July 31, 2013

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: NERC Full Notice of Penalty Northern States Power (Xcel Energy), FERC Docket No. NP13-_-000

Dear Ms. Bose:

The North American Electric Reliability Corporation (NERC) hereby provides this Notice of Penalty[1] regarding Northern States Power (Xcel Energy) (Northern States Power), NERC Registry ID# NCR01020,[2] in accordance with the Federal Energy Regulatory Commission's (Commission or FERC) rules, regulations and orders, as well as NERC's Rules of Procedure including Appendix 4C (NERC Compliance Monitoring and Enforcement Program (CMEP)).[3]

Northern States Power Company, a Minnesota corporation (NSPM), and Northern States Power Company, a Wisconsin corporation (NSPW), are collectively referred to as Northern States Power.

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards* (Order No. 672), III FERC Stats. & Regs. ¶ 31,204 (2006); *Notice of New Docket Prefix "NP" for Notices of Penalty Filed by the North American Electric Reliability Corporation*, Docket No. RM05-30-000 (February 7, 2008). *See also* 18 C.F.R. Part 39 (2011). *Mandatory Reliability Standards for the Bulk-Power System*, FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *reh'g denied*, 120 FERC ¶ 61,053 (2007) (Order No. 693-A). *See* 18 C.F.R § 39.7(c)(2).

[2] Midwest Reliability Organization (MRO) confirmed that Northern States Power was included on the NERC Compliance Registry as a Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Generator Operator (GOP), Load Serving Entity (LSE), Purchasing-Selling Entity (PSE), Resource Planner (RP), Transmission Owner (TO), Transmission Operator (TOP), Transmission Planner (TP) and Transmission Service Provider (TSP) on May 30, 2007. As a BA and TOP, Northern States Power is subject to the requirements of NERC Reliability Standard COM-002-2. As a DP, GO, and TO, Northern States Power is subject to the requirements of NERC Reliability Standard PRC-004-1. As a DP and TO, Northern States Power is subject to the requirements of NERC Reliability Standard PRC-005-1. As a BA, RC and TOP, Northern States Power is subject to the requirements of NERC Reliability Standard EOP-008-0. On January 6, 2009, Northern States Power was registered as a Coordinated Functional Registration (formerly Type 2) Joint Registration Organization (JRO00001) for the BA function.

[3] *See* 18 C.F.R § 39.7(c)(2).

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NSPM and NSPW operate a single integrated generation and transmission system with ownership of assets bifurcated at the Minnesota/Wisconsin border. Northern States Power serves customers in portions of Minnesota, North Dakota, eastern South Dakota, western Wisconsin, and the upper peninsula of Michigan. Northern States Power has approximately 1.6 million electric customers and is a summer peaking system. Northern States Power operates at the following transmission voltages: 34.5 kV, 69 kV, 88 kV, 115 kV, 161 kV, 230 kV, 345 kV, and 500 kV. Northern States Power owns an estimated total of 7,216 miles of transmission lines. There are a total of 143 interconnected points on the systems operated within the Northern States Power System at 69 kV and above.

This Notice of Penalty is being filed with the Commission because Midwest Reliability Organization (MRO) and Northern States Power have entered into a Settlement Agreement to resolve all outstanding issues arising from MRO's determination and findings of the violations[4] of COM-002-2 R2, PRC-004-1 R1, EOP-008-0 R1.5, and PRC-005-1 R2.1. According to the Settlement Agreement, Northern States Power neither admits nor denies the violations, but has agreed to the assessed penalty of two hundred and fifty thousand dollars ($250,000), in addition to other remedies and actions to mitigate the instant violations and facilitate future compliance under the terms and conditions of the Settlement Agreement. Accordingly, the violations identified as NERC Violation Tracking Identification Numbers MRO201100263, MRO201100268, MRO201100332, and MRO201100333 are being filed in accordance with the NERC Rules of Procedure and the CMEP.

Statement of Findings Underlying the Violations

This Notice of Penalty incorporates the findings and justifications set forth in the Settlement Agreement executed on April 12, 2013, by and between MRO and Northern States Power, which is included as Attachment a. The details of the findings and basis for the penalty are set forth in the Settlement Agreement and herein. This Notice of Penalty filing contains the basis for approval of the Settlement Agreement by the NERC Board of Trustees Compliance Committee (NERC BOTCC). In accordance with Section 39.7 of the Commission's regulations, 18 C.F.R. § 39.7 (2013), NERC provides the following summary table identifying each violation of a Reliability Standard resolved by the Settlement Agreement, as discussed in greater detail below.

[4] For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, alleged or confirmed violation.

Region	Registered Entity	NOC ID	NERC Violation ID	Reliability Std.	Req. (R)	VRF	Total Penalty
Midwest Reliability Organization	Northern States Power (Xcel Energy)	NOC-1886	MRO201100263	COM-002-2	R2	Medium	$250,000
			MRO201100268	PRC-004-1	R1	High	
			MRO201100332	EOP-008-0	R1.5	Medium	
			MRO201100333	PRC-005-1	R2.1	High	

COM-002-2 R2

The purpose statement of Reliability Standard COM-002-2 provides: "To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective."

COM-002-2 R2 provides: "Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings."

COM-002-2 R2 has a "Medium" Violation Risk Factor (VRF) and a "Severe" Violation Severity Level (VSL).[5] The subject violation applies to Northern States Power's Balancing Authority (BA) and Transmission Operator (TOP) functions. On September 18, 2007, the MRO region experienced a category four event initiated by a transmission system conductor failure on the Prairie Island-Byron 345 kV line.[6] The category four event included a cascade of multiple lines that form the Minnesota-Wisconsin Stability Interface. The loss of these lines was followed by over-frequency generator tripping and under-frequency load shedding, which resulted in the formation of system islands. North

[5] COM-002-2 R2 did not have an assigned VSL on September 18, 2007. Additionally, there were no "Levels of Noncompliance" applicable to Requirement 2 on September 18, 2007. Subsequently, VSL assignments for COM-002-2 R2 were approved. The "Severe" VSL applies where the responsible entity failed to provide a directive in a clear, concise, and definitive manner when required.

[6] NERC classified this event as a "category four" event due to the interconnected system separation and islanding of 1,000 MW of load or generation. Category four events require a detailed event analysis. While NERC currently classifies a "category 4" event as unintended system separation that results in an island of more than 10,000 MW, at the time of the September 18, 2007 event, NERC defined a "category four" event as an event that results in any or combination of the following actions: a. the occurrence of an interconnected system separation or islanding; and b. the loss of load (1,000 to 9,999 MW).

Dakota, Minnesota, Manitoba, part of South Dakota, and Saskatchewan separated from the Eastern Interconnection. Saskatchewan then separated from Manitoba and North Dakota.

Various MRO registered entities in the first island were reconnected to the Eastern Interconnection in less than 10 minutes through automatic reclosing of a number of open transmission lines between that island and the Eastern Interconnection. The second island was reconnected to the Eastern Interconnection in 58 minutes. The event resulted in load loss of approximately 9 MW in the United States.[7]

On March 5, 2008, NERC conducted a Compliance Investigation (CI) regarding the Category 4 event. The CI team determined that when issuing directives to the generator operators, the Northern States Power transmission operator failed to provide directives in a clear, concise manner and did not require the generator operator to repeat back the directives. MRO reviewed the voice recordings and concurred with the CI team.

MRO identified four telephonic communications that were not clear and concise and/or did not fully utilize three-part communication. The first communication occurred during the event when the Northern States Power transmission operator directed, “We better get 3 Wheatons on there.” While it is clear that the reference is to generation at the Northern States Power Wheaton Generating Station which has six units, it is not clear which units or what amount of generation is needed. Additionally, the response did not include a repeat of the directive or request for clarity; instead the recipient generator operator stated, “Yeah, we’re gonna go right now.”

The second communication identified by MRO also occurred during the event when the transmission operator stated, “Take Sherco 2 off control and run units 1 and 2 at 350.” The recipient generator operator stated, “You want to run them at 350 a piece?” The issuer transmission operator responded “Yes.” While this repeated part of the directive, it did not include the full directive, and the acknowledgement did not clarify all actions included in the directive, i.e., there was no reference to taking Sherco 2 “off control.”

[7] The September 18, 2007 event resulted in load loss of approximately 787 MW, with only 9 MW of the load loss occurring in the United States. The majority of the load loss, approximately 769 MW, occurred in the service area of a neighboring entity that is not subject to FERC jurisdiction. According to the Event Analysis Report, “[t]he causal factor for the separation of the [Canadian entity’s] system from the first island was the sensitive, uncoordinated settings of over-frequency protection on a range of thermal generators. Premature tripping of these units resulted in the separation of the [Canadian entity’s] system from the first island, and in significant load shedding in the [Canadian entity’s] system.” An additional 9 MW of load loss occurred in the service area of another neighboring entity that is not subject to FERC jurisdiction.

The third communication also occurred during the event, when the transmission operator stated, "Have 3 drop about 100 too, if they can." The recipient generator operator responded, "Ok. More than what they just fell off frequency?" The issuer transmission operator stated, "Yes, it's all frequency." In both the second and third instances, the directive may have been clear and concise, but three-part communication was not utilized during an emergency situation.

The final communication occurred during restoration when the transmission operator directed, "Put Shercos back on control, or, if you want to, move them up a little bit and then put them on." The recipient generator operator response was "Ok." Similar to the first communication, it is clear that the reference is to generators at the Sherco Generating Station, which has three units with a combined capacity of 2,400 MW. It is not clear, however, which units or what amount of generation are being requested. Again, the response did not include a repeat of the directive or request for clarity.

MRO determined that Northern States Power had a violation of COM-002-2 R2 because it failed to provide directives in a clear, concise, and definitive manner and failed to require the recipient GOP to repeat back the directive as required by COM-002-2 R2.

MRO determined the duration of the violation to be one day, September 18, 2007, when the recordings from the event indicate that clear, concise, and direct communication with three-part communication was not utilized.

MRO determined that this violation posed a moderate risk to the reliability of the bulk power system (BPS), but did not pose a serious or substantial risk. Specifically, it is critically important to BPS reliability that directives be issued in a clear, concise, and definitive manner and that three-part communications be utilized during an emergency situation. When this is not the case, the potential for misunderstandings, misdirection, and miscommunication is high and can result in, contribute to, or exacerbate a system disturbance.

The risk to the BPS was mitigated by the following factors. All four of the communications at issue involved personnel who had access to the same tools (i.e., the Northern States Power energy management system (EMS)) and these same personnel were able to see the same information regarding system status. The personnel were properly equipped to respond to the directives because of the shared tools with the same information and familiarity with the system. The first island was reconnected in just over eight minutes and the Event Analysis Report commended the coordination and communication efforts of those involved, including Northern States Power. The operating personnel were familiar with proper use of three-part communication and clear, concise and definitive directives. If the personnel involved in the event were different, the lack of clear, concise and definitive communications and the failure to use three-part communication during an emergency situation could have resulted in a much greater risk to the reliability of the BPS.

In this instance, although MRO concluded that certain directives were not clear, concise, and definitive and that three-part communication was not fully utilized, the directives given to the applicable personnel were followed and actions taken as intended by the issuer of the directives. Because the directives were correctly implemented, the directives met the purpose stated in COM-002-2 of ensuring effective communications by operating personnel. Furthermore, there is no evidence that the four communications contributed to or exacerbated the event, but were steps taken to contain the event and ultimately restore the system.

PRC-004-1 R1

The purpose statement of Reliability Standard PRC-004-1 provides: "Ensure all transmission and generation Protection System[8] Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated." [Footnote added.]

PRC-004-1 R1 provides: "The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's[9] procedures developed for Reliability Standard PRC-003 Requirement 1." [Footnote added.]

PRC-004-1 R1 has a "High" VRF and a "Moderate" VSL. The subject violation applies to Northern States Power's Distribution Provider (DP) and Transmission Owner (TO) functions.

The CI Team identified a violation of PRC-004-1 R1[10] because Northern States Power did not complete the Corrective Action Plan within the intended timeframe for the misoperation of the Coon Creek - Terminal 345 kV line Protection System which occurred on June 22, 2007, four days after the date of mandatory compliance with NERC Reliability Standards.

[8] *The NERC Glossary of Terms Used in Reliability Standards* defines Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry."
[9] Consistent with applicable FERC precedent, the term "Regional Reliability Organization" in this context refers to MRO.
[10] The CI team identified three findings related to PRC-004-1 R1. MRO consolidated these three findings into one violation and validated one instance of noncompliance with PRC-004-1, R1 related to the Coon Creek - Terminal misoperation addressed herein.

Upon review of the facts, circumstances, and evidence provided by NERC, MRO concurred that Northern States Power did not complete the Corrective Action Plan for the misoperation of the Coon Creek - Terminal 345 kV line Protection System, which occurred on June 22, 2007, within the timeframe intended. After the misoperation, Northern States Power conducted analysis and developed a Corrective Action Plan with a proposed completion date of August 10, 2007. According to the statement of Northern States Power's principal specialty engineer, testing for certain relays associated with the misoperation had not been completed.

As part of the investigation, the CI team conducted a Spot Check from February 24, 2009 through February 26, 2009. In response to a request during the Spot Check, Northern States Power concluded that it could not affirmatively represent to NERC that the required work had been performed. Northern States Power had developed a Corrective Action Plan for the June 22, 2007 Coon Creek - Terminal 345 kV line misoperation that included a list of maintenance activities intended to prevent recurrence of the misoperation. These maintenance activities were specified in a work request that triggered issuance of five work orders. Only two of these five work orders were completed as scheduled. These two work orders related to the line relay that misoperated and the associated telecommunication. Northern States Power was unable to provide documentation to establish that the remaining three work orders were completed within the timeframe scheduled by Northern States Power. Upon discovery, Northern States Power issued a new work request and associated work orders, and the work was completed on March 20, 2009.

MRO determined that Northern States Power had a violation of PRC-004-1 R1 because Northern State Power failed to complete the Corrective Action Plan for the misoperation of the Coon Creek - Terminal 345 kV line protection system within the timeframe identified in the Corrective Action Plan.

MRO determined the duration of the violation to be from August 10, 2007, when the Corrective Action Plan was scheduled to be completed, through March 20, 2009, when the Corrective Action Plan was completed.

