety on line at: https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/MTEP11.aspx

Q: What is the purpose of MTEP?

A: The objective of the MTEP is to identify transmission system expansions that will ensure the reliability of the transmission system that is under the operational and planning control of MISO; to identify expansion that is critically needed to support the competitive supply of electric power by this system; and to identify expansion that is necessary to support energy policy mandates in effect within MISO footprint. In addition, the report provides assessments of resource adequacy, analysis of various energy policy scenarios, and development of long term resource forecasts based on those scenarios.

Q: What does it mean for a project to be approved by MISO Board of Directors as a part of the MTEP?

A: In accordance with the *Agreement Of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc. a Delaware Non- Stock Corporation* ("TOA" or "MISO Agreement"), approval of MISO MTEP Plan by the Board certifies the MTEP as MISO's plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities.

Q: Please describe the MTEP process.

A: MISO uses a "bottom-up, top down" approach in developing this plan. The "bottom-up" portion relies on the ongoing responsibilities of the individual Transmission Owners to continuously review and plan to reliably and efficiently meet the needs of their local systems. MISO then reviews these local planning activities with stakeholders and performs a top-down review of the adequacy of and appropriateness of the local plans in a coordinated fashion with all other local plans to most efficiently ensure that all of the needs are cost effectively met. In addition, MISO considers, together with stakeholders, opportunities for improvements and expansions that would reduce consumer costs by providing access to new low cost resources that are consistent with and required by evolving energy legislative policies. Our planning process also focuses on and examines congestion that may limit access to the most efficient resources, and considers improvements that may be needed to meet applicable statutory energy requirements. In the initial stages of the MTEP process, MISO Transmission Owners ("TOs") provide MISO with proposed transmission plans necessary to ensure system performance meets the applicable planning criteria of the TO. The TOs provide detailed descriptions of the projects, anticipated service dates and estimated costs, and summary support and rationale for the need for the projects as well as details regarding alternatives considered. MISO then prepares several models of the power system to assess and determine a recommendation of a coordinated transmission system expansion plan. These models include power flow simulation models, economic generation expansion models, and production cost models. The recommended plan is then subjected to stakeholder scrutiny and feedback to further define and refine it before it is eventually presented to MISO Board for review and approval.

Q: In preparing the MTEP regional plans, what considerations are taken into account by MISO?

A: There are numerous considerations in planning for a regional transmission system, however two considerations are crucial. First, the security of the transmission system must be maintained. That is, the transmission system must be able to withstand disturbances (generator and/or transmission facility outages) without interruption of service to load. This is achieved, in part, by assuring that disturbances do not lead to cascading loss of other generator and transmission facilities. Second, the transmission system must be adequately planned to be able to accommodate load growth and/or changes in load and load growth patterns, as well as changes in generation and generation dispatch patterns without causing equipment to perform outside of design capability. Additional consideration include addressing constraints that limit market efficiency, and providing for expansions that enable energy policy mandates to be achieved.

Q: What planning horizon does MISO consider and employ in its planning process?

A: We plan the system to meet the objectives I've outlined above over a 20 year planning horizon.

Q: What factors come into play in developing transmission plans over this entire planning horizon?

A: All of the considerations I have mentioned are considered to various degrees over the entire planning horizon. However, generally speaking, the short term planning horizon of about five years tends to focus on ensuring system reliability and efficiency in meeting load growth with existing generation, or generation that is emerging as committed generation via the generation interconnection request process under the tariff. Planning for the intermediate (about ten year) and longer term horizons must consider and incorporate generation expansion patterns that are not as definitive as for the earlier periods.

Q: How does MISO plan for this entire period in a manner that will produce near term plans that will be consistent with an efficient and reliable overall plan that also accommodates longer term needs?

