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May 12, 2010

Mr. Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
600 E. Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480

RE: Pre-filed Direct Testimony of Jeffrey R. Webb
Otter Tail Power Company & Northern States Power Company
Advance Determination of Prudence — CapX2020 Group 1 Application
Case Nos. PU-09-676 and PU-09-678

Dear Mr. Nitschke:

Enclosed for filing in the above-entitled matter are the original and seven copies of the Direct Testimony of Jeffrey R. Webb on behalf of the Midwest Independent Transmission System Operator, Inc., along with an Affidavit of Service by Mail and E-Mail.

Sincerely,

Keith L. Beall

KLB/elb
Enclosures
Cc: See Affidavit of Service by US Postal Service and E-Mail

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Pre-filed Direct Testimony of Jeffrey R. Webb
Midwest Independent System Operator
Keith Beall, Senior Corp. Counsel

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STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Otter Tail Power Company **Advance Determination of Prudence -** **Application CapX2020 Group 1**	**Case No. PU-09-676**
Northern States Power Company **Advance Determination of Prudence –** **Application CapX2020 Group 1**	**Case No. PU-09-678**

PRE-FILED DIRECT TESTIMONY

OF

JEFFREY R. WEBB

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

May 12, 2010

DIRECT TESTIMONY OF JEFFREY R. WEBB

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

A: My name is Jeffrey R. Webb, and I am the Director of Expansion Planning for the Midwest Independent Transmission System Operator, Inc. (hereinafter the "Midwest ISO"). My business address is P.O. Box 4202, Carmel, Indiana.

Q: What are your duties with the Midwest ISO?

A: My duties include directing the evaluation of reliability studies in support of development of the Midwest ISO 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 the Midwest ISO 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 the Midwest ISO 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, 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 these same CAPX transmission facilities.

Q: What is the Midwest ISO?

A: The Midwest ISO is the nation's first Federal Energy Regulatory Commission ("FERC") approved Regional Transmission Organization ("RTO"). It encompasses approximately 1.1 million square miles of member transmission systems from Manitoba, Canada to Kentucky and from western Pennsylvania to North Dakota.

Q: What are the Midwest ISO's responsibilities?

A: As an RTO, the Midwest ISO is responsible for operational oversight and control, market operations, and planning of the transmission systems of its member Transmission Owners. Among many other responsibilities, the Midwest ISO also monitors and calculates Available Flowgate Capability ("AFC"), and provides tariff administration for its Open Access Transmission Tariff ("OATT"). The Midwest ISO is the Reliability Coordinator for its footprint, providing real-time operational monitoring and control of the transmission system. The Midwest ISO 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, the Midwest ISO 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. The Midwest ISO is responsible for approving transmission service, new generation interconnections, and new transmission interconnections to and within the Midwest ISO footprint, and for ensuring that the system is planned to reliably and efficiently provide for existing and forecast uses of the transmission system. The Midwest ISO 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 the Midwest ISO, and the planning process, including a summary of findings based on analyses of the proposed CapX facilities within that process. In addition, my testimony describes the impact of the proposed CapX facilities on regional system performance.

MIDWEST ISO TRANSMISSION EXPANSION PLAN

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

A: The Midwest ISO adheres to the nine planning principles outlined in Order 890. In so doing, the Midwest ISO provides an open and transparent regional planning process in which, on an annual basis, the Midwest ISO calls for, collects and then reviews and evaluates for need and effectiveness the multiple transmission expansion proposals provided by member transmission Owners, Stakeholders, and the Midwest ISO 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 the Midwest ISO footprint. The collective review and analyses is reported on in what is generally known as the Midwest ISO Transmission Expansion Plan ("MTEP").

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

A: Yes. The Board of Directors of the Midwest ISO approves updates to the MTEP annually. Since start of operations at the Midwest ISO, we have produced six region plan reports known as MTEP 03, MTEP 05, MTEP 06, MTEP 07, MTEP 08, and MTEP 09. The most recently approved MTEP is MTEP 09 that was approved by the Board of Directors on December 3, 2009. The approved MTEP 09 Plan can be viewed in its entirety on line at: http://www.midwestiso.org/publish/Folder/254927_1254c287a0c_-7e5f0a48324a?rev=1.