MRO determined that this violation posed a moderate risk to the reliability of the BPS, but did not pose a serious or substantial risk. The improper closing of the maintenance activities without a system to verify proper completion of the Corrective Action Plan posed a risk to reliability of the BPS. In addition, the transmission line is located in the Twin Cities metropolitan area, is associated with a voltage level of 345 kV, and is interconnected with three surrounding 345 kV transmission lines. Furthermore, the failure to complete the Corrective Action Plan as scheduled increased the risk of a recurrence that could have affected higher voltage facilities serving a major metropolitan area. Although Northern States Power developed a Corrective Action Plan for the June 22, 2007 Coon Creek - Terminal 345 kV line misoperation that included a list of maintenance activities intended to prevent recurrence of the misoperation, the Corrective Action Plan was not completed within the timeframe intended by Northern States Power. While the relay did not misoperate between the time that the maintenance activities were initially identified and the time that the maintenance activities were actually completed, the Northern States Power Corrective Action Plan was prematurely closed. Although MRO determined that this misoperation was not related to the event that occurred on September 18, 2007, had it not been for the Spot Check conducted as a result of the CI, it is not known whether or when Northern States Power would have determined that it had not completed the Corrective Action Plan as scheduled.

The risk to the BPS was mitigated by the fact that although only two out of five work orders were timely completed, the two that were timely completely addressed the greatest risk of recurrence, as they related to the line relay that misoperated and the associated telecommunications.

<u>EOP-008-0 R1.5</u>

The purpose statement of Reliability Standard EOP-008-0 provides: "Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable."

EOP-008-0 R1 provides in pertinent part:

> R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:
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> ***
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> > R1.5. The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.

EOP-008-0 R1.5 has a "Medium" VRF and a "Severe" VSL. The subject violation applies to Northern States Power's BA and TOP functions.

During a regularly scheduled Compliance Audit conducted between February 14, 2011 and February 18, 2011, MRO determined that Northern States Power failed to include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of its plan for loss of control center functionality. As a TOP, Northern States Power maintains and operates two control centers. The main control center is located in Minneapolis, Minnesota and provides transmission operations for portions of Minnesota, South Dakota, and North Dakota. The second control center is located in Eau Claire, Wisconsin and provides transmission operations for the Wisconsin portion of the Northern States Power system.

MRO determined that Northern States Power had developed and tested its plans for loss of control center functionality for the Minneapolis Control Center. Northern States Power had also developed plans for loss of control center functionality at the Eau Claire Control Center but had failed to complete the annual testing of the plans. [redacted] MRO determined that Northern States Power had not tested the portion of the plan that included the system operator assuring communication ability via emergency cell phone and driving [redacted] to the [redacted] secondary control center. On February 23, 2011, within one week of the Compliance Audit, Northern States Power successfully tested and documented completion of the Eau Claire Control Center plans for loss of control center functionality.

MRO determined that Northern States Power had a violation of EOP-008-0 R1.5 because it failed to include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of its plan for loss of control center functionality.

MRO determined the duration of the violation to be from January 1, 2008, when testing of the plans for loss of control center function for the Eau Claire Control Center should have been completed, through February 23, 2011, when the Eau Claire Control Center plans for loss of control center function were fully tested.

MRO determined that this violation posed a minimal and not serious or substantial risk to the reliability of the BPS. Although Northern States Power failed to completely test its plans for loss of control center functionality at its Eau Claire Control Center, the majority of the plan test was completed, and complete plans had been developed. Both of the Northern States Power Control Centers operate from the primary EMS in the Minneapolis Control Center. Therefore, in the event of evacuation of the Eau Claire Control Center, the operation of the primary EMS would be unaffected. The Minneapolis Control Center has a terminal configured with the Eau Claire Control Center authorities. Each weekday morning, transmission operators in the Minneapolis Control Center log into the terminal and verify that it is operational. MRO determined that the failure to test the final part of the plans for loss of control center functionality (i.e., driving five miles and making a phone call) had minimal impact to the reliability to the BPS.

PRC-005-1 R2.1

The purpose statement of Reliability Standard PRC-005-1 provides: "To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested."

PRC-005-1 R2 provides in pertinent part:

> R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:
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>> R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

PRC-005-1 R2.1 has a "High" VRF and a "Lower" VSL. The subject violation applies to Northern States Power's DP, GO, and TO functions.

During the pre-audit documentation review process for a regularly scheduled Compliance Audit conducted between February 14, 2011 and February 18, 2011, MRO requested relay records associated with a list of randomly selected stations. After receiving the request, Northern States Power notified MRO that it was not able to provide evidence that certain relays had been tested within the established interval.

Northern States Power reported that the 1N2 and 1N6 relay schemes at the Monticello Nuclear Generating Plant (MNGP) were not tested within the respective established intervals. The 1N2 relay scheme was due to be tested by October 2006 and was deferred in accordance with Northern States Power's Protection System maintenance and testing program until October 2008. However, the 1N2 relay scheme was not tested until November 5, 2010. The results of the November 5, 2010 test were satisfactory and indicated that the relay scheme was capable of performing its protective function during the period the testing exceeded the established interval. The 1N6 relay scheme was required to be tested by March 2010, but Northern States Power could not provide evidence that the test was conducted or properly deferred. The 1N6 relay scheme was tested on February 13, 2011 and was found in calibration and functional.

Northern States Power further reported that it had initiated an internal investigation into the cause of not performing the testing as scheduled and an extent of conditions review. Northern States Power determined the cause in both instances to be human error in not following established procedures. With regard to the 1N2 relay scheme, the test was properly deferred until October 2008 but was erroneously marked as complete in another work order. With regard to the 1N6 relay scheme, the test was scheduled to be conducted during the spring 2009 scheduled outage. However, the test was not deferred, and the activity was not timely identified as incomplete or past due because outage-coded maintenance and testing was tracked manually rather than through an automated or computerized method.

As part of the Mitigation Plan process, Northern States Power performed a comprehensive review of the Protection System maintenance and testing records at its two nuclear facilities, MNGP and Prairie Island Nuclear Generating Plant (PINGP). During this review, Northern States Power identified additional protection system components that had not been tested and maintained within the defined intervals. Northern States Power failed to perform required functional and calibration testing associated with: 5 of its 234 protection relays; 9 of its 234 DC control circuits; and 6 of its 73 current and voltage sensing devices at PINGP. All of these components exceeded the six-year maintenance and testing interval by one year and eight months. Northern States Power did not identify any issue when these components were tested.

Northern States Power also failed to perform required functional and calibration testing associated with 8 of its 67 protection relays subject to PRC-005-1 R2 and 8 of its 75 DC control circuits at MNGP. Maintenance and testing of these Protection System components exceeded the four-year interval by one year for half of the protective relays and DC control circuits and the other half of the identified components exceeded the four-year interval by five years. Northern States Power did not identify any issue when these components were tested.

MRO determined that Northern States Power had a violation of PRC-005-1 R2.1 because it failed to perform Protection System device testing within defined intervals.

MRO determined the duration of the violation to be from November 1, 2008, when the 1N2 relay scheme exceeded the October 2008 scheduled testing date, through April 30, 2012, when all maintenance and testing was completed.

MRO determined that this violation posed a moderate risk to the reliability of the BPS but did not pose a serious or substantial risk. For a two-year period, Protection System components at both nuclear generating plants were not maintained and tested according to the defined intervals. The combined generation capability of these two generation plants is approximately 1700 MW. The plants generate about 30 percent of the electricity used by Northern States Power's customers in the upper Midwest. PINGP is located about 40 miles southeast of Minneapolis-Saint Paul. MNGP is located approximately 40 miles northwest of Minneapolis-Saint Paul. The risk to the BPS was mitigated by the fact that there are both primary and back up Protection Systems, in the form of solid state relays, safeguarding the generators. In addition, no issues were identified upon completion of the maintenance and testing.

<u>Regional Entity's Basis for Penalty</u>

According to the Settlement Agreement, MRO has assessed a penalty of two hundred fifty thousand dollars ($250,000) for the referenced violations. In reaching this determination, MRO considered the following factors:

1. Northern States Power's compliance history was considered an aggravating factor;[redacted]
2. Northern States Power was cooperative throughout the compliance enforcement process and had internal controls in place prior to completing the Mitigation Plans;[12]

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[11] [redacted]

A Notice of Confirmed Violation covering violations of CIP-001-1 R2 for Northern States Power was filed with FERC under NP08-16-000 on June 4, 2008. On July 3, 2008, FERC issued an order stating it would not engage in further review of the Notice of Penalty.

A Notice of Confirmed Violation covering violations of VAR-001-1 R3 and R4 for Northern States Power was filed with FERC under NP09-19-000 on May 1, 2009. On May 29, 2009, FERC issued an order stating it would not engage in further review of the Notice of Penalty.

A Notice of Confirmed Violation covering violations of EOP-001-0 R5 for Northern States Power was filed with FERC under NP09-18-000 on May 1, 2009. On May 29, 2009, FERC issued an order stating it would not engage in further review of the Notice of Penalty.

MRO determined that Northern States Power's previous violations of CIP-001-1 R2, VAR-001-1 R3 and R4, and EOP-001-0 R5 did not constitute prior violations and were not considered an aggravating factor in the penalty determination; they involved Standards and Requirements that are not the same as the instant violations. Moreover, there was nothing in the record to suggest that broader corporate issues were implicated.

3. certain aspects of Northern States Power's internal compliance program;[13]

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[12] MRO considered Northern States Power's cooperation as a mitigating factor in the penalty determination. While Northern States Power met expectations and fully cooperated in the review and assessment of the violations resulting from the CI, MRO considered Northern States Power's cooperation with regard to the Compliance Audit findings to be exemplary.

Northern States Power reported that the following internal controls were in place prior to actions taken under the Mitigation Plan:

1) each Standard and Requirement is assigned an organizational owner at each site;
2) the compliance roadmap is updated and evidence refreshed on an annual basis;
3) in preparation for annual self-certification, a review of compliance for the year is conducted, which includes spot checks of testing records., All data is then provided to the vice president of nuclear, who then reviews and attests compliance to the authorized entity officer (vice president of transmission or chief information officer); and
4) surveillances are flagged by computer software to be performed with an early due date, a due date, late due date, and a compliance credit date.

[13] Northern States Power, as an operating company within the Xcel Energy Inc. holding company (Xcel Energy), has a documented FERC/NERC compliance program, as partially evidenced by its program charter, which was approved July 2, 2009. Xcel Energy's compliance program has a two-fold mission: 1) through monitoring and oversight, provide reasonable assurance that Xcel Energy and its subsidiaries are compliant with enforceable requirements adopted by FERC and NERC along with the Regional Entities; and 2) through coordination with internal stakeholders, promote the policy objectives of Xcel Energy Services, Inc. and the Xcel Energy Operating Companies, as they relate to development and application of enforceable requirements of FERC, NERC, and the Regional Entities

Xcel Energy's compliance programs fall under the general oversight of the corporate compliance and business conduct program (CCBC). The purpose of the CCBC is to promote a culture across Xcel Energy and its subsidiaries that encourages ethical conduct and a commitment to compliance with the law. Xcel Energy's vice-president and corporate secretary is also the corporation's chief compliance officer and has overall responsibility for the CCBC. On a periodic basis, the CCBC will review the effectiveness of each of the company's compliance programs, including the FERC/NERC compliance program.

Day-to-day management of the FERC/NERC compliance program falls under the responsibility of the director, compliance monitoring and policy with oversight from the FERC compliance officer. Xcel Energy's compliance programs fall under the general oversight of the CCBC.

The FERC compliance officer is responsible for: 1) fostering a culture of compliance among affected business units; 2) monitoring compliance through internal audits, spot checks, investigations, or other reviews; 3) coordinating activities associated with implementation of new or revised requirements; 4) working with affected business units as necessary to ensure that appropriate corrective measures are implemented; and 5) facilitating training as needed to support the company's FERC and NERC compliance programs.

Oversight of the FERC/NERC compliance program is provided by an executive-level steering committee. The steering committee sets policy for the FERC/NERC compliance program. The responsibilities of the steering committee are to assist the FERC compliance officer with: 1) monitoring and overseeing the FERC/NERC compliance program on behalf of the operations council; 2) setting policy direction for the enterprise-level FERC/NERC compliance program; 3) ensuring

4. the violations of COM-002-2 R2, PRC-004-1 R1, and PRC-005-1 R2.1 posed a moderate risk but not serious or substantial risk to the reliability of the BPS. The violation of EOP-008-0 R1.5 posed a minimal and not serious or substantial risk to the reliability of the BPS.
5. there was no evidence of any attempt by Northern States Power to conceal the violations;
6. there was no evidence that Northern States Power's violations were intentional; and
7. there were no other mitigating or aggravating factors or extenuating circumstances that would affect the assessed penalty.

After consideration of the above factors, MRO determined that, in this instance, the penalty amount of two hundred and fifty thousand dollars ($250,000) is appropriate and bears a reasonable relation to the seriousness and duration of the violations.

Status of Mitigation Plans[14]

COM-002-1 R2

Northern States Power's Mitigation Plan to address its violation of COM-002-1 R2 was submitted to MRO on April 26, 2012 stating it had been completed on June 18, 2010. The Mitigation Plan was accepted by MRO on April 26, 2012 and approved by NERC on January 10, 2013. The Mitigation Plan for this violation is designated as MROMIT007207 and was submitted as non-public information to FERC on January 10, 2013 in accordance with FERC orders.

Northern States Power's Mitigation Plan required Northern States Power to:

1. develop a control center communications procedure;
2. develop training for the control center communications procedure; and
3. implement training for the control center communications procedure.

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independence in the evaluation and review of compliance matters under the direction of the enterprise-level FERC/NERC compliance program; 4) resolving issues that may arise between the FERC/NERC compliance program and functional business units; and 5) ensuring adequate staffing and resources of the FERC/NERC compliance program to evaluate and monitor compliance at the functional business unit level.

The steering committee meets with FERC/NERC compliance program staff on a regular basis and as needed to address high-priority concerns. In addition, the FERC/NERC compliance program has access to the chief executive officer (CEO) and board via the FERC compliance officer, who reports directly to the CEO.

[14] *See* 18 C.F.R § 39.7(d)(7).

Northern States Power certified on January 9, 2013 that the above Mitigation Plan requirements were completed on June 18, 2010. As evidence of completion of its Mitigation Plan, Northern States Power submitted the following:

1. *NSP-PRO-A-002 NSP Control Center Communications.pdf*;
2. *CommunicationsProtocol Xcel Energy Confidential, pdf*;
3. *Com Training List – NSP Operators.pdf*;
4. *Com Training List – Xcel Energy.pdf*;
5. T053104a12.wav, a directive regarding Wheaton units
6. T053259a.wav, a directive regarding Sherco units
7. T053516a.wav, a directive regarding “3 drop 100 to”
8. T054019a.wav, a directive regarding Sherco during restoration; and
9. *COM-002-2 MP NSP Authorization.pdf*.