A: The planning process is a series of continuous cycles, and we develop plans for these various time periods in parallel, with input and guidance from many stakeholders. The analyses of needs for the short-term planning cycles tends to inform the longer-term planning process, becoming the foundational plans upon which the longer-term plans are developed. In turn, once longer-term planning concepts are developed and sufficiently analyzed to demonstrate preferable options, these preferable options guide the construction of more near-term projects as the planning cycles proceed.

RELIABILITY PLANNING CONSIDERATIONS

Q: What factors must be considered in planning, operating and maintaining an adequate, efficient, and reliable transmission system?

A: A transmission system must have capacity sufficient to meet projected power flows while maintaining required loading and voltage levels and system stability.

Q: How does MISO determine if a transmission system is planned appropriately?

A: An engineering evaluation of the system as a whole, as well as of critical individual system components (transformers, lines, switchgear), under both normal and contingency conditions is regularly performed. Power system simulation models are developed for use in these analyses. Models are checked to ensure that rated capacities are not exceeded and that voltage levels are maintained above the minimums required for safe operation of the system and above the minimums required for supply of adequate voltage to customers. The model system is tested for both generator and voltage stability following select disturbances.

Q: Why is it necessary to provide capacity to meet projected power flows?

A: Several reasons. First, overloaded equipment threatens the system's ability to continue to provide adequate and reliable service to its customers. Overloaded equipment can fail and cause brownouts and blackouts (which, for major transmission components, can be widespread and extended) as well as potentially dangerous conditions. In addition, overloads reduce the service life of equipment and tend to increase the probability of component failure in the future. These are unacceptable outcomes, and why we engage in planning activities to ensure that overloading or other problems do not occur or are minimized.

Q: Why is it necessary to ensure that voltage levels are maintained?

A: Transmission voltages must be maintained within specified tolerances both to ensure that adequate customer voltage is maintained and to ensure that protective relays and other voltage-sensitive equipment operate properly. Proper protective relay operation is crucial to the rapid disconnection of equipment that has failed and may carry extremely high short-circuit currents. If adequate customer voltage is not maintained, electrical equipment may not operate correctly and may be damaged.

Q: Why is it necessary to ensure that system stability is maintained?

A: Certain conditions could cause a generating unit to lose synchronism with the rest of the system or cause bulk power voltages to decline rapidly in an uncontrolled manner. These conditions must be tested for to ensure that the transmission system is strong enough to prevent their occurrence. Without these measures in place, such disturbances could affect the secure operation of wide areas of the inter-connected transmission systems.

Q: Why do you study contingency conditions as well as normal operating conditions?

A: Generating units and major transmission system components cannot be assumed to be in operation 100% of the time. In addition to scheduled maintenance requirements, unscheduled outages can and do occur. Therefore, a level of reliability must be maintained appropriate to the risk of possible system failures.

Q: Does MISO regularly assess the adequacy and reliability of the transmission system within its area?

A: Yes. MISO constantly monitors data on the power flows and voltage levels on all major components of its transmission system. In addition, planners regularly request and collect data on the forecast loads and prepare system models that extend over the planning horizons discussed above.

Q: What, if any, actions are taken based upon these studies?

A: When the data and analysis shows that a change is required, MISO planning staff employees work with member Transmission Owners on transmission expansion plans and assess the options that the Transmission Owners are considering. When a proposed local plan exists that appears to be effective in addressing identified system needs, MISO tests the effectiveness of these plans in meeting applicable planning criteria. MISO then considers other potentially feasible means of meeting the need that are consistent with sound engineering, system planning practices and expected future system development needs. Depending on the nature of the need, there may be many or few such alternative plans. We then determine which of the alternatives are technically and legally feasible, consistent with MISO and the member Transmission Owner's coexistent obligations to provide efficient and reliable service to its customers. Where there is more than one such option, we assess the advantages and disadvantages of the various alternatives and select as the proposed plan the preferred option that would efficiently provide adequate and reliable service to the end use customers.

Q: How is the effectiveness of a proposed project evaluated against system reliability criteria?