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 the Midwest ISO; 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 the

Midwest ISO footprint. In addition, since February 3, 2006[1] the Midwest ISO tariff has provided for the regional and subregional allocation of the costs of transmission expansions that meet the tariff requirements for such cost sharing. As such, each MTEP is required to set forth the appropriate cost sharing provisions applicable to each expansion project that is accepted and approved by the Midwest ISO Board of Directors.

Q: What does it mean for a project to be approved by the Midwest ISO 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 "Midwest ISO Agreement"), approval of the Midwest ISO MTEP Plan by the Board certifies the MTEP as the Midwest ISO'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: The Midwest ISO 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. The Midwest ISO then reviews these local planning activities with stakeholders and then performs a top-down review of the adequacy of and appropriateness of the local plans in a coordinated fashion with all

[1] The FERC approved the Midwest ISO RECB I proposal on February 6, 2006 in Docket No. ER06-18-000 (114 FERC ¶ 61,106 (2006)).

of the other local plans to most efficiently ensure that all of the needs are cost effectively met. In addition, the Midwest ISO 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 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, the Midwest ISO Transmission Owners ("TOs") provide the Midwest ISO 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. The Midwest ISO 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. This recommended plan is then subjected to stakeholder scrutiny and feedback to further define and refine it before it is eventually presented to the Midwest ISO Board for review and approval.

Q: In preparing the MTEP regional plans, what considerations are taken into effect by the Midwest ISO?

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. In addition to these two crucial considerations a third consideration is the identification of transmission constraints that may otherwise limit access to potential future generation development scenarios, along with devising and implementing solutions to those constraints.

Q: What planning horizon does the Midwest ISO consider and employ in its planning process?

A: We plan the system to meet objectives I've outlined above in the (i) short (1-5 year); (ii) intermediate (6 to 10 year); and (iii) long-range (10 to 20 year) planning horizons.

Q: What factors come into play in developing transmission plans over each of these planning horizons?

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 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 and longer term horizons must consider and incorporate generation expansion patterns that are not as definitive as for the earlier periods.

Q: How does the Midwest ISO 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 work the development of plans for these various time periods in parallel, with input and guidance from many stakeholders. Results of analyses of needs for the short-term planning cycle 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.

Q: Please describe the Midwest ISO efforts to develop a long range transmission plan for the region?

A: This effort is underway and has been since late 2006. We described the evolving planning process in our MTEP 06 report[2] and have been working with stakeholders to develop long-term planning concepts that are based on several different possible "futures". These futures differ in certain basic assumptions that could impact decisions about the most prudent transmission expansion that should be developed to most efficiently and reliably deliver future generation to meet future demand levels.

[2] The MTEP 06 can be viewed at: http://www.midwestiso.org/publish/Folder/3e2d0_106c60936d4_-75230a48324a?rev=2

Multiple possible futures have been developed, and are reviewed and modified over time with input from stakeholders including each of the respective state regulatory commissions. Among the variables that help to define these futures are: 1) explicit legislative or regulatory requirements for resource portfolios; 2) capital costs of resource technologies; 3) load and energy growth forecasts; 4) fuel price and availability; 5) environmental costs and initiatives; and 6) economic conditions such as inflation, discount rates, wind credits etc. Preliminary transmission concepts have been developed that are postulated to be necessary and sufficient to meet the projected demand, generation fuel mix that is economic and meets regulatory assumptions, and generation siting assumptions. Each of these concepts are currently being evaluated for relative value in terms of energy costs, and performance in reliably delivering projected generation to load under the various future scenarios.

The CapX2020 Projects

Q: How do the CapX2020 projects that are the subject of this Docket fit into the Midwest ISO's long-range planning concepts?

A: These four projects fall into what we would call the short to intermediate-term planning horizons, meaning that they will be needed within the next 5 to 7 years. In addition, there are fundamental near-term local reliability needs that are the primary drivers for three of the four projects, and the fourth is needed to reliably deliver new generation developments for the near to intermediate-term as well. As such, in developing our long range planning concepts we have included these projects as a part of the base plans upon which the longer term plans are being developed and analyzed.

Q: Do the longer-term conceptual plans that have been developed to date indicate that any of the CapX projects should be built any differently than as being proposed?