On April 26, 2012, after reviewing Northern States Power’s submitted evidence, MRO verified that Northern States Power’s Mitigation Plan was completed on June 18, 2010.

<u>PRC-004-1 R1</u>
Northern States Power’s Mitigation Plan to address its violation of PRC-004-1 R1 was submitted to MRO on May 4, 2012 with a proposed completion date of August 1, 2010. The Mitigation Plan was accepted by MRO on May 7, 2012 and approved by NERC on May 30, 2012. The Mitigation Plan for this violation is designated as MROMIT007288 and was submitted as non-public information to FERC on June 1, 2012 in accordance with FERC orders.

Northern States Power’s Mitigation Plan required Northern States Power to:

1. complete the corrective action plan identified for the misoperation of the Coon Creek-Terminal line;
2. reorganize to create a new system protection engineering area responsible for management of the misoperation analysis and corrective action process; and
3. review and revise the Xcel Energy misoperation process/procedure.

Northern States Power certified on May 8, 2012 that the above Mitigation Plan requirements were completed on July 1, 2010. As evidence of completion of its Mitigation Plan, Northern States Power submitted the following:

1. *XEL-PRO-TransmProtSysMisOpProcedure.pdf*;
2. *XEL-PRO-TransmProtSystMisOpInvestProcessMap.pdf*;
3. *XES-17 Work Orders for Coon Creek-Terminal.pdf*; and
4. *System Protection Engineering Organization Chart*, dated April 5, 2012.

On May 10, 2012, after reviewing Northern States Power's submitted evidence, MRO verified that Northern States Power's Mitigation Plan was completed on July 1, 2010.

EOP-008-0 R1.5

Northern States Power's Mitigation Plan to address its violation of EOP-008-0 R1 was submitted to MRO on December 19, 2011 with a proposed completion date of April 30, 2012. The Mitigation Plan was accepted by MRO on December 22, 2011 and approved by NERC on January 22, 2012. The Mitigation Plan for this violation is designated as MROMIT006515 and was submitted as non-public information to FERC on January 26, 2012 in accordance with FERC orders.

Northern States Power's Mitigation Plan required Northern States Power to:

1. create an overall test plan that describes the procedures and responsibilities for conducting periodic tests, at least annually, for loss of a primary control center;
2. conduct a post-test review of the loss of control center exercise and document and incorporate any improvements or changes that were identified; and
3. perform a comprehensive review all of the requirements of EOP-008 to identify any additional needed actions and completed actions.

Northern States Power certified on April 12, 2012 that the above Mitigation Plan requirements were completed on April 12, 2012. As evidence of completion of its Mitigation Plan, Northern States Power submitted the following:

1. the 2010 plan subject to EOP-008 R 1.5 for the Eau Claire Control Center;
2. evidence that Eau Claire Control Center TOPs received training regarding EOP-008-0 R1 in 2008, 2009 and 2010; and

3. a summary regarding testing of the Eau Claire Control Center loss of control center function plan.

On April 13, 2012, after reviewing Northern States Power's submitted evidence, MRO verified that Northern States Power's Mitigation Plan was completed on April 12, 2012.

PRC-005-1 R2.1

Northern States Power's Mitigation Plan to address its violation of PRC-005-1 R2.1 was submitted to MRO on October 20, 2011 with a proposed completion date of April 30, 2012. The Mitigation Plan was accepted by MRO on October 20, 2011 and approved by NERC on January 22, 2012. The Mitigation Plan for this violation is designated as MROMIT005992 and was submitted as non-public information to FERC on January 26, 2012 in accordance with FERC orders.

Northern States Power's Mitigation Plan required Northern States Power to:

1. test the 1N6 relay scheme on February 13, 2011 to determine if it is in calibration and functional;
2. verify that the 1N2 relay scheme was tested on November 5, 2010 per PRC-005-1;
3. verify that MNGP PRC-005 related tests have been performed in accordance with the established intervals;
4. verify that the PINGP Units 1 and 2 PRC-005-related tests have been performed in accordance with the established intervals;
5. identify and track all MNGP and PINGP PRC-005 devices due to be tested prior to January 1, 2012 to ensure timely completion of scheduled activities during mitigation action plan period;
6. perform an additional follow-up review of nuclear site protective relay systems and validate the identified scope of components to be tracked as PRC-005-related and make any necessary adjustments;
7. verify, if any devices are added to the PRC-005 program for MNPG and PINGP, that all have been tested within the established interval and that testing is current;
8. complete an investigation to determine the cause of the missed tests and establish corrective actions;
9. develop and implement an additional code to flag PRC-005-related Protection Systems in the equipment database. This flag will allow these devices to be prioritized and queried for tracking/reporting purposes;

10. revise applicable site-specific and fleet level procedures to ensure PRC-005-1 related activities are addressed. These changes will include the following enhancements:
    a. the creation of a document that clearly ties all pieces of the existing Protection System maintenance and testing program together;
    b. require an additional level of review for the testing of PRC-005 components;
    c. increase the priority level of PRC-005-related testing and maintenance; and
    d. increase the rigor of review and approval;
11. issue a formal communication to the impacted maintenance, engineering, and scheduling personnel to increase awareness of PRC-005-1 testing requirements;
12. disseminate to all electrical maintenance and engineering personnel an information package that provides additional guidance on mandatory NERC compliance;
13. perform a training analysis to assess the need for additional electrical maintenance and engineering training on NERC compliance;
14. develop and implement, if additional training need is identified, a fleet lesson plan for NERC Standards applicable to electrical maintenance and engineering; and
15. perform, for all relay schemes to be tested prior to March 31, 2012, independent checks to ensure testing is complete prior to the required due dates.

Northern States Power certified on August 10, 2012 that the above Mitigation Plan requirements were completed on April 30, 2012. As evidence of completion of its Mitigation Plan, Northern States Power submitted the following:

1. *8050-03 (PE 002G-TC) 2011.pdf*, Prairie Island relay test report;
2. *FP-MA-PRC-051.pdf*, Revised PRC-005 related program documentation;
3. *FP-PE-PM-01-20101201.pdf*, Preventive Maintenance Program;
4. *FP-WM-OVW-01-20100728.pdf*, Work Management Process Overview;
5. *MNGP EWI-11 01 06.pdf*, Battery Monitoring and Maintenance Program;
6. Summary of mitigation plan completion and internal controls;
7. *MNGP PRC-005 Activities Jun 2011 to Mar 2012.xls*, Monticello Nuclear Plant;
8. *PINGP PRC-005 Activities Jun 2011 to Mar 2012.xls*, Prairie Island Nuclear Plan; t

9. Milestone 14 Action Completion Email, evidencing training completion;
10. Milestone 15 NERC Completions, personnel training completion records;
11. *Milestone 15 NERC PRC-005 PPT*, training content;
12. *Milestone 15 PRC-005 LMS Catalog*;
13. *Nuclear PRC-005 Summary*, spreadsheet of all PRC-005 program devices and the most recent two test dates for both nuclear plants;
14. *PINGP H37.pdf*, Battery Monitoring and Maintenance Program;
15. *PRC-005 Communication.pdf*; and
16. PRC-005 R2 Mitigation Plan Training.

On August 10, 2012, after reviewing Northern States Power's submitted evidence, MRO verified that Northern States Power's Mitigation Plan was completed on April 30, 2012.

Statement Describing the Assessed Penalty, Sanction or Enforcement Action Imposed[15]

Basis for Determination

Taking into consideration the Commission's direction in Order No. 693, the NERC Sanction Guidelines and the Commission's July 3, 2008, October 26, 2009 and August 27, 2010 Guidance Orders,[16] the NERC BOTCC reviewed the Settlement Agreement and supporting documentation on June 11, 2013. The NERC BOTCC approved the Settlement Agreement, including MRO's assessment of a two hundred and fifty thousand dollar ($250,000) financial penalty against Northern States Power and other actions to facilitate future compliance required under the terms and conditions of the Settlement Agreement. In approving the Settlement Agreement, the NERC BOTCC reviewed the applicable requirements of the Commission-approved Reliability Standards and the underlying facts and circumstances of the violations at issue.

In reaching this determination, the NERC BOTCC considered the following factors:

[15] *See* 18 C.F.R. § 39.7(d)(4).
[16] *North American Electric Reliability Corporation*, "Guidance Order on Reliability Notices of Penalty," 124 FERC ¶ 61,015 (2008); *North American Electric Reliability Corporation*, "Further Guidance Order on Reliability Notices of Penalty," 129 FERC ¶ 61,069 (2009); *North American Electric Reliability Corporation*, "Notice of No Further Review and Guidance Order," 132 FERC ¶ 61,182 (2010).

1. the violations constituted Northern States Power's second occurrence of violation of PRC-005-1 R2;[17]
2. MRO reported that Northern States Power was cooperative throughout the compliance enforcement process and had internal controls in place prior to completing the Mitigation Plans, as discussed above;
3. Northern States Power had a compliance program which MRO considered a mitigating factor, as discussed above;
4. MRO determined that the violations did not pose a serious or substantial risk to the reliability of the BPS, as discussed above
5. there was no evidence of any attempt to conceal a violation nor evidence of intent to do so;
6. there was no evidence that Northern States Power's violations were intentional; and
7. MRO reported that there were no other mitigating or aggravating factors or extenuating circumstances that would affect the assessed penalty.

For the foregoing reasons, the NERC BOTCC approved the Settlement Agreement and believes that the assessed penalty of two hundred and fifty thousand dollars ($250,000) is appropriate for the violations and circumstances at issue, and is consistent with NERC's goal to promote and ensure reliability of the BPS.

Pursuant to 18 C.F.R. § 39.7(e), the penalty will be effective upon expiration of the 30 day period following the filing of this Notice of Penalty with FERC, or, if FERC decides to review the penalty, upon final determination by FERC.

Attachments to be Included as Part of this Notice of Penalty

The attachments to be included as part of this Notice of Penalty are the following documents:

a) Settlement Agreement by and between MRO and Northern States Power executed April 12, 2013, included as Attachment a;
b) Record documents for the violation of COM-002-2 R2, included as Attachment b:
    1. Northern States Power's Mitigation Plan designated as MROMIT007207 submitted April 26, 2012;

[17] *Supra* note 10.

2. Northern States Power's Certification of Mitigation Plan Completion dated April 26, 2012;
3. MRO's Verification of Mitigation Plan Completion dated April 26, 2012;

c) Record documents for the violation of PRC-004-1 R1, included as Attachment c:

1. Northern States Power's Mitigation Plan designated as MROMIT007288 submitted May 4, 2012;
2. Northern States Power's Certification of Mitigation Plan Completion dated May 8, 2012 ;
3. MRO's Verification of Mitigation Plan Completion dated May 10, 2012;

d) Record documents for the violations of EOP-008-0 R1.5 and PRC-005-1 R2.1 , included as Attachment d:

1. Northern States Power's Compliance Audit Worksheet;
2. Northern States Power's Mitigation Plan designated as MROMIT006515 submitted December 19, 2011;
3. Northern States Power's Certification of Mitigation Plan Completion dated April 12, 2012;
4. MRO's Verification of Mitigation Plan Completion dated April 13, 2012;
5. Northern States Power's Mitigation Plan designated as MROMIT005992 submitted October 20, 2011;
6. Northern States Power's Certification of Mitigation Plan Completion dated August 10, 2012; and
7. MRO's Verification of Mitigation Plan Completion dated August 10, 2012.

A Form of Notice Suitable for Publication[18]

A copy of a notice suitable for publication is included in Attachment e.

[18] *See* 18 C.F.R § 39.7(d)(6).

Notices and Communications: Notices and communications with respect to this filing may be addressed to the following:

Gerald W. Cauley President and Chief Executive Officer North American Electric Reliability Corporation 3353 Peachtree Road NE Suite 600, North Tower Atlanta, GA 30326 (404) 446-2560 Charles A. Berardesco* Senior Vice President and General Counsel North American Electric Reliability Corporation 1325 G Street N.W., Suite 600 Washington, DC 20005 (202) 400-3000 (202) 644-8099 – facsimile charles.berardesco@nerc.net Daniel P. Skaar* President Midwest Reliability Organization 380 St. Peter Street, Suite 800 Saint Paul, MN 55102 P: 651-855-1731 dp.skaar@midwestreliability.org Sara E. Patrick* Vice President of Regulatory Affairs and Enforcement Midwest Reliability Organization 380 St. Peter Street, Suite 800 Saint Paul, MN 55102 P: 651-855-1708 se.patrick@midwestreliability.org	Sonia C. Mendonça* Assistant General Counsel and Director of Enforcement North American Electric Reliability Corporation 1325 G Street N.W. Suite 600 Washington, DC 20005 (202) 400-3000 (202) 644-8099 – facsimile sonia.mendonca@nerc.net Edwin G. Kichline* North American Electric Reliability Corporation Senior Counsel and Associate Director, Enforcement Processing 1325 G Street N.W. Suite 600 Washington, DC 20005 (202) 400-3000 (202) 644-8099 – facsimile edwin.kichline@nerc.net Tim O’Connor* Senior Vice President and Chief Nuclear Officer Xcel Energy Inc. 414 Nicollet Mall (MP4) Minneapolis, MN 55401 P: 612-330-6521 timothy.j.oconnor@xcelenergy.com

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Conclusion

NERC respectfully requests that the Commission accept this Notice of Penalty as compliant with its rules, regulations and orders.

Respectfully submitted,

/s/ Sonia Mendonça

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cc: Northern States Power (Xcel Energy)
Midwest Reliability Organization

Attachments

Attachment a

Settlement Agreement by and between MRO and Northern States Power executed April 12, 2013

a-1. Disposition of Violation, included as Addendum 1 to the Settlement Agreement

SETTLEMENT AGREEMENT

OF

MIDWEST RELIABILITY ORGANIZATION

AND

XCEL ENERGY SERVICES INC.

ON BEHALF OF NORTHERN STATES POWER

I. INTRODUCTION

1. Midwest Reliability Organization (MRO) and XCEL ENERGY SERVICES INC. representing two of its utility operating company affiliates, NORTHERN STATES POWER COMPANY, a Minnesota corporation, and NORTHERN STATES POWER COMPANY, a Wisconsin corporation (jointly "Northern States Power" or "NSP": NERC Compliance Registry ID# NCR01020) enter into this Settlement Agreement (Agreement) to resolve all outstanding issues arising from a preliminary and non-public assessment resulting in MRO's determination and finding, pursuant to the North American Electric Reliability Corporation (NERC) Rules of Procedure, of alleged violations by NSP of NERC Reliability Standards COM-002-2, R2 (Violation Identification Tracking Number MRO201100263); PRC-004-1, R1 (Violation Identification Tracking Number MRO201100268); EOP-008-0, R1.5 (Violation Identification Tracking Number MRO201100332); and PRC-005-1, R2.1 (Violation Identification Tracking Number MRO201100333).