A: Among the models prepared are power flow models that are used primarily to identify system contingency conditions that may result in reliability of service below acceptable reliability criteria. These models are generally developed for the five-to-ten year planning horizon. In order to evaluate the need and effectiveness of proposed projects, MISO tests models both without and with the proposed projects to see if there are projected reliability issues that demonstrate the need for possible expansions, and to see if proposed expansions are suitable solutions to issues identified.

Q: What are the standards that govern MISO planning practices to ensure reliable transmission system performance?

A: MISO plans its transmission system in compliance with North American Electric Reliability Corporation (NERC), Regional Entity, and Transmission Owning member transmission planning standards. In addition, planning practices are dictated by FERC Orders 890 and 1000.

Q: Can you briefly summarize the scope of Orders 890 and 1000?

A: Order 890 as I mentioned briefly earlier, is primarily concerned with ensuring that transmission planning takes place in an open and transparent environment where stakeholders to the planning process are engaged in and have opportunities to provide input and comment on the development of local area as well as regional transmission plans. Order 1000 has many requirements but in general these include the requirements to address in planning economic and regulatory policy considerations in addition to the NERC standards for reliability. There are also requirements aimed at ensuring coordination with neighboring planning regions and cost allocation.

Q: What are the NERC transmission planning standards and what do they require?

A: The NERC TPL standards are applicable to transmission planning. There are four TPL standards each with a number of requirements within, that govern planning requirements to ensure reliable transmission system performance. TPL-001 addresses system performance under normal, meaning no contingency, conditions; TPL-002 addresses system performance following events resulting in the loss of a single transmission element; TPL-003 addresses system performance following events resulting in loss of multiple elements; TPL-004 addresses system performance following more extreme events that result in multiple transmission elements, including cascading outage of facilities.

Q: Based on these standards and their requirements, what kinds of contingency events must be studied and what are the associated system performance requirements?

A: All of these standards require that system stability be maintained and that no cascading outages shall occur for the prescribed contingency events, and that facilities remain at all times within applicable thermal and voltage ratings. TPL-002 requires that the system be tested for loss of a single generator, transmission line, or transformer. TPL-003 requires testing for combinations of these events such as loss of a transmission line or transformer following the prior outage of a generator, or another line.

Q: Do the standards require consideration of planned maintenance outages?

A: Yes. When applying the forced outage contingency combinations that I have just described, it is also required to include the planned maintenance outage of any bulk electric equipment at those demand levels for which such outages are performed.

Q: For the TPL-003 events involving loss of two elements such as loss of a transmission line following the typically longer duration outage of a generator, or the loss of a second line while another line is out of service, does the standard permit adjustments including the shedding of firm load after the first event and before the second.

A: Yes, shedding of firm load is permitted provided that the two events are both forced outages, and that such load shedding will result in all voltages and loadings being within applicable ratings after the second outage. If the first event is a planned outage such as the routine maintenance outage of a generator or a transmission line, such planned outages can be accommodated by making system configuration or generator redispatch adjustments to prepare for the next outage which would be a single contingency forced outage. However, load shedding should not be a necessary operating step simply to accommodate a planned maintenance outage while ensuring that voltages and loading remain within limits should a subsequent single contingency occur. If load shedding is planned as the mitigating step for two facilities out of service, and one of those facilities is a planned outage, then that facility cannot be taken out of service for such necessary maintenance.

Q: Has NERC considered any revisions to the standards with regard to whether load shedding should be permitted following the forced outage of a transmission line during the prior forced outage of a generating unit?

A: Yes. TPL-001-2 was adopted by the NERC Board of Trustees on August 4, 2011. This standard is a revision to the existing TPL standards and has been submitted to FERC for approval. The revised standard does not permit the shedding of load for the forced outage of a transmission line following the loss of a generator.

Q: Why do you think the electric power industry has voted to approve this revised system performance requirement that is a part of the new standard?