A: No, they do not. Because the CapX facilities have been shown to be needed as soon as they can be constructed to support continued reliable system performance, they have been considered as pre-requisite infrastructure to the longer term regional plans under consideration. Moreover, the CapX facilities are consistent with conceptual plans being developed in long range planning studies such as the Regional Generation Outlet Study (RGOS).

Q: What is the status of the CapX projects that are the subject of this docket with respect to the MTEP regional plan?

A: These projects were introduced to the regional planning process in MTEP 05, which had a planning horizon through the summer peak of 2009 and which was published in June of 2005. They were described as proposed plans in MTEP 05 that were expected to have a service date beyond the 2009 planning horizon. The process required that they be analyzed to verify their need and final design. They were included again in MTEP 06 and MTEP 07 which provided recommended regional plans for the years 2011 and 2013 respectively. In MTEP 06, the Bemidji 230 kV line project was approved by the Midwest ISO Board of Directors (BOD) as a part of the regional plan[3]. In MTEP 07[4] the Fargo, La Crosse, and Brookings projects

[3] The Midwest ISO is required as part of its FERC Order 890 requirements to pursue and establish a regional transmission plan.

[4] The Midwest ISO MTEP 07 Plan was approved by the Board of Directors and published December 2007.

were listed as Appendix B projects meaning that full analysis of the projects had not yet been completed and the projects were not yet being recommended to the Midwest ISO BOD for approval. The Fargo and La Crosse projects were recommended to the Midwest ISO BOD for approval in MTEP 08 and were thereafter approved by the BODs as part of MTEP 08 in December 2008.

Q: What is the status of the Brookings project?

A: The analysis of the Brookings project was incomplete at the time of MTEP 08 and thus it could not be presented and recommended for BOD approval. The Owners described in a letter received on November 14, 2008 that retention of this project in Appendix B[5] would allow time for the project's construction configuration to be finalized by studies that were underway at that time by the sponsoring utilities and by the Midwest ISO. In addition, a significant function of the Brookings project is to provide outlet for a significant amount of additional renewable generation. Cost treatment for such projects has been the subject of considerable stakeholder deliberations over the past two years. For example, the Upper Midwest Transmission Development Initiative ("UMTDI") sponsored by the governors and utility regulators in Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin; the Cost Allocation and Regional Planning ("CARP") group of the Organization of Midwest ISO states; as well as the Reliability Expansion Criteria and Benefits ("RECB") Task Force have each been analyzing policy, planning, and assessing cost allocation issues for regional transmission during this period of time. As noted

[5] [Appendix B is the portion of the MTEP process that provides a listing of proposed projects that are known to be a solution to an identified system expansion need.].

above, the MTEP process requires that projects presented and considered for approval by the BOD must be classified with respect to cost allocation. Therefore, because the actual cost treatment of the Brookings project was not yet certain at that time, it was decided the appropriate action was to defer the request for approval until cost allocation policy decisions and potential tariff revisions impacting the treatment of this project were clarified.

Q: In your opinion, have these lingering issues related to the Brooking project been resolved to the point that it can be presented for approval in the near future?

A: Yes, in part. The Applicants have determined that the most cost effective design for the Brookings line is for the line to be built in a double circuit compatible configuration and approximately half of the line will be initially constructed as double circuit. The Midwest ISO supports this decision. With respect to the policy decisions and supporting tariff provisions that would provide the required certainty regarding the cost allocation treatment of this line, the Midwest ISO is finalizing these provisions in anticipation of a July 15, 2010 filing with the Federal Energy Regulatory Commission ("FERC"). In that filing, it is anticipated that the Midwest ISO will request that the FERC apply the regional cost sharing provisions to any applicable transmission projects approved subsequent to the filing date. It is further anticipated that these regional cost sharing provisions would then meet the cost allocation prerequisite to allow the Brookings project to be considered under the MTEP process.

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 voltage levels and system stability.

Q: How do you determine if a transmission system meets these criteria?

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 (conditions where one or more system components are out of service) must be 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 severe 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. Obviously, these are unacceptable outcomes and thus why we do planning so that such 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 relays and other voltage-sensitive equipment operate properly. Customer voltage is dependent on a number of variable factors, which include transmission voltage level, load magnitude, and load power factor.