2. NSP neither admits nor denies that the facts set forth for purposes of this Settlement Agreement constitute violations of NERC Reliability Standards COM-002-2, R2; PRC-004-1, R1; EOP-00809, R1.5; and PRC-005-1, R2.1, and has agreed to the assessed penalty of $250,000, in addition to other remedies and mitigation actions to mitigate the instant concerns and facilitate future compliance under the terms and conditions of the Settlement Agreement.

II. STIPULATION

3. The facts stipulated herein are stipulated solely for the purpose of resolving, between Northern States Power and MRO, the matters discussed herein and do not constitute stipulations or admissions for any other purpose. The attached Disposition Document is incorporated herein in its entirety. Northern States Power and MRO hereby stipulate and agree to the following:

Background

4. See Section I of the Disposition Document for a description of NSP.

5. See Section II of the Disposition Document for the description of the violations.

III. PARTIES' SEPARATE REPRESENTATIONS

STATEMENT OF MRO AND SUMMARY OF FINDINGS

6. On September 18, 2007, the MRO region experienced a category four[1] disturbance initiated by a transmission system conductor failure on the Prairie Island-Byron 345kV line. The category four disturbance included a cascade of multiple lines that form the Minnesota-Wisconsin Stability Interface (MWSI). The loss of these lines was followed by over frequency generator tripping and under frequency load shedding which resulted in the formation of system islands. North Dakota, Minnesota, Manitoba, part of South Dakota, and Saskatchewan separated from the Eastern Interconnection. Saskatchewan then separated from Manitoba and North Dakota.

7. On March 3, 2008, a Compliance Violation Investigation (CVI) was initiated by MRO. On March 5, 2008, NERC assumed leadership of the CVI.

8. On January 6, 2010, NERC issued a Preliminary Notice of Findings and Analysis (Preliminary Notice) to Northern States Power detailing the findings of alleged noncompliance with several NERC Reliability Standards.[2]

9. The CVI team determined that when issuing directives to the Generator Operators (GOP), the NSP Transmission Operator (TOP) failed to provide directives in a clear, concise manner and did not require the GOP repeat back the directives. MRO reviewed the voice recordings identified as Evidence Item 1-1 in the

[1]Classified by NERC as a category four due to the interconnected system separation and islanding of 1,000 MW of load or generation occurred. Category four events require a detailed event analysis to be conducted.

[2]The Notice of Preliminary Findings and Analysis, Non-Public Compliance Violation Investigation of the Xcel Energy, Northern States Power - NERC0001CVI included twelve findings of alleged non-compliance; three of the twelve findings related to PRC-004-1, R1 and two related to PRC-005-1, R2. Where there were multiple findings for the same Standard and Requirement, MRO consolidated the findings and assigned one violation tracking number which reduced the number of findings from twelve to nine. Two of those findings are addressed herein; COM-002-2, R2 (MRO201100263) and PRC-004-1, R1 (MRO201100268). The other seven findings have been dismissed; PRC-001-1, R1 (MRO201100264); PRC-001-1, R2 (MRO201100265); PRC-001-1, R3 (MRO201100266); PRC-001-1, R4 (MRO201100267); PRC-004-1, R3 (MRO201100269); PRC-005-1, R1 (MRO201100270); and PRC-005-1, R2 (MRO201100271).

Preliminary Notice and concurred with the CVI team that NSP failed to comply with COM-002-2, R2 when issuing directives during the event of September 18, 2007. While the absence of clear, concise directives and lack of use of three part communications during an emergency situation poses a significant risk to reliability of the Bulk Electric System (BES), in this instance, MRO determined that the violation posed a moderate risk and did not pose a serious or substantial risk to the reliability of the BES as further described in the Disposition Document.

10. The CVI Team also identified a possible violation of PRC-004-1, R1[3] because NSP did not complete the Corrective Action Plan for the misoperation of the Coon Creek—Terminal 345kV line protection system which occurred on June 22, 2007, four days after the date of mandatory compliance with NERC Reliability Standards. MRO concurred that NSP failed to complete the Corrective Action Plan, for the misoperation of the Coon Creek—Terminal 345kV line protection system, within the timeframe intended. MRO determined that this violation posed a moderate risk to reliability of the BES as further described in the Disposition Document.

11. During a regularly scheduled compliance audit conducted in February 2011, MRO determined that NSP failed to include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of its plan for loss of control center functionality at its Eau Claire, Wisconsin control center facility as required by EOP-008-0, R1.5. MRO determined that this violation posed a minimal risk to reliability of the BES because although NSP failed to completely test its plans for loss of control center functionality at its Eau Claire Control Center, the majority of the plan test was completed and complete plans had been developed. Further description of the violation and the risk assessment is provided in the Disposition Document.

12. During the compliance audit conducted in February 2011, MRO also determined that NSP was unable to provide evidence that certain protection system devices at its Monticello Nuclear Generating Plant and Prairie Island Nuclear Generating Plant had been maintained and tested within the defined intervals as required by PRC-005-1, R2.1. MRO determined that this violation posed a moderate risk to reliability of the BES because for a two year period, protection system components at both nuclear generating plans were not maintained and tested according to the defined intervals. Further description of the violation and the risk assessment is provided in the Disposition Document.

[3] The CVI team identified three findings related to PRC-004-1, R1. MRO consolidated these three findings into one violation and validated one instance of noncompliance with PRC-004-1, R1 related to the Coon Creek-Terminal misoperation addressed herein.

13. MRO agrees that this agreement is in the best interest of the parties and in the best interest of BES reliability.

STATEMENT OF NORTHERN STATES POWER

14. NSP neither admits nor denies that the facts set forth and agreed to by the parties for purposes of this Agreement constitute violations of COM-002-2, R2; PRC-004-1, R1; EOP-008-0, R1.5; and PRC-005-1, R2.1.

15. NSP has agreed to enter into this Settlement Agreement with MRO to avoid extended litigation with respect to the matters described or referred to herein, to avoid uncertainty, and to effectuate a complete and final resolution of the issues set forth herein. NSP agrees that this agreement is in the best interest of the parties and in the best interest of maintaining a reliable electric infrastructure.

IV. MITIGATING ACTIONS, REMEDIES AND SANCTIONS

16. MRO and NSP agree that NSP has completed and MRO has verified completion of the mitigating actions set forth in Section IV of the Disposition Document.

17. For purposes of settling any and all disputes arising from MRO's assessment of the investigation conducted by NERC of the September 18, 2007 system disturbance, and the Compliance Audit conducted by MRO in February 2011, MRO and NSP agree that on or after the effective date of this Agreement, NSP shall pay a monetary penalty of $250,000 to MRO, via wire transfer or check to an MRO account that will be outlined in an invoice sent to NSP within twenty calendar days after the Agreement is either approved by the Commission or is rendered effective by operation of law. Payment of this invoice shall be made within twenty days after the receipt of the invoice, and MRO shall notify NERC if the payment is not received.

18. Additionally, for purposes of settling any and all disputes arising from MRO's assessment of the investigation conducted by NERC of the September 18, 2007 system disturbance, and the Compliance Audit conducted by MRO in February 2011, MRO and NSP agree that NSP has or shall take the following action to prevent recurrence of these alleged violations and increase the reliability of the BES:

    i. NSP shall share its experience and lessons learned related to compliance with PRC-005-1 with at least three industry peer groups such as the National Generator Forum and the Mid Continent Compliance Forum. To complete this commitment, one of the three industry peer groups must be the Utilities Service Alliance (USA). USA is a not-for-profit cooperative designed to facilitate collaboration among its member utilities with nuclear facilities. USA works to reduce operating and maintenance costs, improve safety and performance, and provide innovation and leadership within the nuclear power industry.

ii. NSP shall enhance its corporate commitment to compliance by providing additional training and education from a third party provider to its Nuclear Business Unit related to compliance with NERC Reliability Standards. NSP commits to securing NERC Compliance training for at least six individuals from its Nuclear Business Unit representing positions such as: technical subject matter experts, NERC compliance technicians, and Regulatory Affairs personnel. (Personnel will include representatives from fleet and both sites.)

iii. NSP shall coordinate with and benchmark the adoption of NERC compliance efforts at two nuclear facilities owned and operated by two different entities. One of the nuclear facilities will be within the MRO region and one will be outside the MRO region.

iv. NSP will replace the solid state relays looking from the 345 kV system into the Generator Step Up (GSU) Transformer #1 and GSU Transformer #2 at the Prairie Island substation with microprocessor relays. The primary purpose of these relays is to clear faults on the 345kV connection between the substation and GSU. The relay replacement will occur concurrent with planned outages in Fall 2013 and Fall 2014. NSP estimates that the cost of the relay replacement will be $2,200,000.

NSP shall complete each of the above items i. through iii. within one year of signing this Settlement Agreement. NSP shall complete above item iv. by December 1, 2014. Additionally, NSP agrees that senior management from each of its nuclear stations (minimum of four individuals) shall attend either an MRO Compliance Committee meeting or an MRO Board of Directors meeting by the end of third quarter of 2013. Attendance at these meetings is intended to broaden the understanding of compliance with NERC Reliability Standards and enhance the commitment to compliance within the Nuclear Business Unit.

19. In order to facilitate MRO's need to communicate the status and provide accountability to the ERO (NERC), NSP will provide three status reports to MRO indicating the status of the commitments made in Paragraph 18 and when the actions were/are expected to be completed. The first status report is due to the MRO no later than 30 days after the six month anniversary of the effective date of the Settlement Agreement, and the second status report is due no later than 30 days after the one year anniversary of the effective date of the Settlement Agreement. The third status report is due by December 31, 2014, and will address the relay replacement anticipated to be complete in Fall 2014. NSP shall maintain records and other evidentiary material to support completion of the mitigation and remedies in this Settlement Agreement. Upon receipt of the report, MRO will validate that the actions resulting from this settlement are performed in

accordance with the terms and conditions of this Settlement Agreement. NSP shall submit this report to MRO in accordance with the confidentiality provisions of Section 1500 of the NERC Rules of Procedure.

20. MRO considered the specific facts and circumstances of the violations and NSP's actions in response to the violations in determining a proposed penalty that meets the requirement in Section 215 of the Federal Power Act that "[a]ny penalty imposed under this section shall bear a reasonable relation to the seriousness of the violation and shall take into consideration the efforts of such user, owner or operator to remedy the violation in a timely manner."[4] The factors considered by MRO Staff in the determination of the appropriate penalty are set forth in Section V of the Disposition Document.

21. Failure to comply with any of the terms and conditions agreed to herein, or any other conditions of this Settlement Agreement, shall be deemed to be either the same alleged violation that initiated this Settlement and/or an additional violation and may subject NSP to new or additional enforcement, penalty or sanction actions in accordance with the NERC Rules of Procedure. NSP shall retain all rights to defend against such additional enforcement actions in accordance with NERC Rules of Procedure.

V. ADDITIONAL TERMS

22. The signatories to the Settlement Agreement agree that they enter into the Settlement Agreement voluntarily and that, other than the recitations set forth herein, no tender, offer or promise of any kind by any member, employee, officer, director, agent or representative of MRO or NSP has been made to induce the signatories or any other party to enter into the Settlement Agreement.

23. MRO shall report the terms of all settlements of compliance matters to NERC. NERC will review the settlement for the purpose of evaluating its consistency with other settlements entered into for similar violations or under other, similar circumstances. Based on this review, NERC will either approve the settlement or reject the settlement and notify MRO and NSP of changes to the settlement that would result in approval. If NERC rejects the settlement, NERC will provide specific written reasons for such rejection and MRO will attempt to negotiate a revised settlement agreement with NSP including any changes to the settlement specified by NERC. If a settlement cannot be reached, the enforcement process shall continue to conclusion. If NERC approves the settlement, NERC will (i) report the approved settlement to the Commission for the Commission's review and approval by order or operation of law and (ii) publicly post this Settlement Agreement.

[4] 16 U.S.C. § 824o(e)(6).

24. This Settlement Agreement shall become effective upon the Commission's approval of the Settlement Agreement by order or operation of law as submitted to it or as modified in a manner acceptable to the parties.

25. NSP agrees that this Settlement Agreement, when approved by NERC and the Commission, shall represent a final settlement of all matters set forth herein and NSP waives its right to further hearings and appeal, unless and only to the extent that NSP contends that any NERC or Commission action on the Settlement Agreement contains one or more material modifications to the Settlement Agreement. In the event NSP fails to comply with any of the stipulations, remedies, sanctions or additional terms, as set forth in this Settlement Agreement, MRO will initiate enforcement, penalty, or sanction actions against NSP to the maximum extent allowed by the NERC Rules of Procedure, up to the maximum statutorily allowed penalty. Except as otherwise specified in this Settlement Agreement, NSP shall retain all rights to defend against such enforcement actions, also according to the NERC Rules of Procedure.

26. NSP consents to the use of MRO's determinations, findings, and conclusions set forth in this Agreement for the purpose of assessing the factors, including the factor of determining the company's history of violations, in accordance with the NERC Sanction Guidelines and applicable Commission orders and policy statements. Such use may be in any enforcement action or compliance proceeding undertaken by NERC and/or any Regional Entity; provided, however, that NSP does not consent to the use of the specific acts set forth in this Settlement Agreement as the sole basis for any other action or proceeding brought by NERC and/or MRO, nor does NSP consent to the use of this Settlement Agreement by any other party in any other action or proceeding

27. Each of the undersigned warrants that he or she is an authorized representative of the entity designated, is authorized to bind such entity and accepts the Settlement Agreement on the entity's behalf.

28. The undersigned representative of each party affirms that he or she has read the Settlement Agreement, that all of the matters set forth in the Settlement Agreement are true and correct to the best of his or her knowledge, information and belief, and that he or she understands that the Settlement Agreement is entered into by such party in express reliance on those representations, provided, however, that such affirmation by each party's representative shall not apply to the other party's statements of position set forth in Section III of this Settlement Agreement.