A: In my opinion this is because the industry has recognized that it is more likely at any given time that a generator will be on outage as compared to a transmission line or transformer simply because of the statistical forced outage rates of generators and the expected duration of those outages. Because a generator can be expected to be on outage for relatively high number of hours during the year, requiring the shedding of customer load for single contingency events during a generator outage is considered an unacceptable level of bulk electric system reliability.

This planning consideration dovetails with operating horizon experience and requirements. In actual operations, NERC operating standards require that the system be adjusted in order to withstand the "next" contingency. This means that after the loss of a single generator, transformer, or line, system adjustments must be made in order to withstand the next event. Therefore if the next event could result in voltages or loadings beyond applicable ratings some action would need to be taken pre-contingency to mitigate the post contingency effects. The result then of planning for load shed as a mitigating step for second contingencies means that in actual operations, customer load may need to be dropped following a single facility outage; and if that is a generator, this could result in more instances of load shedding than the industry considers acceptable.

<u>MISO ANALYSIS OF AREA RELIABILITY NEEDS</u>

Q: Has MISO performed an analysis of the transmission system performance in the La Crosse area?

A: Yes. As a part of MTEP 08, approved by the MISO Board of Directors in December of 2008, MISO studied the system performance in this area against applicable reliability standards, and consistent with the general processes I have described.

Q: Please summarize the MTEP 08 analysis and results.

A: MISO performed reliability analysis of the area affected by the proposed Project by evaluating several different power flow models of MISO transmission system. This analysis was conducted between 2006 and 2008 leading up to the approval of the project in MTEP 08 as I noted above. At that time, we reviewed the projected transmission line loadings and voltage conditions in the La Crosse area for the 2011 summer peak period. That analysis demonstrated that this area can be expected to experience significant reliability problems unless new capacity is introduced into the area. This area is supplied primarily by four 161 kV lines: Alma - Marshland; Tremval - La Crosse; Genoa – Coulee; and Genoa - La Crosse - Marshland. There is 1110 MW of generation in and adjacent to the load area, with 587 MW at Alma to the north, 355 MW at Genoa to the south of Lacrosse, 26 MW of refuse burning units, and 70 MW of operating peaking capacity at French Island in central La Crosse. The La Crosse area load projected for the 2011 summer peak in that study was 492 MW. For this load level, MISO analysis found numerous reliability issues associated with serving this area with the existing system. All of these issues were resolved by introduction of the proposed 345 kV project as a new strong source into the area.

Q: Has MISO updated its projections for system reliability performance in the area?

A: Yes. MISO reviewed the MTEP 08 analysis on a current MTEP 11 model of the 2016 projected system. The current MTEP 11 model of the 2016 MISO system estimates peak load in the area at about 510 MW. These load levels are provided to MISO by our Transmission Owner members and represent a coincident load level for the local area that is somewhat higher than area loads that would be expected to occur coincident with the MISO-wide peak hour.

Q: Can you summarize the results of the updated analysis?

A: Yes. Our analysis confirmed that the proposed project is needed to provide for adequate system loading and voltage levels in the area. Table 1 below indicates line loading levels for a variety of contingent conditions evaluated. Table 2 indicates the voltages in the La Crosse area for various contingencies as well.