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 severe contingencies, while unlikely, must be tested for to ensure that the transmission system is strong enough to prevent their occurrence, or that in such instances protective systems act to regain control of the system. 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 number of customers at risk to possible system failures, balanced by providing service at a reasonable cost. For example, in accordance with the NERC standards, the transmission system must, at a minimum, continue to operate adequately with any single line or transformer in an area out of service. In addition, where the behavior of the transmission system in an area is heavily dependent on the output of a particular generating unit or units, it is necessary to consider the ability of the system to continue to operate when those generating unit are unavailable.

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

A: Yes. The Midwest ISO 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, Midwest ISO 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, the Midwest ISO tests the effectiveness of these plans in meeting applicable planning criteria. The Midwest ISO then considers other potentially feasible means of meeting the need that are consistent with sound engineering and system planning practices. 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 the Midwest ISO 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, the Midwest ISO 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. Similar tests are applied to any alternative proposals until the preferred alternative is selected.

MIDWEST ISO ANALYSIS OF AREA RELIABILITY NEEDS

Q: Has the Midwest ISO performed an analysis of the need and effectiveness of the CapX2020 projects that will support the inclusion of these projects into the regional plan?

A: Yes, an analysis has been performed that is consistent with the general processes and descriptions provided above.

Q: Please describe that analysis.

A: The Midwest ISO performed reliability analysis of the area affected by the proposed projects by evaluating several different power flow models of the Midwest ISO transmission system. This analysis was conducted between 2006 and 2008 leading up to the approvals of the proposed projects in MTEP 06 and MTEP 08 as I noted above.

Q: What assumptions were applied about generation, load and system topology in those models?

A: Modeled generation included existing generators plus any new generators that had proceeded through the Midwest ISO generation interconnection queue process and had executed Interconnection Agreements. The Load that was modeled was provided by the Midwest ISO Transmission Owners through power flow models of their respective systems.

BEMIDJI 230 KV PROJECT

Q: What did the study show with respect to the Bemidji proposed transmission project?

A: Analysis of the upper Red River Valley area during the MTEP 06 study period revealed a large number of contingent conditions that could lead to serious loss of load in the area unless the transmission system was upgraded. The Red River Valley area is geographically large with limited local generation resources. Serious voltage degradation occurs for hundreds of combinations of line loss events which fall within the NERC reliability standards testing protocols.

Q: How would system performance standards be maintained without the proposed Bemidji project?

A: Significant shedding of load would be required to avert voltage instability under any of these many contingent conditions.

Q: What alternatives to the Bemidji project were considered?

A: Several alternative ways of providing a new line source into the area were considered and evaluated, but each of these were found to be more costly than the proposed solution and not as effective.

TWIN CITIES TO FARGO 345 KV PROJECT

Q: What did Midwest ISO studies show with respect to the Twin Cities – Fargo proposed transmission project?

A: Our studies evaluated three general load serving area along the path of this proposed line; the Red River Valley Area ("RRV Area"), the Alexandria Area, and the St. Cloud Area. In the RRV Area our models demonstrated that under peak load conditions, and absent the construction and operation of the Twin Cities – Fargo line, there are numerous contingency conditions involving the forced outage that will result in loadings on other existing facilities beyond their safe design capability. In addition, other conditions will result in transmission level voltages below design criteria, and for certain conditions could result in voltage instability with resultant wide-area loss of load. Each of these conditions fall within the conditions prescribed by the North American Electric Reliability Council ("NERC") to be tested for and for which the system should be designed to maintain stable operation.

Q: What kind of problems did the Midwest ISO identify in the Red River Valley area?

A: The Red River Valley is a winter peaking area that relies on power transported into the area on the single Jamestown-Maple River 345 kV line and other 230 kV transmission lines in the area. The Midwest ISO analyzed the loss of the single 345 kV line supporting the area at Maple River near Fargo, along with one of these 230 kV lines and found that this condition could lead to an unstable decline in voltages in the region, with the potential for uncontrolled loss of large amounts of load across the region.

Q: How does the proposed line resolve these conditions?

A: The proposed project provides a second 345 kV supply to the Maple River 345 kV bus in the Fargo area, so that the system will remain secure for contingent loss of the single existing 345 kV supply to the area.