29. The Settlement Agreement may be signed in counterparts.

30. This Settlement Agreement is executed in duplicate, each of which so executed shall be deemed to be an original.

Agreed to and accepted:

Teresa M. Mogensen Vice President, Transmission Xcel Energy Services Inc. Authorized agent for Northern States Power Company. A Minnesota corporation, and Northern States Power Company, A Wisconsin corporation	4 - 12 - 13 Date
Tim O'Connor Senior Vice President and Chief Nuclear Officer Xcel Energy Inc.	4-12-13 Date
Daniel P. Skaar President and CEO Midwest Reliability Organization	April 5, 2013 Date
Sara E. Patrick Vice President, Enforcement and Regulatory Affairs Midwest Reliability Organization	April 4, 2013 Date

DISPOSITION OF VIOLATION[1]
Dated April 2, 2013

NERC TRACKING NO.	REGIONAL ENTITY TRACKING NO.	NOC#
MRO201100263	**MRO201100263**	
MRO201100268	**MRO201100268**	
MRO201100332	**MRO201100332**	
MRO201100333	**MRO201100333**	

REGISTERED ENTITY
Northern States Power (NSP)

NERC REGISTRY ID
NCR01020

REGIONAL ENTITY
Midwest Reliability Organization (MRO)

I. REGISTRATION INFORMATION

ENTITY IS REGISTERED FOR THE FOLLOWING FUNCTIONS:

BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
X	X	X	X		X		X		X		X	X	X	X
5-30-2007	**5-30-2007**	**5-30-2007**	**5-30-2007**		**5-30-2007**		**5-30-2007**		**5-30-2007**		**5-30-2007**	**5-30-2007**	**5-30-2007**	**5-30-2007**

* VIOLATIONS APPLY TO SHADED FUNCTIONS

DESCRIPTION OF THE REGISTERED ENTITY

Northern States Power Company, a Minnesota corporation (NSPM), and Northern States Power Company, a Wisconsin corporation (NSPW), are collectively referred to as Northern States Power (NSP). NSPM and NSPW operate a single integrated generation and transmission system with ownership of assets bifurcated at the Minnesota/Wisconsin border.

NSP serves customers in portions of Minnesota, North Dakota, eastern South Dakota, western Wisconsin, and the Upper Peninsula of Michigan. NSP has approximately 1.6 million electric customers.

[1] For purposes of this document and attachments hereto, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, alleged or confirmed violation.

NSP is a summer peaking system. NSP operates at the following transmission voltages: 34.5 kV, 69 kV, 88 kV, 115 kV, 161 kV, 230 kV, 345 kV, and 500 kV. NSP owns an estimated total of 7,216 miles of transmission lines. There are a total of 143 interconnected points on the systems operated within the NSP System at 69 kV and above.

II. VIOLATION INFORMATION

RELIABILITY STANDARD	REQUIREMENT(S)	SUB-REQUIREMENT(S)	VRF(S)	VSL(S)	Applicable Functions
COM-002-2	**2**		**Medium**	**Severe**[2]	**BA, TOP**
PRC-004-1	**1**		**High**	**Moderate**	**DP, TO**
EOP-008-0	**1**	**1.5**	**Medium**	**Severe**	**BA, TOP**
PRC-005-1	**2**	**2.1**	**High**	**Lower**	**DP, GO, TO**

Tracking ID: MRO201100263 (COM-002-2, R2)

TEXT OF RELIABILITY STANDARD AND REQUIREMENT

The purpose statement of COM-002-2 provides: To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.

Requirement 2 of the Standard provides: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

VIOLATION DESCRIPTION

Just three months into mandatory compliance with NERC Reliability Standards, on September 18, 2007, the MRO region experienced a category four[3] disturbance initiated by a transmission system conductor failure on the Prairie Island-Byron 345kV line, which resulted in tripping of multiple 345kV lines that form the Minnesota-Wisconsin Stability Interface (MWSI). The loss of these 345kV lines was followed by over frequency generator tripping and under frequency load shedding which resulted in the formation of system islands. North Dakota, Minnesota, Manitoba, part of South Dakota, and Saskatchewan separated from the Eastern Interconnection. Saskatchewan then separated from Manitoba and North Dakota.

[2] Reliability Standard COM-002-2, R2 did not have an assigned VSL on September 18, 2007. Additionally, there were no "Levels of Noncompliance" applicable to Requirement 2 on September 18, 2007. Subsequently, VSL assignments for COM-002-2, R2 were approved. The "Severe" VSL applies where the responsible entity failed to provide a directive in a clear, concise and definitive manner when required.

[3] Classified by NERC as a category four due to the interconnected system separation and islanding of 1,000 MW of load or generation. Category four events require a detailed event analysis to be conducted.

Various MRO Registered Entities in the first island were reconnected to the Eastern Interconnection in less than 10 minutes through automatic reclosing of a number of open transmission lines between that island and the Eastern Interconnection. The second island was reconnected to the Eastern Interconnection in 58 minutes. The event resulted in load loss of approximately 9 MW in the United States.[4]

On March 3, 2008, a Compliance Violation Investigation (CVI) was initiated by MRO. On March 5, 2008, the North American Electric Reliability Corporation (NERC) assumed leadership of the CVI. On January 6, 2010, NERC issued a Preliminary Notice of Findings and Analysis (Preliminary Notice) to NSP detailing the alleged findings of noncompliance with several NERC Reliability Standards[5]. NSP responded to the Preliminary Notice and did not accept the NERC CVI findings.

The CVI team determined that when issuing directives to the Generator Operators (GOP), the NSP Transmission Operator (TOP) failed to provide directives in a clear, concise manner and did not require the GOP repeat back the directives. MRO reviewed the voice recordings identified as Evidence Item 1-1 in the Preliminary Notice and concurred with the CVI team.

MRO identified four telephonic communications that were not clear and concise and/or did not fully utilize three-part communication. The first communication occurred during the event where the NSP TOP directs, “We better get 3 Wheatons on there.” While it is clear that the reference is to generation at the NSP Wheaton Generating Station which has six units, it is not clear which units or what amount of generation is needed. Additionally, the response did not include a repeat of the directive or request for clarity, instead the recipient GOP stated, “Yeah, we’re gonna go right now.” The second communication identified by MRO also occurred during the event where the TOP stated, “Take Sherco 2 off control and run units 1 and 2 at 350.” The recipient GOP stated, “You want to run them at 350 a piece?” The issuer TOP responded “Yes.” While this repeated part of the directive, it did not include the full directive and the acknowledgement did not clarify all actions included in the directive, i.e., there was no reference

[4] The September 18, 2007 event resulted in load loss of approximately 787 MW, with only 9 MW of the load loss occurring in the United States. The majority of the load loss, approximately 769 MW, occurred in the service area of a neighboring entity that is not subject to FERC jurisdiction. According to the Event Analysis Report, ‘[t]he causal factor for the separation of the [Canadian entity’s] system from the first island was the sensitive, uncoordinated settings of over-frequency protection on a range of thermal generators. Premature tripping of these units resulted in the separation of the [Canadian entity’s] system from the first island, and in significant load shedding in the [Canadian entity’s] system.” An additional 9 MW of load loss occurred in the service area of another neighboring entity that is not subject to FERC jurisdiction.

[5] The Notice of Preliminary Findings and Analysis, Non-Public Compliance Violation Investigation of the Xcel Energy, Northern States Power - NERC0001CVI included twelve findings of non-compliance; three of the twelve findings related to PRC-004-1, R1 and two related to PRC-005-1, R2. Where there were multiple findings for the same Standard and Requirement, MRO consolidated the findings and assigned one violation tracking number which reduced the number of findings from twelve to nine. Two of those findings are addressed herein; COM-002-2, R2 (MRO201100263) and PRC-004-1, R1 (MRO201100268). The other seven findings have been dismissed; PRC-001-1, R1 (MRO201100264); PRC-001-1, R2 (MRO201100265); PRC-001-1, R3 (MRO201100266); PRC-001-1, R4 (MRO201100267); PRC-004-1, R3 (MRO201100269); PRC-005-1, R1 (MRO201100270); and PRC-005-1, R2 (MRO201100271).

to taking Sherco 2 “off control.” The third communication also occurred during the event, where the TOP stated, “Have 3 drop about 100 too, if they can.” The recipient GOP responded, “Ok. More than what they just fell off frequency?” The issuer TOP stated, “Yes, it’s all frequency.” In both the second and third instances, the directive may have been clear and concise, but three-part communication was not utilized during an emergency situation. The final communication occurred during restoration where the TOP directs, “Put Shercos back on control, or, if you want to, move them up a little bit and then put them on.” The recipient GOP response is “Ok.” Similar to the first communication, it is clear that the reference is to generators at the Sherco Generating Station, which has three units with a combined capacity of 2400 MW, it not clear which units or what amount of generation is being requested. Again, the response did not include a repeat of the directive or request for clarity.

MRO concluded that NSP, as the TOP, failed to provide directives in a clear, concise and definitive manner, and also failed to require the recipient GOP repeat back the directive as required by COM-002-2, R2.

RELIABILITY IMPACT STATEMENT- POTENTIAL AND ACTUAL

While the absence of clear, concise directives and lack of use of three part communications during an emergency situation poses a significant risk to reliability of the Bulk Power System (BPS), in this instance, MRO determined that the violation posed a moderate risk and did not pose a serious or substantial risk to the reliability of the BPS. It is critically important to BPS reliability that directives be issued in a clear, concise and definitive manner and that three part communications be utilized during an emergency situation. When this is not the case, the potential for misunderstandings, misdirection, and miscommunication is high and can result in, contribute to, or exacerbate a system disturbance.

In this instance, although MRO concluded that certain directives were not clear, concise and definitive and that three-part communication was not fully utilized, the directives given to the applicable personnel were followed and actions taken as intended by the issuer of the directives. Because the directives were correctly implemented, the directives met the purpose stated in Reliability Standard COM-002-2 of ensuring effective communications by operating personnel. Further, there is no evidence that the four communications contributed to or exacerbated the event, but were steps taken to contain the event and ultimately restore the system.

In assessing the risk posed by this violation, MRO considered the following:

- all four of the communications at issue involved personnel who had access to the same tools (i.e., the NSP Energy Management System (EMS)) and these same personnel were able to see the same information regarding system status;
- the personnel were properly equipped to respond to the directives because of the shared tools with the same information and familiarity of the system;
- the first island was reconnected in just over 8 minutes and the Event Analysis Report commended the coordination and communication efforts of those involved, including NSP; and,

- the potential risk from reliance on familiarity of operating personnel without proper use of three part communication and clear, concise and definitive directives. For example, if the personnel involved in the event were different, the lack of clear, concise and definitive communications and the failure to use three part communication during an emergency situation, could have resulted in a much greater risk to the reliability of the BPS.

While the directives were followed and actions taken as intended by the issuer, reducing the potential risk, taking the facts and circumstances into account, MRO determined that this violation posed a moderate risk to reliability of the BPS.

Tracking ID: MRO201100268 (PRC-004-1, R1)

TEXT OF RELIABILITY STANDARD AND REQUIREMENT

The purpose statement of PRC-004-1 provides: Ensure all transmission and generation Protection System misoperations affecting the reliability of the BPS are analyzed and mitigated.

Requirement 1 of the Standard provides: The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System misoperations and shall develop and implement a Corrective Action Plan to avoid future misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.

VIOLATION DESCRIPTION

The CVI Team identified a possible violation of PRC-004-1, R1[6] because NSP did not complete the Corrective Action plan for the misoperation of the Coon Creek—Terminal 345kV line protection system which occurred on June 22, 2007, four days after the date of mandatory compliance with NERC Reliability Standards.

Upon review of the facts, circumstances, and evidence provided by NERC, MRO concurred that NSP did not complete the Corrective Action plan for the misoperation of the Coon Creek—Terminal 345kV line protection system, which occurred on June 22, 2007, within the timeframe intended. After the misoperation NSP conducted analysis and developed a Corrective Action plan with a proposed completion date of August 10, 2007. According to the statement of NSP's Principal Specialty Engineer, testing for certain relays associated with the misoperation had not been completed.

As part of the Investigation, the CVI team conducted a Spot Check on February 24-26, 2009. In response to a request during the Spot Check, NSP concluded that it could not affirmatively represent to NERC that the required work had been performed. NSP had developed a Corrective Action Plan for the June 22, 2007 Coon Creek–Terminal 345kV line misoperation that included

[6] The CVI team identified three findings related to PRC-004-1, R1. MRO consolidated these three findings into one violation and validated one instance of noncompliance with PRC-004-1, R1 related to the Coon Creek-Terminal misoperation addressed herein.

a list of maintenance activities intended to prevent recurrence of the misoperation. These maintenance activities were specified in a Work Request that triggered issuance of five work orders. Only two of these five work orders were completed as scheduled. These two work orders related to the line relay that misoperated and the associated telecommunication. NSP was unable to provide documentation to establish that the remaining three work orders were completed within the timeframe scheduled by NSP. Upon discovery, NSP issued a new Work Request and associated Work Orders and the work was completed on March 20, 2009.

RELIABILITY IMPACT STATEMENT- POTENTIAL AND ACTUAL

MRO determined that this violation posed a moderate risk to reliability of the BPS. Although NSP developed a Corrective Action Plan for the June 22, 2007 Coon Creek–Terminal 345kV line misoperation that included a list of maintenance activities intended to prevent recurrence of the misoperation, the Corrective Action Plan was not completed within the timeframe intended by NSP. While the relay did not misoperate between the time that the maintenance activities were initially identified and the time that the maintenance activities were actually completed, the NSP Corrective Action Plan was prematurely closed. While MRO determined that this misoperation was not related to the event which occurred on September 18, 2007, had it not been for the Spot Check conducted as a result of the CVI, it is not known whether NSP would have determined, or when NSP would have determined, that it had not completed the Corrective Action Plan as scheduled. MRO considered that the improper closing of the maintenance activities without a system to verify proper completion of the Corrective Action Plan posed a risk to reliability of the BPS. In addition, MRO considered that this transmission line is located in the Twin Cities metropolitan area, is associated with a voltage level of 345kV, is interconnected with three surrounding 345kV transmission lines, and determined that the violation posed a moderate risk to the BPS.

Tracking ID: MRO201100332 (EOP-008-0, R1)

TEXT OF RELIABILITY STANDARD AND REQUIREMENT

The purpose statement of EOP-008-00 provides: Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable.

Requirement 1 of the Standard provides: Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:

> R1.5. The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.

VIOLATION DESCRIPTION

During a regularly scheduled compliance audit conducted between February 14, 2011 and February 18, 2011, MRO determined that NSP failed to include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of its plan for loss of control center functionality. As a Transmission Operator, NSP maintains and operates two control centers. The main control center is located in Minneapolis, Minnesota and provides transmission operations for portions of Minnesota, South Dakota, and North Dakota. The second control center is located in Eau Claire, Wisconsin and provides transmission operations for the Wisconsin portion of the NSP system.

MRO determined that NSP had developed and tested its plans for loss of control center functionality for the Minneapolis Control Center. NSP had also developed plans for loss of control center functionality at the Eau Claire Control Center, but had failed to complete the annual testing of the plans.