Table 1: Thermal Results Summary

2016 Summer Peak		Line Flows (% Rating)	
Critical Facility	**Contingency Event**	**Without Project**	**With Project**
Coulee - La Crosse 161	JPM + Genoa-La Crosse 161	**112%**	90%
Lansing - Genoa 161	Genoa #3 + Alma-Marshland 161	**111%**	91%
Lansing - Genoa 161	Genoa #3 + JPM	**110%**	94%
Coulee - Genoa 161	JPM + Genoa-La Crosse 161	**109%**	92%
Genoa - La Crosse Tap 161	JPM + Genoa-Coulee 161	**105%**	86%
Rochester - Wabaco 161	Genoa #3 + JPM	**105%**	86%
Rochester - Wabaco 161	JPM + Genoa-La Crosse 161	**105%**	83%
Lansing - Genoa 161	Genoa #3 + Alma-Tremval 161	**104%**	90%
La Crosse - La Crosse Tap 161	JPM + Genoa-Coulee 161	**103%**	89%
La Crosse - La Crosse Tap 161	Genoa-Coulee 161	**102%**	86%
Coulee - La Crosse 161	Genoa-La Crosse 161	**101%**	79%
Rochester - Wabaco 161	JPM + Genoa-Coulee 161	99%	83%
Coulee - Genoa 161	Genoa-La Crosse 161	99%	84%
Genoa - La Crosse Tap 161	Genoa-Coulee 161	92%	77%

Table 2: Voltage Results Summary

2016 Summer Peak				
Contingency Event >	**Genoa 3 + Alma - Marshland 161**		**Genoa - La Crosse 161 + Genoa-Coulee 161**	
Critical Facility (per unit voltage)	**Without Project**	**With Project**	**Without Project**	**With Project**
Goodview 1 69 kV	**0.89**	0.95	**0.90**	0.97
Goodview 2 69 kV	**0.89**	0.95	**0.90**	0.98
Winona 69 kV	**0.90**	0.96	0.91	0.98
Coon Valley 69 kV	0.94	0.98	**0.80**	0.97
Krause 69 kV	0.93	0.97	**0.80**	0.97
Sand Lake 69 kV	0.93	0.98	**0.81**	0.97
Greenfield 69 kV	0.94	0.99	**0.81**	0.98
Brice 69 kV	0.93	0.97	**0.81**	0.97
Grand Dad Bluff 69 kV	0.94	0.99	**0.81**	0.98
North La Crosse 69 kV	0.93	0.98	**0.81**	0.97
Holmen 69 kV	0.93	0.98	**0.81**	0.97
Mount La Crosse 69 kV	0.95	1.00	**0.81**	0.98
Holland 69 kV	0.92	0.97	**0.81**	0.97
LaCrescent 69 kV	0.96	1.00	**0.82**	0.98
Onalaska 69 kV	0.95	0.99	**0.82**	0.98
Pine Creek 69 kV	0.96	1.00	**0.82**	0.98
Coulee 161 kV	0.95	0.99	**0.82**	0.98
New Amsterdam 69 kV	0.92	0.97	**0.82**	0.97
Swift Creek 69 kV	0.96	1.00	**0.82**	0.99
Coulee 69 kV	0.96	1.01	**0.82**	0.99
French Island 69 kV	0.96	1.00	**0.82**	0.99
La Crosse 69 kV	0.96	1.00	**0.82**	0.99
La Crosse 161 kV	0.95	1.00	**0.83**	0.99
Monroe County 161 kV	0.97	1.00	**0.83**	0.99
Mayfair 161 kV	0.96	1.00	**0.83**	1.00
Mound Prairie 69 kV	0.97	1.01	**0.84**	0.98
Houston 69 kV	0.97	1.00	**0.85**	0.97
Galesville 69 kV	0.91	0.96	**0.85**	0.97
West Salem 69 kV	0.98	1.00	**0.86**	0.99
Wild Turkey 69 kV	0.98	0.99	**0.87**	0.96

2016 Summer Peak				
Contingency Event >	**Genoa 3 + Alma - Marshland 161**		**Genoa - La Crosse 161 + Genoa-Coulee 161**	
Critical Facility (per unit voltage)	**Without Project**	**With Project**	**Without Project**	**With Project**
Caledonia City 69 kV	0.98	0.99	**0.87**	0.96
Trempealeau 69 kV	0.91	0.96	**0.88**	0.98
Bangor 69 kV	0.99	1.01	**0.89**	1.00

Q: What conclusions do you draw from these analysis results?