Q: **Were alternative transmission upgrade solutions considered?**

A: Yes. The addition of voltage support equipment in the area such as capacitor banks were also reviewed and considered. However, the area already has a very large amount of such voltage support devices. When a system is so heavily compensated with such support devices, it can become susceptible to voltage collapse without much advance ability or warning of the collapse. Our analyses indicated that by 2016, unacceptable voltage instability could occur. A system in this state is sometimes referred to as voltage “brittle” and is a concern, because operators may have little indication that there is a critical voltage condition existing and be unable to take appropriate action. In addition to considering the addition of capacitors in the area, the Midwest ISO considered the addition of a second 230 kV line between the Boswell, Wilton, and Winger substations. This line addition was estimated to cost about $161 M and would not provide any relief to other areas along the route **of the proposed line such as in the Alexandria and St. Cloud areas.**

Q: Please describe the reliability issues in the Alexandria area that the Midwest ISO identified would also be resolved by the proposed transmission line.

A: The Alexandria area is described electrically by the demand at 12 substations in and around Alexandria. This area is served by three 115 kV transmission lines: Inman to Elmo; Douglas County to Long Prairie, and; Grant County to Elbow Lake. The Midwest ISO looked at the conditions projected for this area over the short to intermediate planning horizon. Midwest ISO analysis of this area showed that within the next few years, there could be severe line overloads as high as 154% of design capability, and critically low voltages of 52% of design in this area for loss of two of the three 115 kV lines I mentioned. These conditions will worsen as load grows in the area. At these voltage levels, service to the load in the area could not be sustained.

Q: How does the proposed Twin Cities to Fargo line resolve the reliability problems identified in the Alexandria area?

A: The project extends a 345 kV line supply from Monticello through St. Cloud to Alexandria, and then continues this line to connect to the Fargo area 345 kV substation. At the Alexandria substation, a new step down transformer will be installed that will directly inject into and support the heavily stressed 115 kV system in the area.

Q: After the project is installed, what are the resulting loading and voltage levels on the Alexandria area 115 kV lines?

A: For the worst single line loss condition I described, the post-project voltage is increased from 89.5% to 100% of nominal. For the double line outage condition line loadings are reduced from 160% to under 65% of rating, and voltage is improved from 47% to 100% of nominal, providing a more secure system and margin to accommodate load growth in this area.

Q: Did the Midwest ISO consider alternative solutions to resolving the Alexandria area reliability issues you identified?

A: Yes. Redispatch of generation is not an option since there is very little generation available in the area to support the load. We considered the addition of capacitor banks in the Alexandria area as a means of improving voltage conditions. We also considered additional support to the area by extending new 230 kV lines into the area. None of these alternatives provided adequate resolution to the voltage and loading problems anticipated for the Alexandria area.

Q: Are there any other reliability issues needing resolution for which the proposed Twin Cities to Fargo line provides the best solution?

A: Yes there are. The St. Cloud area is vulnerable to a number of different contingency conditions that can cause overloading of existing supply lines, low voltage conditions, and loss of load service. Under the present configuration at the Granite City substation, if there was a loss of the Benton County to Granite City tower line involving both circuits, the St. Regis load of approximately 89 MW would be automatically isolated from supply, and in addition, the St. Cloud to Sauk

River line would overload to 133% of rating. Lesser overloads would also occur on three other 115 kV lines between St. Cloud and W. St. Cloud and between W. St. Cloud and Granite City. Low voltage will also occur on several 115 kV buses, for example, the Crossroads 115 kV bus would have a voltage of 86.8% of design. If the Granite City substation was re-configured such that the St. Regis load could be maintained for this outage, this additional load during the contingency condition would cause line overloads approaching 233% of rating, unless an additional source of power is introduced into this area. Obviously, none of these are acceptable conditions.

Q: Are there other conditions of concern in the St. Cloud Area?

A: Yes. We also project that for near-term conditions, in the event of the loss of two Benton 230/115 kV transformers the St. Cloud to Wakefield 115 kV line would overload by 42% of its design rating, as would the St. Cloud to Benton County line by 6%. Voltages at eighteen 115 kV buses would be below design with one as low as 81%.

Q: Describe how the proposed project will mitigate the St. Cloud area reliability issues you have identified.