The plan for evacuation of the Eau Claire Control Center consists of information management; contacting the Minneapolis Control Center to request that it assume control of the Eau Claire Control Center system; printing out the status of several 69 kV capacitor banks; logging out of the EMS terminal at the Eau Claire Control Center; the Minneapolis Control Center issuing a Mission Mode alert, assuring communication ability via emergency cell phone; and reassembling the Eau Claire Control Center personnel at the NSPW Western Avenue facility in Eau Claire, the designated gathering point. MRO determined that NSP had not tested the portion of the plan that included the system operator assuring communication ability via emergency cell phone and driving approximately 5 miles to the Western Avenue Service Center located in Eau Claire.

On February 23, 2011, within one week of the compliance audit, NSP successfully tested and documented completion of the Eau Claire Control Center plans for loss of control center functionality.

RELIABILITY IMPACT STATEMENT- POTENTIAL AND ACTUAL

MRO determined that this violation posed a minimal risk to reliability of the BPS because although NSP failed to completely test its plans for loss of control center functionality at its Eau Claire Control Center, the majority of the plan test was completed and complete plans had been developed. Both of the NSP Control Centers operate from the primary Energy Management System (EMS) in the Minneapolis Control Center. Therefore, in the event of evacuation of the Eau Claire Control Center, the operation of the primary EMS would be unaffected. The Minneapolis Control Center has a terminal with the Eau Claire Control Center authorities configured. Each weekday morning, Transmission Operators in the Minneapolis Control Center log into the terminal and verify that it is operational. MRO determined that he failure to test the final part of the plans for loss of control center functionality (e.g. driving 5 miles and making a phone call) had minimal impact to the reliability to the BPS.

Tracking ID: MRO201100333 (PRC-005-1, R2)

TEXT OF RELIABILITY STANDARD AND REQUIREMENT

The purpose statement of PRC-005-1 provides: To ensure all transmission and generation Protection Systems affecting the reliability of the BES are maintained and tested.

Requirement 2 of the Standard provides: Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:

R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

VIOLATION DESCRIPTION

During the pre-audit documentation review process for a regularly scheduled compliance audit conducted between February 14, 2011 and February 18, 2011, MRO requested relay records associated with a list of randomly selected stations. After receiving the request, NSP notified MRO that it was not able to provide evidence that certain relays had been tested within the established interval.

NSP reported that the 1N2 and 1N6 relay schemes at the Monticello Nuclear Generating Plant (MNGP) were not tested within their respective established intervals. The 1N2 relay scheme was due to be tested by October 2006 and was deferred in accordance with NSP's Protection System Maintenance and Testing Program until October 2008. However, the 1N2 relay scheme was not tested until November 5, 2010. The results of the November 5, 2010 test were satisfactory and indicated that the relay scheme was capable of performing its protective function during the period the testing exceeded the established interval. The 1N6 relay scheme was required to be tested by March 2010, but NSP could not provide evidence that the test was conducted or properly deferred. The 1N6 relay scheme was tested on February 13, 2011 and was found in calibration and functional.

NSP further reported that it had initiated an internal investigation into the cause of not performing the testing as scheduled and an extent of conditions review. NSP determined the cause in both instances was human error in not following established procedures. With regard to the 1N2 relay scheme, the test was properly deferred until October 2008 but was erroneously marked as complete in another work order. With regard to the 1N6 relay scheme, the test was scheduled to be conducted during the spring 2009 scheduled outage. However, the test was not deferred and the activity was not timely identified as incomplete or past due because outage coded maintenance and testing was tracked manually, rather than through an automated or computerized method.

As part of the Mitigation Plan process, NSP performed a comprehensive review of the protection system maintenance and testing records at its two nuclear facilities, MNGP and Prairie Island Nuclear Generating Plant (PINGP). During this review, NSP identified additional protection system components that had not been tested and maintained within the defined intervals. NSP failed to perform required functional and calibration testing associated with 5 of its 234 protection relays, 9 of its 234 DC control circuits, 6 of its 73 current and voltage sensing devices at PINGP. All of these components exceeded the 6 year maintenance and testing interval by 1 year and 8 months. NSP did not identify any issue when these components were tested.

NSP also failed to perform required functional and calibration testing associated with 8 of its 67 protection relays subject to PRC-005-1, R2 and 8 of its 75 DC control circuits at MNGP. Maintenance and testing of these protection system components exceeded the 4 year interval by 1 year for half of the protective relays and DC control circuits and the other half of the identified components exceeded the 4 year interval by 5 years. NSP did not identify any issue when these components were tested.

RELIABILITY IMPACT STATEMENT- POTENTIAL AND ACTUAL

MRO determined that this violation posed a moderate risk to reliability of the BPS because for a two year period, protection system components at both nuclear generating plants were not maintained and tested according to the defined intervals. The combined generation capability of these two generation plants is approximately 1700 MW. The plants generate about 30 percent of the electricity used by NSP's customers in the Upper Midwest. PINGP is located about 40 miles southeast of Minneapolis-Saint Paul. MNGP is located approximately 40 miles northwest of Minneapolis-Saint Paul. Based on the total generation output, location, and the interconnection of these generating plants with the BPS, MRO determined that this violation posed a moderate risk to reliability of the BPS.

IS THERE A SETTLEMENT AGREEMENT YES ☒ NO ☐

WITH RESPECT TO THE VIOLATION(S), REGISTERED ENTITY
NEITHER ADMITS NOR DENIES IT (SETTLEMENT ONLY) YES ☒
ADMITS TO IT YES ☐
DOES NOT CONTEST IT (INCLUDING WITHIN 30 DAYS) YES ☐

WITH RESPECT TO THE ASSESSED PENALTY OR SANCTION, REGISTERED ENTITY
ACCEPTS IT/ DOES NOT CONTEST IT YES ☒

III. DISCOVERY INFORMATION

METHOD OF DISCOVERY
SELF-REPORT ☐
SELF-CERTIFICATION ☐
COMPLIANCE AUDIT ☒
COMPLIANCE VIOLATION INVESTIGATION ☒
SPOT CHECK ☐
COMPLAINT ☐
PERIODIC DATA SUBMITTAL ☐
EXCEPTION REPORTING ☐

DURATION DATE(S):

Tracking ID: MRO201100263 (COM-002-2, R2):

September 18, 2007 when the recordings from the event indicate that clear, concise and direct communication with three part communication was not utilized.

Tracking ID: MRO201100268 (PRC-004-1, R1):

August 10, 2007 when the Corrective Action plan was scheduled to be complete until March 20, 2009 when the Corrective Action plan was completed.

Tracking ID: MRO201100332 (EOP-008-0, R1):

January 1, 2008 when testing of the plans for loss of control center function for the Eau Claire Control Center was not completed until February 23, 2011 when the Eau Claire Control Center plans for loss of control center function were fully tested.

Tracking ID: MRO201100333 (PRC-005-1, R2):

November 1, 2008 when the 1N2 relay scheme exceeded the October 2008 scheduled testing date until all maintenance and testing was completed on April 30, 2012.

DATE DISCOVERED BY OR REPORTED TO REGIONAL ENTITY

January 6, 2010, NERC issued a Preliminary Notice of Findings and Analysis for NERC0001CVI. February 14, 2011, NERC transferred compliance enforcement responsibility to MRO. This includes violation tracking numbers MRO201100263 and MRO201100268.

January 31, 2011, NSP notified MRO of a possible violation of PRC-005-1, R2 (MRO201100333) discovered while responding to a pre-audit information request in advance of a regularly scheduled compliance audit conducted between February 14, 2011 and February 18, 2011. During this compliance audit, MRO discovered a possible violation of EOP-008-0, R1 (MRO201100332).

IS THE VIOLATION STILL OCCURRING
YES ☐ NO ☒
IF YES, EXPLAIN

REMEDIAL ACTION DIRECTIVE ISSUED YES ☐ NO ☒
PRE TO POST JUNE 18, 2007 VIOLATION YES ☐ NO ☒

IV. MITIGATION INFORMATION

Tracking ID: MRO201100263 (COM-002-2, R2)

FOR FINAL ACCEPTED MITIGATION PLAN:

MITIGATION PLAN NO.	**MROMIT007207**
DATE SUBMITTED TO REGIONAL ENTITY	**April 26, 2012**
DATE ACCEPTED BY REGIONAL ENTITY	**April 26, 2012**
DATE APPROVED BY NERC	**January 10, 2013**[7]
DATE PROVIDED TO FERC	**January 10, 2013**

IDENTIFY AND EXPLAIN ALL PRIOR VERSIONS THAT WERE ACCEPTED OR REJECTED, IF APPLICABLE

N/A

MITIGATION PLAN COMPLETED YES ☒ NO ☐

EXPECTED COMPLETION DATE	**June 30, 2010**
EXTENSIONS GRANTED	**N/A**
ACTUAL COMPLETION DATE	**June 18, 2010**
DATE OF CERTIFICATION LETTER	**April 26, 2012**
CERTIFIED COMPLETE BY REGISTERED ENTITY AS OF	**June 18, 2010**
VERIFIED COMPLETE BY REGIONAL ENTITY AS OF	**June 18, 2010**

ACTIONS TAKEN TO MITIGATE THE ISSUE AND PREVENT RECURRENCE

1. Developed control center communications procedure.
2. Developed training for control center communications procedure.
3. Provided training for control center communications.

LIST OF EVIDENCE REVIEWED BY REGIONAL ENTITY TO EVALUATE COMPLETION OF MITIGATION PLAN (FOR CASES IN WHICH MITIGATION IS NOT YET COMPLETED, LIST EVIDENCE REVIEWED FOR COMPLETED MILESTONES)

1. List of operators and completion dates for Communications Protocol Training
2. List of other Xcel personnel and completion dates for Communications Protocol Training

[7] At the time the Mitigation Plan was accepted by MRO, the system of reporting to NERC was transitioning. Although a Mitigation Plan Number was assigned in the system which occurs upon submittal to NERC, it appears that NERC did not have a copy of the Mitigation Plan accepted by MRO. Upon determining that the Mitigation Plan had not been approved by NERC, MRO resubmitted the plan for NERC approval and forwarding to FERC.

3. Communications Protocol Training document
4. 4 voice recordings from September 18, 2007

Tracking ID: MRO201100268 (PRC-004-1, R1):

FOR FINAL ACCEPTED MITIGATION PLAN:

MITIGATION PLAN NO.	**MROMIT007288**
DATE SUBMITTED TO REGIONAL ENTITY	**May 4, 2012**
DATE ACCEPTED BY REGIONAL ENTITY	**May 7, 2012**
DATE APPROVED BY NERC	**May 30, 2012**
DATE PROVIDED TO FERC	**June 1, 2012**

IDENTIFY AND EXPLAIN ALL PRIOR VERSIONS THAT WERE ACCEPTED OR REJECTED, IF APPLICABLE

N/A

MITIGATION PLAN COMPLETED YES ☒ NO ☐

EXPECTED COMPLETION DATE	**August 1, 2010**
EXTENSIONS GRANTED	**N/A**
ACTUAL COMPLETION DATE	**July 1, 2010**
DATE OF CERTIFICATION LETTER	**May 8, 2012**
CERTIFIED COMPLETE BY REGISTERED ENTITY AS OF	**July 1, 2010**
VERIFIED COMPLETE BY REGIONAL ENTITY AS OF	**July 1, 2010**

ACTIONS TAKEN TO MITIGATE THE ISSUE AND PREVENT RECURRENCE

1. Completed the Corrective Action Plan identified for the misoperation of the Coon Creek-Terminal line on March 20, 2009.
2. Created a new System Protection Engineering area responsible for management of the misoperation analysis and corrective action process.
3. Reviewed and revised the Xcel Energy misoperation process/procedure.

LIST OF EVIDENCE REVIEWED BY REGIONAL ENTITY TO EVALUATE COMPLETION OF MITIGATION PLAN (FOR CASES IN WHICH MITIGATION IS NOT YET COMPLETED, LIST EVIDENCE REVIEWED FOR COMPLETED MILESTONES)

1. XEL-PRO-TransmProtSysMisOpProcedure.pdf
2. XEL-PRO-TransmProtSystMisOpInvestProcessMap.pdf
3. XES-17 Work Orders for Coon Creek-Terminal.pdf
4. System Protection Engineering Organization Chart, dated April 5, 2012

Tracking ID: MRO201100332 (EOP-008-0, R1):

FOR FINAL ACCEPTED MITIGATION PLAN:

MITIGATION PLAN NO.	**MROMIT006515**
DATE SUBMITTED TO REGIONAL ENTITY	**December 19, 2011**
DATE ACCEPTED BY REGIONAL ENTITY	**December 19, 2011**
DATE APPROVED BY NERC	**January 22, 2012**
DATE PROVIDED TO FERC	**January 26, 2012**

IDENTIFY AND EXPLAIN ALL PRIOR VERSIONS THAT WERE ACCEPTED OR REJECTED, IF APPLICABLE **N/A**

MITIGATION PLAN COMPLETED YES ☒ NO ☐

EXPECTED COMPLETION DATE	**April 30, 2012**
EXTENSIONS GRANTED	**N/A**
ACTUAL COMPLETION DATE	**April 12, 2012**
DATE OF CERTIFICATION LETTER	**April 12, 2012**
CERTIFIED COMPLETE BY REGISTERED ENTITY AS OF	**April 12, 2012**
VERIFIED COMPLETE BY REGIONAL ENTITY AS OF	**April 12, 2012**

ACTIONS TAKEN TO MITIGATE THE ISSUE AND PREVENT RECURRENCE

1. Created an overall test plan that describes the procedures and responsibilities for conducting periodic tests, at least annually, for loss of a primary control center.
2. Conducted a post-test review of the Loss of Control Center exercise and documented and incorporated identified improvements.
3. Performed a comprehensive review of all requirements in EOP-008-0.

LIST OF EVIDENCE REVIEWED BY REGIONAL ENTITY TO EVALUATE COMPLETION OF MITIGATION PLAN (FOR CASES IN WHICH MITIGATION IS NOT YET COMPLETED, LIST EVIDENCE REVIEWED FOR COMPLETED MILESTONES)

1. The 2010 plan subject to EOP-008 R 1.5 for the Eau Claire Control Center.
2. Evidence that Eau Claire Control Center Transmission operators received training regarding EOP-008-0 R1 in 2008, 2009 and 2010.
3. A summary regarding testing of the Eau Claire Control Center loss of control center function plan.