A: Similar to the 2008 analysis, we find that projected loading levels in the area will exceed applicable ratings if the project is not installed. Similarly, voltages in the area will be below acceptable levels. For peak load conditions, we project many overload conditions for a line or generator outage during a prior generator outage, as well as overloads for certain single line outages. Some of the line loadings for these conditions are severe enough as to preclude taking maintenance outages of a line or generator at load levels that have been seen in the area historically. In addition, for these conditions we project some voltages below applicable ratings. The two line outage conditions show the overall area weakness. For these conditions voltages are severely low over a wide area. Here again with peak load voltages as low as 80% at some locations, we expect difficulties in performing routine line maintenance without voltages falling below the acceptable 90% level for the next contingency. The widespread nature and low level of voltage following the two line outage condition indicates that there will be risk of voltage instability unless a new strong source is provided in the area. Voltage instability can cause rapid progression of declining voltages throughout a wide area resulting in total collapse of voltages and extensive loss of load. Such events in addition to being a violation of NERC planning standards can cause damage to utility and customer equipment and jeopardize public safety. The seriousness of such events, including potential harm to public health and safety, as well as economic impact on businesses and the community, cannot be overstated. The proposed project is very effective in mitigating all of these issues.

Q: How does the proposed project resolve the issues identified?

A: The project will introduce a strong 345 kV source into the area by terminating the 345 kV North Rochester to North La Crosse line with a 345/161 kV transformer that will tie into this area centrally. With this new source in the area, loading levels on the existing 161 kV lines in the area are 14% to 23% lower under contingency conditions, and voltages are improved across the area on the order of 6 to 17 percentage points. This level of improvement will mean that when the Project is installed loading and voltage levels will be well within capabilities and load growth will be able to be sustained in the area, even at higher growth rates, for many years into the future.

Q: Could the thermal issues in the area be resolved by upgrading the existing lines in the area to higher capabilities rather than by installing the proposed project?

A: Yes this could be done. However, because we see both thermal loading issues and depressed voltages in the area this indicates that the area supplies are no longer capable of adequately supporting the area and a new strong source should be introduced. Rebuilding the existing lines in the area will not reduce the risk of inadequate voltages and potential for voltage collapse in the area, and therefore would be an imprudent investment. In addition, as we observed in our 2008 analysis, the amount of rebuild that would be required and the lack of robustness of this solution in terms of its ability to sustain area growth into the future compared to the proposed project make that alternative inferior. Further, within the next 10 years as more wind generation in the MISO footprint comes online, additional overloads in the region are observed without the 345 kV Project that would not be addressed by the rebuilds of the lines in this area.

Q: Could voltage issues be resolved merely by installing capacitor banks at the existing substations in the area?

A: No. Because of the number of substations in the area that experience voltage degradation under contingency conditions, as load in the area increases, the necessary capacitor bank installations in the area would likely exceed physical locations to install them. In addition, at higher area loads the existing system is subject to voltage instability. Under such conditions, resolving instability by the installation of capacitor banks is ill advised because it can raise voltages without significantly extending the stable loading point. This can increase the risk of voltage collapse and wide-area loss of load because system operators have less ability to see an approaching voltage emergency.

Q: Could thermal and voltage issues be resolved by operation of the French Island generation?

A: We considered the effect of operating the oil fired peaking units at French Island. One of these units is currently mothballed and we have no indication that the unit will be available for operation. Therefore we considered the possible operation under contingency conditions of Unit 4 at French Island. However, this option will not relieve all of the overload conditions identified in the area for projected 2016 conditions and beyond. In addition, reliance on the contingency operation of a single generating unit to ensure reliability is contrary to MISO planning business practices, because of the relatively higher probability of the unavailability of generation due to forced outages, or to possible retirement of older generating units. In the case of the French Island generators, these units are 37 years old, and operational records supporting their dependability are sparse in that they have operated with a capacity factor of a mere 0.2% in the last three years.