A: The Twin Cities to Fargo 345 kV line will be tapped at a new Quarry substation on the west side of the city of St. Cloud, and a new 345/115 kV transformer will be installed to support the area. After this project is in service, the Granite City substation can be reconfigured to maintain the St. Regis load connection for the double line outage conditions I have described. The post contingency line loadings are improved from 133% with the St. Regis load not served, to less than 65% with the St. Regis load intact, and voltage is improved from 86.8% to 101% for these conditions, providing margin to accommodate load growth for this area.

Q: Are there any comparable alternative ways of resolving the reliability risks in the area other than the proposed Twin Cities to Fargo transmission line project?

A: No. We considered operation of local generation as well as upgrades to existing facilities in the area. None of these options resolved the loss of load risk projected for this area.

TWIN CITIES TO LA CROSSE 345 KV PROJECT

Q: Turning to the proposed Twin Cities to La Crosse 345 kV line project, please describe the Midwest ISO evaluation of the need for and effectiveness of this aspect of the CapX2020 project?

A: We reviewed the projected loadings and voltage conditions in the Rochester and La Crosse areas for the short and intermediate planning horizons. That analysis demonstrates that both of these areas can be expected to experience significant reliability problems unless new capacity is introduced into the area.

Q: Please describe these reliability issues.

A: The Rochester area is supplied by three 161 kV lines and supported by 181 MW of installed generation at the Silver Lake and Cascade Creek stations, and two small hydro units on the Zumbro river. In our study, even with all local generation on, we found numerous line overload conditions will result for various combinations of facility forced outages. For example, the Adams to Rochester 161 kV line will overload for six different combinations involving line and/or generator forced contingencies, with loading as high as 118% of rating for the loss of the Byron to Maple Leaf 161 kV line and the Alma to Wabaco 161 kV line. The same line will be overloaded at 116% of rating for the loss of the Byron to Maple Leaf 161 kV line during the longer duration outage of the Alma JPM generating unit. For the same generator off-line condition, the subsequent loss of a Byron 345/161 kV transformer would also overload this line. The prior outage of the Silver Lake #4 generating unit will cause the Adams to Rochester line to load to 95% of its rating in 2011 and would exceed its rating about two years later. The supply line from Alma may also experience overload conditions in the event that the other two supply line routes from Byron and Adams are out of service, even with all local generation in the area assumed available.

If the smaller peaking units (Silver Lk 1,2,3 and Cascade 1) are not available, a double contingency condition could result in loadings as high as 173% in the 2011 timeframe, and in addition the Adams to Rochester 161 kV line will be loaded to 97% of rating for the single contingency loss of either the Byron to Maple Leaf line, or the Byron 345/161 kV transformer.

Q: How does the proposed project resolve the reliability issues you have identified?

A: The project will install a new North Rochester 345 kV to 161 kV substation with a step down transformer between the 345 kV Prairie Island to Byron 345 kV line and the 161 kV. A 10.5 mile 161 kV line will be built between the new substation and the Northern Hills substation in Rochester. This new transformer and line will parallel the Byron transformer, and the Byron to Maple Leaf 161 kV line which is a critical outage for the area as I have described. When this line is out, the new parallel line will carry additional flow to Rochester to reduce loadings on otherwise overloaded existing 161 kV supply lines.

Q: What alternative solutions did the Midwest ISO consider to address the reliability issues you have identified in the Rochester area?

A: Since the reliability issues will begin to occur in the future even with all local generation available, there are no local generation dispatch options that will provide viable solutions into the future. Other than dropping load, which we estimate could require up to 55 MW[6] in order to maintain a secure system post contingency, we considered uprating of the existing 161 kV supply system. No alternative was found that would address both the Rochester area issues and the reliability issues in the La Crosse area as the proposed project will.

Q: Please describe the projected reliability conditions in the La Crosse area that the proposed project will address.