Tracking ID: MRO201100333 (PRC-005-1, R2):

FOR FINAL ACCEPTED MITIGATION PLAN:

MITIGATION PLAN NO.	**MROMIT005992**
DATE SUBMITTED TO REGIONAL ENTITY	**October 20, 2011**
DATE ACCEPTED BY REGIONAL ENTITY	**October 20, 2011**
DATE APPROVED BY NERC	**January 22, 2012**
DATE PROVIDED TO FERC	**January 26, 2012**

IDENTIFY AND EXPLAIN ALL PRIOR VERSIONS THAT WERE ACCEPTED OR REJECTED, IF APPLICABLE **N/A**

MITIGATION PLAN COMPLETED YES ☒ NO ☐

EXPECTED COMPLETION DATE	**April 30, 2012**
EXTENSIONS GRANTED	**N/A**
ACTUAL COMPLETION DATE	**April 30, 2012**
DATE OF CERTIFICATION LETTER	**August 10, 2012**
CERTIFIED COMPLETE BY REGISTERED ENTITY AS OF	**April 30, 2012**
VERIFIED COMPLETE BY REGIONAL ENTITY AS OF	**April 30, 2012**

ACTIONS TAKEN TO MITIGATE THE ISSUE AND PREVENT RECURRENCE

1. Tested the 1N6 relay scheme on February 13, 2011.
2. Verified that Monticello Nuclear Generating Plant (MNGP) PRC-005 related tests have been performed in accordance with the established intervals.
3. Verified that the Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2 related tests have been performed in accordance with the established intervals.
4. Identified and tracked all MNGP and PINGP PRC-005 devices due to be tested prior to January 1, 2012 to ensure timely completion of scheduled activities.
5. Performed a follow-up review of nuclear site protective relay systems and validated the identified scope of components to be tracked as PRC-005 related.
6. Verified all identified components have been tested within the established interval.
7. Completed an investigation to determine the cause of the missed tests and established corrective actions.
8. Developed and implemented an additional code to flag PRC-005 related protection systems in the equipment database. This flag allows these devices to be prioritized and queried for tracking/reporting purposes.
9. Revised applicable site-specific and fleet level procedures to ensure PRC-005 related activities are addressed. These changes include:
    a. The creation of a document that clearly ties all pieces of the existing protection system maintenance and testing program together;
    b. Require an additional level of review for the testing of PRC-005 components;
    c. Increase the priority level of PRC-005 related testing and maintenance;
    d. Increase the rigor of review and approval.

10. Issued a formal communication to the impacted maintenance, engineering, and scheduling personnel to increase awareness of PRC-005 testing requirements.
11. Disseminated to all electrical maintenance and engineering personnel an information package that provides additional guidance on mandatory NERC compliance.
12. Performed a training analysis to assess the need for additional electrical maintenance and engineering training on NERC compliance.
13. Developed and implemented a fleet lesson plan for NERC Standards applicable to electrical maintenance and engineering.
14. Performed independent checks for all relay schemes scheduled to be tested prior to March 31, 2012 to ensure testing was completed prior to the required due dates.

LIST OF EVIDENCE REVIEWED BY REGIONAL ENTITY TO EVALUATE COMPLETION OF MITIGATION PLAN (FOR CASES IN WHICH MITIGATION IS NOT YET COMPLETED, LIST EVIDENCE REVIEWED FOR COMPLETED MILESTONES)

1. 8050-03 (PE 002G-TC) 2011.pdf, Prairie Island relay test report
2. FP-MA-PRC-051.pdf, Revised PRC-005 related program documentation
3. FP-PE-PM-01-20101201.pdf, Preventive Maintenance Program
4. FP-WM-OVW-01-20100728.pdf, Work Management Process Overview
5. MNGP EWI-11 01 06.pdf, Battery Monitoring and Maintenance Program
6. Summary of mitigation plan completion and internal controls
7. MNGP PRC-005 Activities Jun 2011 to Mar 2012.xls, Monticello Nuclear Plant
8. PINGP PRC-005 Activities Jun 2011 to Mar 2012.xls, Prairie Island Nuclear Plant
9. Milestone 14 Action Completion Email, evidencing training completion
10. Milestone 15 NERC Completions, personnel training completion records
11. Milestone 15 NERC PRC-005 PPT, training content
12. Milestone 15 PRC-005 LMS Catalog
13. Nuclear PRC-005 Summary, spreadsheet of all PRC-005 program devices and the most recent two test dates for both nuclear plants
14. PINGP H37.pdf, Battery Monitoring and Maintenance Program
15. PRC-005 Communication.pdf
16. PRC-005 R2 Mitigation Plan Training

V. PENALTY INFORMATION

TOTAL ASSESSED PENALTY OR SANCTION OF **$250,000** FOR **4** VIOLATIONS OF RELIABILITY STANDARDS.

The violations identified as a result of the CVI conducted following the September 18, 2007 event occurred in the early days of mandatory applicability and enforceability of NERC Reliability Standards. In fact, the misoperation described above resulting in the violation of PRC-004-1, R1, occurred just four days after the Reliability Standards became mandatory and enforceable. The violation of COM-002-2, R2 occurred three months after the Reliability Standards became mandatory and enforceable. As such, these violations are subject to the Commission's direction in Order No. 693 that the ERO and Regional Entities would have the discretion necessary to assess penalties for serious violations during the period of June 18, 2007 through the end of 2007.

(1) REGISTERED ENTITY'S COMPLIANCE HISTORY

PRIOR VIOLATIONS OF ANY OF THE INSTANT RELIABILITY STANDARD(S) OR REQUIREMENT(S) THEREUNDER
YES ☒ NO ☐

LIST ANY CONFIRMED OR SETTLED VIOLATIONS AND STATUS

[redacted]

[redacted]

PRIOR VIOLATIONS OF OTHER RELIABILITY STANDARD(S) OR REQUIREMENTS THEREUNDER
YES ☒ NO ☐

LIST ANY PRIOR CONFIRMED OR SETTLED VIOLATIONS AND STATUS

A Notice of Penalty for a violation of CIP-001-1, R2 was filed with the Commission on June 4, 2008 in Docket No. NP08-16-000 for NSP. The Commission issued an Order on July 3, 2008, that it will not further review the Notice of Penalty, Docket No. NP08-16-000.

A Notice of Penalty for violations of VAR-001-1, R3 and R4 was filed with the Commission on May 1, 2009 in Docket No. NP09-19-000 for NSP. The Commission issued an Order on May 29, 2009, that it will not further review the Notice of Penalty, Docket No. NP09-19-000.

A Notice of Penalty for a violation of EOP-001-0, R5 was filed with the Commission on May 1, 2009 in Docket No. NP09-18-000 for NSP. The Commission issued an Order on May 29, 2009, that it will not further review the Notice of Penalty, Docket No. NP09-18-000.

ADDITIONAL COMMENTS

(2) THE DEGREE AND QUALITY OF COOPERATION BY THE REGISTERED ENTITY

FULL COOPERATION	YES	☒	NO	☐
EXEMPLARY COOPERATION	YES	☒	NO	☐

MRO considered NSP's cooperation as a mitigating factor in the penalty determination. While NSP met expectations and fully cooperated in the review and assessment of the possible violations resulting from the CVI, MRO considered NSP's cooperation with regard to the compliance audit findings to be exemplary.

As a result of the Mitigation Plan for PRC-005-1, R2 (MRO201100333), NSP provided a summary of the internal controls in effect at the time of the compliance audit, and those that were implemented as a result of the Mitigation Plan.

NSP reported that the following internal controls were in place prior to actions taken under the Mitigation Plan:

1) Standard and Requirement ownership: Each standard is assigned an organizational owner. Each standard requirement is assigned an organizational owner. In addition, individual standard owners are assigned at each site. This facilitates accountability.

2) Annual compliance roadmap update and evidence refresh: The roadmap is an internal compliance tool which provides a narrative of how compliance with a NERC standard is accomplished. It provides references to procedures, surveillance spreadsheets, and other relevant documentation and evidence. The roadmap and any associated evidence is formally reviewed and updated at least annually to ensure continued accuracy and up-to-date evidence.

3) Annual checklist completion: In preparation for annual self-certification, a review of compliance for the year is conducted, which includes spot checks of testing records. This provides confidence that adequate process controls are in place to prevent or minimize the probability of further violations of the same or similar reliability standards. Then the checklist is signed off by the requirement and standard owners. All data is then provided to the VP of Nuclear, who then reviews and attests compliance to the Authorized Entity Officer (VP of Transmission or CIO).

4) Monitoring of surveillance schedules and completion: Surveillances are flagged by computer software to be performed with an early due date, a due date, late due date, and a compliance credit date.

    a. Modification of a due date is restricted and controlled. It requires manual intervention by trained employees to enter or change these dates with appropriate procedural documentation, justification, and authorization. Surveillances may be completed within the grace period, which is the period allowed between the due date, determined by the frequency interval, and late date, which is normally 25% of the surveillance interval. Extensions up to 25% or deferrals require engineering approval. System Engineers monitor the scheduling and completion of PRC-005 maintenance and testing activities and ensure activities approaching their due date are not allowed to be deferred beyond the allowed limits.

    b. All work activities, including those now flagged as PRC-005, are monitored on a regular basis to ensure timely completion. The Work Scheduling group reviews all work activities that are approaching their due date, at least weekly. This is a

Key Performance Indicator (KPI) and is taken very seriously. Additionally, during an outage, all work activities are reviewed at least every 12 hours to ensure nothing gets missed.

NSP reported that the following internal controls were added as part of the Mitigation Plan:

1) Flag setting in PassPort on each PRC-005 device & work order: PassPort is the computer software used to track equipment inventory and to trigger work orders from scheduled Preventative Maintenance activities. The PRC-005 flagging on each component, as well as each work order that contains these components, assures that all PRC-005 protective devices are accounted for and scheduled appropriately in PassPort to ensure future test schedules are within their established interval. This flag is also visible in reports to aid in work prioritization.

2) Change Control:
   a. When a PRC-005 device is replaced, it retains the same component ID in PassPort, and therefore will retain the PRC-005 flag.
   b. New devices would be added through a capital project. An additional check has been added in the project control program which requires an assessment of PRC-005 applicability for all new equipment. Any new devices that are related to PRC-005 program would then be flagged as such in PassPort.

3) Training: Training Lesson Plan FL-MNT-FLP-001 F, NERC Procedure PRC-005 Requirement was developed to provide designated personnel the knowledge and established expectations for implementation of NERC PRC-005 standards and requirements. This training was provided to engineering, maintenance, and maintenance planning personnel who work with testing and maintaining of PRC-005 devices. The training will continue to be provided on an as needed basis to new personnel.

4) New procedure: Fleet procedure FP-MA-PRC-05, *NERC PRC-005 Protection System Maintenance and Testing Standard*, was issued on February 14, 2012, to establish the expectations for implementation of the PRC-005 related equipment under the jurisdiction and NERC reporting requirements of NSPM. It is an "umbrella" procedure which provides direction to each site on how to use existing processes and procedures to implement PRC-005. This procedure was highlighted in the Training Lesson Plan FL-MNT-FLP-001F and the formal communication that was sent on February 27, 2012.

5) Formal communication: Awareness was raised, through formal communication on February 27, 2012, with electrical maintenance and engineering personnel for recognition and application of PRC-005 requirements. This included the new Fleet procedure FP-MA-PRC-05, what PRC-005 is, why it is important, and what has/is being done to implement it.

(3) THE PRESENCE AND QUALITY OF THE REGISTERED ENTITY'S COMPLIANCE PROGRAM

IS THERE A DOCUMENTED COMPLIANCE PROGRAM
YES ☒ NO ☐

NSPM and NSPW as operating companies within the Xcel Energy Inc. holding company,[8] have a documented FERC/NERC Compliance Program. As described in its Charter of July 2, 2009, the mission of the FERC/NERC Compliance Program is two-fold:

(a) through monitoring and oversight, provide reasonable assurance that the Xcel Energy Operating Companies, Xcel Energy Services Inc. (XES), other Xcel Energy subsidiaries (e.g., WestGas Interstate), and the Xcel Energy Inc. holding company are compliant with enforceable requirements adopted by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) along with the Regional Entities to which NERC has delegated compliance enforcement responsibilities); and

(b) in coordination with internal stakeholders, promote the policy objectives of XES and the Xcel Energy Operating Companies as they relate to development and application of enforceable requirements of FERC, NERC, and the Regional Entities. Notwithstanding the foregoing, oversight of compliance with the FERC Standards of Conduct rules is not managed under the FERC/NERC Compliance Program. The Chief Compliance Officer, who is responsible for the company's Standard of Conduct Program, does have a functional reporting relationship to the FERC Compliance Officer.

EXPLAIN SENIOR MANAGEMENT'S ROLE AND INVOLVEMENT WITH RESPECT TO THE REGISTERED ENTITY'S COMPLIANCE PROGRAM, INCLUDING WHETHER SENIOR MANAGEMENT TAKES ACTIONS THAT SUPPORT THE COMPLIANCE PROGRAM, SUCH AS TRAINING, COMPLIANCE AS A FACTOR IN EMPLOYEE EVALUATIONS, OR OTHERWISE.

Xcel Energy's compliance programs fall under the general oversight of the Corporate Compliance and Business Conduct Program (CCBC). The purpose of the CCBC is to promote a culture across Xcel Energy Inc. and its subsidiaries that encourages ethical conduct and a commitment to compliance with the law. Xcel Energy Inc.'s Vice President and Corporate Secretary is the corporation's Chief Compliance Officer and has overall responsibility for the CCBC. On a periodic basis, the CCBC will review the effectiveness of each of the company's compliance programs, including the FERC/NERC Compliance Program.

Day-to-day management of the FERC/NERC Compliance Program falls under the responsibility of the Director, Compliance Monitoring and Policy with oversight from the Senior Vice President and Group President, who is also the FERC Compliance Officer.

[8] Xcel Energy Inc. is a U.S. investor-owned electricity and natural gas company with regulated operations in ten Midwestern and Western states. Based in Minneapolis, MN, Xcel Energy Inc. is a large combination natural gas and electricity company holding company, and is the corporate parent of Xcel Energy Services Inc., NSP Companies, PSCo, and SPS-XCEL. Xcel Energy Services Inc. is the service company for the Xcel Energy Inc. holding company system.

The FERC Compliance Officer is responsible for:

- fostering a culture of compliance among affected business units;
- monitoring compliance through internal audits, spot checks, investigations, or other reviews;
- coordinating activities associated with implementation of new or revised requirements;
- working with affected business units as necessary to ensure that appropriate corrective measures are implemented; and
- facilitating training as needed to support the company's FERC and NERC compliance programs.