INTEGRATION WITH REGIONAL PLAN

Q: How does the proposed project fit into the MISO's long-range planning concepts?

A: The Project was recommended and approved by MISO in 2008 based on fundamental near-term local reliability needs as the primary drivers for the Project. As such, the continuing development of the regional MISO plan have included this project as a part of the base plans upon which other near and longer term plans have been analyzed and developed. Since the project's inclusion as a part of the recommended regional plan developed collaboratively with stakeholders and approved by the MISO Board of Directors in 2008, three years of planning has progressed that has expected this project to be a fundamental part of the regional development plans. While the Project is driven by the load serving needs in the La Crosse area, it extends across the Minnesota-Wisconsin interface that has historically been limited by the few 345 kV transmission lines available to move power from the western part of MISO to the remainder of the market. There have been times in the past when available generation capacity in the western MISO region have been unable to be accessed to supply generation deficient areas of the market. The Project when coupled with other projects in the currently approved MTEP 11 regional plan will enhance the ability of grid to provide access to the most cost effective generation in all hours and access critically needed generation during times of shortage.

Q: Is access to wind resources outside Wisconsin a factor in planning and design of this project?

A: Not specifically. However, without the project, planned wind additions to the system will still occur both through the generator interconnection process and the renewable portfolio standards planning that will impact grid flows on a region-wide basis, including possible line overloading in the La Crosse area. The proposed project works in concert with regional system development to ensure continued reliable system performance in this area.

Q: Please describe the Multi-Value Project (MVP) portfolio of MISO and how it relates to this project.

A: The MVP portfolio is a group of 345 kV projects distributed across the MISO grid that enables the reliable delivery of the aggregate of current state Renewable Portfolio Standards within MISO, and provides for economic benefits in excess of the portfolio costs primarily by reducing production costs. The portfolio was approved for implementation by the MISO Board of Directors in 2011. The Hampton-Rochester-La Crosse project, having been approved in 2008, along with many other projects across the grid, is considered a part of the base case upon which the MVP portfolio is built.

Q: What is the impact on the MISO Regional Plan if a state commission does not approve a project that has received MISO approval?

A: The purpose of the very extensive planning functions of MISO are to involve all stakeholders in a process that will derive the most cost-efficient expansion plan that will meet local and regional needs for reliability, optimize access to economical power resources and deliver other important values that benefit the ultimate consumer and society. The MTEP amounts to the design of a very complex machine that will serve both short- and long-term needs of the electrical grid. Rejection by a state of a key element of the expansion plan, especially a 'backbone' element designed for its reliability attributes, could require considerable re-design involving possible delay, additional expense and impacts to the reliable addition of new generation supplies, and service to load. There would likely be repercussions among other state commissions, particularly in states that would be asked to be the site of alternate transmission facilities.

Q: More specifically, what would be the system impacts if the proposed Project were not constructed as planned?

A: In the context of this project, rejection by Wisconsin would jeopardize the ability in the short-term to supply load reliably to the local La Crosse area, and in the long-term the reliability and efficiency of the grid more broadly. There would be substantial overloading during off peak conditions on the transmission system in Wisconsin, Minnesota, and Iowa as generation required to meet Renewable Portfolio Standards (RPS) are delivered to load throughout the MISO region. An analysis of the projected 2021 system, when full RPS requirements are in place, shows that without the proposed Project, 24 different transmission facilities would be overloaded or loaded to within a few percent of emergency capability for any of 20 single contingency conditions or 26 events involving forced outages during the prior outage of another facility. All these facilities will operate within applicable ratings with the addition of the Project.

Q: Given the results of MISO planning studies that you have outlined in your discussion, how would you summarize the MISO recommendations for the Project?

A: We believe that the Project as proposed by the Applicants is a necessary project that meets the local load serving needs of the system in the La Crosse area and that also fits well as a component of the MISO plan for the continued development of a reliable and efficient regional transmission system.

Q: Does this conclude your testimony?

A: Yes it does.