A: This area is supplied primarily by four 161 kV lines: Alma - Marshland – La Crosse; Alma – Tremval – La Crosse; Genoa – Coulee: and Genoa – La Crosse. There is 1144 MW of generation in and adjacent to the load area, with 610 MW at Alma to the north, 368 MW at Genoa to the south of Lacrosse, 26 MW of refuse burning units, and 140 MW of gas turbine peaking units at French Island in central La Crosse. Over the short term planning horizon, the Midwest ISO analysis found numerous reliability issues associated with serving this area with the existing system. Multiple single transmission line outage conditions will result in loadings above facility ratings, especially if occurring during the longer duration outage of a single area generating unit. Facility loading projections for the near term could be as high as 24% above rating.

Q: How does the proposed project resolve these issues?

A: The project will introduce a strong 345 V source into the area by terminating the 345 kV N. Rochester to N. Lacrosse line with a 345/161 kV transformer that will tie into this area centrally. With this new source available, the worst loading conditions will be relieved for many years into the future,

Q: What alternatives did you consider for resolving the reliability issues you have identified in the La Crosse area?

A: We considered a 161 kV rebuild option for the area. Because each of the four supply routes in the area are subject to overloading, this would require a near complete rebuild of the local area system at an estimated cost of more than $173 million. This expenditure would not provide the level of support that is provided by the proposed project nor the ability to accommodate future load growth in the area to a comparable degree. As an example, for the worst loading condition that I have described, the 124 % loading level on the Genoa – La Crosse line, this loading would be reduced after rebuilding to 86% of loading as compared to 48% with the proposed project. This means that loadings on these same upgraded lines will become problematic again in the near future long before they would with the proposed project in place. In addition, other lines around the area would reach their

[6] This is estimated to be more than 14% of the entire Rochester load.

limits even before these upgraded lines did, which would add to the cost of the alternative in this area.

Q: How would you summarize the effectiveness of both the Twin Cities to Fargo line, and the Twin Cities to La Crosse line in meeting expected local reliability needs?

A: These two 345 kV projects are especially effective in addressing future reliability needs in the Twin Cities and surrounding areas and will provide for sustained reliability for many years. The projects will provide for long term local reliability in both the northern and southern the Red River Valley areas, as well as in the Alexandria, St. Cloud, Rochester, and La Crosse areas. As such, the projects represent a prudent application of higher voltage supply solutions to address a variety of reliability needs in many different areas of the system simultaneously and to provide for those needs for the foreseeable future.

TWIN CITIES TO BROOKINGS COUNTY 345 KV PROJECT

Q: Has the Midwest ISO considered the needs and benefits of the Brookings to Twin Cities 345 kV project proposed by the Applicants?

A: Yes, we have.

Q: What, in your opinion, is the primary issue driving the need for this project?

A: The Twin Cities to Brookings County Project ("Brookings project") is essential to the delivery of renewable energy resources requesting interconnection to the transmission system in the vicinity of this project.

Q: Approximately how many generation interconnection requests are pending in the Midwest ISO interconnection queue at this time that will require the Brookings line to be in service in order for these resources to operate reliably?

A: There are nearly 50 generator interconnection requests along or near the counties where the Brookings County - Twin Cities 345 kV line is intended to be routed. This represents a total of approximately 5,600 MW of requests in the general area of project, with over 2700 MW specifically within the counties along the preliminary Brookings to Twin Cities project route.

Q: To what extent will the proposed Brookings to Twin Cities project provide necessary incremental capacity to support the delivery of renewable energy that is requesting to be interconnected in the vicinity of the project?

A: Studies by the Applicants have indicated that the project will provide firm incremental power transfer of about 700 MW, taking into account contingency conditions. Midwest ISO interconnection studies showed that 1300 MW of generation required the Brookings to Twin Cities project to resolve a key constraint before they can interconnect.

Q: Has MISO been able to confirm that there would be a material impact on the reliability of the system if these new generators are connected and the Brookings to Twin Cities line does not go into service?

A: Yes, we have.

Q: Please explain?

A: The Midwest ISO has identified 1300 MW of wind generation desiring to connect that requires the Brookings to Twin Cities line. This causes a constraint which comes about because of the potential loss of the 345kV Lakefield-Wilmarth line, which exists now and is parallel to the Brookings to Twin Cities route. Without the Brookings line, reliability of the existing system will not meet national standards. The Midwest ISO believes that all short-term solutions have been exhausted, and this facility is required for the proposed generation identified to be built in the area.

Q: Does the Midwest ISO support the design of the entire Brookings project as double circuit compatible?

A: Yes, we do. We agree with the Applicants that the relatively small premium to be incurred to enable a second circuit to be installed is prudent, especially in the area of the Brookings line that has the large volume of new generation under development.

Q: How does this project fit into the long-term plan for the area?

A: As I described earlier, this project is needed to reliably deliver new generation developments in the near term, as there are many more interconnection requests in queue today in the area of the line than the present transmission system can reliably accommodate. As such, in developing our long-range planning concepts, we have included the CapX projects as a part of the foundational plans upon which the longer term plans are being developed and analyzed. Simply stated, the Brookings County - Twin Cities 345 kV line is, in our opinion a necessary step in enabling the renewable energy objectives of the UMTDI and its member states. Additional facilities will be required to meet the total requirements. These additional longer-term facilities are being designed to work in concert with existing system and expansion plans in the area, including the proposed lines at issue in this docket.

Q: Will there be adequate outlets from the Twin Cities area to ensure that the additional resource interconnections enabled by the proposed projects is not bottled up in the area?

A: Yes. The La Crosse project will extend the high voltage system capacity to the east and is expected to be in service at or near the same service dates as the Fargo and Brookings projects. In addition, Regional Generation Outlet Studies in progress by the Midwest ISO will support multiple additional extensions of the 345 kV or higher transmission system in the upper Midwest to other parts of the Midwest ISO system. The sequencing of these additional extensions will be carefully coordinated with the CapX projects by the Midwest ISO in collaboration with our Transmission Owner members to ensure adequate system performance throughout this development.

Q: Are there other system needs that the new Brookings to Twin Cities line will address?

A: Yes. The line will also provide local reliability benefits to the area.

Q: How will these additional local reliability benefits be achieved?

A: In addition to transferring renewable energy from the wind resource-rich southwest Minnesota area to the 345 kV grid in the Minneapolis area, the project will support the underlying lower voltage transmission systems along the route by installing step-down transformers at Lyon County, Franklin (Cedar Mountain), and Lake Marion, and at a new Hazel Creek substation near Granite Falls. These step-down transformers will reduce loadings on 115 kV and 69 kV circuits extending into these areas from more distant supply sources by injecting a strong source of power at these step-down points along the route. Voltages on these systems will also be supported to provide for better service quality under contingent conditions involving the local transmission systems.

<u>ADDITIONAL BENEFITS OF THE PROPOSED PROJECTS</u>

Q: In your opinion, are there other benefits that you believe the four CapX2020 projects will provide?

A: Yes. The combined projects connect the Twin Cities area to adjacent areas of the transmission system either directly at or near to existing 345 kV networks and in geographically diverse directions to the northwest, southwest and southeast. This design will provide for a great deal of flexibility in enabling resources in North Dakota and Minnesota to be delivered to load centers in the Midwest ISO market and in providing access to both existing and future resources within the Midwest ISO market. This high capacity interconnectivity can be expected to have a lowering effect on average marginal energy prices in the upper Midwest part of the Midwest ISO market in the near term. In the long term, this interconnectivity will help to ensure adequate supplies will be available to market participants in the Twin Cities and surrounding areas, and will provide for more options in selection by those market participants of preferred sources of supply.

Q: Does this conclude your testimony?

A: Yes, it does.

AFFIDAVIT

I, Jeffrey R. Webb, Director of Expansion Planning, of Midwest Independent Transmission System Operator, Inc. verify, state, and affirm that I prepared or supervised the preparation of the testimony filed with this Affidavit, and that the testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Jeffrey R. Webb

STATE OF INDIANA)
COUNTY OF HAMILTON)

SUBSCRIBED AND SWORN TO before me by Jeffrey R. Webb on this 12th day of May, 2010.

Edith L. Bandy
Notary Public
My Commission Expires 04-29-2018

EDITH L. BANDY
Notary Public, State of Indiana
Marion County
Commission # 617849
My Commission Expires
April 29, 2018

CERTIFICATE OF SERVICE

Keith L. Beall certifies that on the 12th day of May, 2010, he served a true and correct copy of the attached Direct Testimony of Jeffrey R. Webb by e-mailing and where a mailing address has been provided by placing a copy in the United States mail with postage prepaid, addressed to the following individuals:

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