Oversight of the FERC/NERC Compliance Program is provided by an executive-level Steering Committee. The Steering Committee sets policy for the FERC/NERC compliance program. The responsibilities of the Steering Committee are to assist the FERC Compliance officer with**:**

- monitoring and overseeing the FERC/NERC Compliance Program on be half of the Operations Council;
- setting policy direction for the enterprise-level FERC/NERC Compliance Program;
- ensuring independence in the evaluation and review of compliance matters under the direction of the enterprise-level FERC/NERC Compliance Program;
- resolving issues that may arise between FERC/NERC Compliance Program and functional business units; and
- ensuring adequate staffing and resources of the FERC/NERC Compliance Program to evaluate and monitor compliance at the functional business unit level.

The Steering Committee meets with FERC/NERC Compliance Program staff on a regular basis and as needed to address high-priority concerns. In addition, the FERC/NERC Program has access to the CEO and Board via the FERC Compliance Officer, who reports directly to the CEO.

(4) ANY ATTEMPT BY THE REGISTERED ENTITY TO CONCEAL THE VIOLATION(S) OR INFORMATION NEEDED TO REVIEW, EVALUATE OR INVESTIGATE THE VIOLATION.

YES ☐ NO ☒

(5) ANY EVIDENCE THE VIOLATION(S) WERE INTENTIONAL

YES ☐ NO ☒

(6) ANY OTHER MITIGATING FACTORS FOR CONSIDERATION

YES ☐ NO ☒

(7) ANY OTHER AGGRAVATING FACTORS FOR CONSIDERATION

YES ☐ NO ☒

The September 18, 2007 event resulted in load loss of approximately 787 MW. The violations addressed herein were not identified as initiating, causal, or contributory factors in the September 18, 2007 event. Therefore, pursuant to Commission guidance[9], MRO did not consider the loss of load as an aggravating factor in its penalty determination.

The majority of the load loss, approximately 769 MW, occurred in the service area of a neighboring entity that is not subject to FERC jurisdiction. According to the Event Analysis Report, "[t]he causal factor for the separation of the [Canadian entity's] system from the first island was the sensitive, uncoordinated settings of over-frequency protection on a range of thermal generators. Premature tripping of these units resulted in the separation of [Canadian entity] from the first island, and in significant load shedding in the [Canadian entity's] system." The Canadian entity had fitted several generators with new protection packages in 2005, with the over-frequency setting of 60.5 Hz (for 9.98 seconds) and 61.3 Hz (for 0.1 seconds). During the disturbance, two of these units were running and were tripped by over-frequency (the other units with over-frequency protection were not running). Prior to the commissioning of the new packages, the units were primarily protected by governor action, with control valves closed at 63 Hz (through normal governor action) and over-speed tripping at about 65 Hz. Subsequent to the event, the Canadian entity disabled the new over-frequency protection that caused this tripping on all of these units and reviewed setting requirements and coordination.

At the time of the event, although the Canadian entity was registered with the NERC Compliance Registry for applicable functions, there was no agreement with the applicable governmental authority to monitor and enforce compliance with the NERC Reliability Standards. Nonetheless, the Canadian entity participated in the extensive Event Analysis conducted after the event. However, because of the status of authority of MRO and NERC at the time of the event, no authority existed to conduct a compliance assessment to identify any possible violations by the Canadian entity during the event.

(8) ANY OTHER EXTENUATING CIRCUMSTANCES

YES ☐ NO ☒

There were thunderstorms in the Twin Cities-Eau Claire area on September 18, 2007. The Event Analysis determined that no lightning strokes appeared within the vicinity of the lines that tripped early in the event. The Event Analysis also determined that based on wind speeds during the time of the event, the storm did not appear to have damaging winds. The storm was not a significant factor during the event.

EXHIBITS:

1. NERC Preliminary Notice of Findings and Analysis, dated January 6, 2010

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[9] *See* Order on Review of Notice of Penalty, 134 FERC ¶ 61,209 issued March 17, 2011 and Order Denying Rehearing and Providing Clarification, 139 FERC ¶ 61,248 issued June 21, 2012 both related to a Settlement Agreement between WECC and Turlock Irrigation District.

2. NSP's response to the Preliminary Notice of Findings and Analysis, dated February 19, 2010

3. Notice of Transfer of Compliance Enforcement responsibility (NERC0001CVI), dated February 14, 2011

4. Compliance Audit Report, dated March 28, 2011

5. MROMIT007207 for MRO201100263 (COM-002-2, R2), submitted April 26, 2012
   - Certification of Mitigation Plan Completion, dated April 26, 2012

6. MROMIT007288 for MRO201100268 (PRC-004-1, R1), submitted May 4, 2012
   - Certification of Mitigation Plan Completion, dated May 8, 2012

7. MROMIT006515 for MRO201100332 (EOP-008-0, R1), submitted December 19, 2011
   - Certification of Mitigation Plan Completion, dated April 12, 2012

8. MROMIT005992 for MRO201100333 (PRC-005-1, R2), submitted October 20, 2011
   - **C**ertification of Mitigation Plan Completion, dated August 10, 2012

OTHER RELEVANT INFORMATION:

NOTICE OF ALLEGED VIOLATION AND PROPOSED PENALTY OR SANCTION ISSUED
DATE: OR N/A ☒

SETTLEMENT DISCUSSIONS COMMENCED
DATE: **8/13/2012** OR N/A ☐

NOTICE OF CONFIRMED VIOLATION ISSUED
DATE: OR N/A ☒

REGISTERED ENTITY RESPONSE CONTESTED
FINDINGS ☐ PENALTY ☐ BOTH ☐ NO CONTEST ☒

HEARING REQUESTED
YES ☐ NO ☒
DATE
OUTCOME
APPEAL REQUESTED

Attachment b

Record documents for the violation of COM-002-2 R2:

1. Northern States Power's Mitigation Plan designated as MROMIT007207 submitted April 26, 2012;
2. Northern States Power's Certification of Mitigation Plan Completion dated April 26, 2012;
3. MRO's Verification of Mitigation Plan Completion dated April 26, 2012;

Mitigation Plan

Registered Entity: Northern States Power (Xcel Energy)

NERC Violation ID	Requirement	Violation Validated On
MRO201100333	PRC-005-1 R2	08/26/2011

Mitigation Plan Submitted On: December 28, 2011
Mitigation Plan Accepted On: December 28, 2011
Mitigation Plan Proposed Completion Date: April 30, 2012
Actual Completion Date of Mitigation Plan:
Mitigation Plan Certified Complete by NSP On:
Mitigation Plan Completion Validated by MRO On:
Mitigation Plan Completed? (Yes/No): No

Section A: Compliance Notices

Section 6.2 of the NERC CMEP sets forth the information that must be included in a Mitigation Plan. The Mitigation Plan must include:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section B.
(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.
(3) The cause of the Alleged or Confirmed Violation(s).
(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).
(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed violation(s).
(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.
(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.
(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined or recommended to the applicable governmental authorities for not completing work associated with accepted milestones.
(9) Any other information deemed necessary or appropriate.
(10) The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity, which if applicable, shall be the person that signed the Self Certification or Self Reporting submittals.
(11) This submittal form may be used to provide a required Mitigation Plan for review and approval by regional entity(ies) and NERC.

• The Mitigation Plan shall be submitted to the regional entity(ies) and NERC as confidential information in accordance with Section 1500 of the NERC Rules of Procedure.

• This Mitigation Plan form may be used to address one or more related alleged or confirmed violations of one Reliability Standard. A separate mitigation plan is required to address alleged or confirmed violations with respect to each additional Reliability Standard, as applicable.

• If the Mitigation Plan is accepted by regional entity(ies) and approved by NERC, a copy of this Mitigation Plan will be provided to the Federal Energy Regulatory Commission or filed with the applicable governmental authorities for approval in Canada.

• Regional Entity(ies) or NERC may reject Mitigation Plans that they determine to be incomplete or inadequate.

• Remedial action directives also may be issued as necessary to ensure reliability of the bulk power system.

• The user has read and accepts the conditions set forth in these Compliance Notices.

Section B: Registered Entity Information

B.1 Identify your organization:

Entity Name:	Northern States Power (Xcel Energy)
NERC Compliance Registry ID:	NCR01020
Address:	414 Nicollet Mall Minneapolis MN 55401

B.2 Identify the individual in your organization who will serve as the Contact to the Regional Entity regarding this Mitigation Plan. This person shall be technically knowledgeable regarding this Mitigation Plan and authorized to respond to Regional Entity regarding this Mitigation Plan.:

Name:	Brenda Prokop
Title:	Director, Compliance Monitoring & Policy
Email:	brenda.c.prokop@xcelenergy.com
Phone:	612-330-5642

Section C: Identification of Reliability Standard Violation(s) Associated with this Mitigation Plan

C.1 This Mitigation Plan is associated with the following violation(s) of the reliability standard listed below:

Violation ID	Date of Violation	Requirement
Requirement Description		
MRO201100333	10/01/2008	PRC-005-1 R2
Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30calendar days). The documentation of the program implementation shall include:		

C.2 Identify the cause of the violation(s) identified above:

The 1N2 and 1N6 relay schemes at the Monticello Nuclear Generating Plant (MNGP) were not tested within their respective established intervals as required by established plant and fleet procedures. The cause of both violations is human error for not following procedures. The violations were discovered while responding to an MRO audit-related data request.

The 1N2 relay scheme was originally scheduled to be tested on-line in October 2006. This test was properly deferred until October 2008, but was erroneously marked as complete in another work order.

The 1N6 relay scheme was originally scheduled to be tested during the spring 2009 outage. This test was not deferred and was dropped without justification. This activity was not timely identified as incomplete or past due because there currently is no computer tracking of outage-coded Preventive Maintenance requirements that are past due.

C.3 Provide any relevant information regarding the violation(s) associated with this Mitigation Plan: [If known]

While preparing responses to MRO's audit-related data request, a gap was identified in the 1N2 relay scheme testing. Additionally, it appeared that the 1N6 relay testing had not been completed since test records or written deferrals could not be located.

Fleet Guide FG-WM-PMA-01, Preventive Maintenance and Surveillance Administration, allows for work deferral, under certain circumstances. It specifies that when a surveillance procedure (test and/or inspection) cannot be completed within the required frequency, plus grace period, because current plant conditions and/or configurations will not permit performance, or when Operations Management, Responsible Engineer or Program Owner directs deferral of a non-Technical Specification test or inspection beyond the +25% grace period for any other reason, the procedure must be evaluated and processed to 1) document that the test/inspection requirement was addressed, 2) explain why it was not performed, 3) enable PassPort to continue to generate work orders at the required frequency, and 4) to ensure proper approval and documentation are obtained. The Fleet Guide was reviewed and found to be adequate. However, application of the deferral procedure, as it relates to the 1N2 and 1N6 relay schemes, was inadequate.

Section D: Details of Proposed Mitigation Plan

D.1 Identify and describe the action plan, including specific tasks and actions that your organization is proposing to undertake, or which it undertook if this Mitigation Plan has been completed, to correct the violation(s) identified above in Section C.1 of this form:

1. The 1N6 relay scheme was tested on February 13, 2011 and was found in calibration and functional [complete];

2. The 1N2 relay scheme was verified tested on November 5, 2010 and is in compliance with the requirements of PRC-005. [complete];

3. Verify that MNGP PRC-005 related tests have been performed in accordance with the established intervals. [complete];

4. Verify that the Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2 PRC-005 related tests have been performed in accordance with the established intervals. [complete]

5. Identify and track all MNGP and PINGP PRC-005 devices due to be tested prior to January 1, 2012 to ensure timely completion of scheduled activities during mitigation action plan period. [complete];

6. Perform an additional follow-up review of nuclear site protective relay systems and validate the identified scope of components to be tracked as PRC-005 Related. Make any necessary adjustments. [complete];

7. If any devices are added to the PRC-005 program for MNPG and PINGP, verify all have been tested within their established interval, and that testing is current. [complete];

8. Complete an investigation to determine the cause of the missed tests and establish corrective actions.

   a. CAP 01267263-02 - Potential NERC PRC-005 Violation-MNGP Relay [complete].
   b. CAP 01268379 - Missed PM interval for 1N2 relay testing [complete].
   c. CAP 01287507 - PRC-005: 1R cross trip PM beyond due date [complete].

9. Develop and implement an additional code to flag PRC-005 related protection systems in the equipment data base. This flag will allow these devices to be prioritized and queried for tracking/reporting purposes.

10. Revise applicable site-specific and fleet level procedures to ensure PRC-005-1 related activities are addressed. These changes will include the following enhancements:

   a. The creation of a document that clearly ties all pieces of the existing protection system maintenance and testing program together;
   b. Require an additional level of review for the testing of PRC-005 components
   c. Increase the priority level of PRC-005 related testing and maintenance
   d. Increase the rigor of review and approval

11. Communication
   a. Issue a formal communication to the impacted maintenance, engineering and scheduling personnel to increase awareness of PRC-005-1 testing requirements;
   b. Disseminate to all electrical maintenance and engineering personnel an information package that provides additional guidance on mandatory NERC compliance;

12. Training
   a. Perform a training analysis to assess the need for additional electrical maintenance and engineering training on NERC compliance;
   b. If additional training need is identified, develop and implement a fleet lesson plan for NERC Standards applicable to electrical maintenance and engineering.

13. For all relay schemes to be tested prior to March 31, 2012, perform independent checks to ensure testing is complete prior to the required due dates.

D.2 Provide the timetable for completion of the Mitigation Plan, including the completion date by which the Mitigation Plan will be fully implemented and the violations associated with this Mitigation Plan are corrected:

Proposed Completion date of Mitigation Plan: April 30, 2012

D.3 Milestone Activities, with completion dates, that your organization is proposing for this Mitigation Plan:

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
Test 1N6 relay scheme	Test 1N6 relay scheme	02/15/2011	February 13, 2011
Verify MNGP 1N2 Relay testing is current.	Verify MNGP 1N2 Relay testing is current.	02/28/2011	February 28, 2011
Initiate an investigation to determine cause(s) for missed testing.	Create Corrective Action Program (CAP) ticket(s) to initiate investigation efforts.	04/01/2011	January 21, 2011
Verify all devices currently in the PRC-005 program for MNPG were tested within prescribed interval.	Verify all devices currently in the PRC-005 program for MNPG were tested within prescribed interval.	06/29/2011	June 27, 2011
Verify all devices currently in the PRC-005 program for PINGP were tested within prescribed interval.	Verify all devices currently in the PRC-005 program for PINGP were tested within prescribed interval.	07/01/2011	June 30, 2011
Identify all devices for PINGP and MNPG due to be tested prior to Jan. 1, 2012	Identify all devices for PINGP and MNPG due to be tested prior to Jan. 1, 2012	07/01/2011	June 29, 2011
Review list of devices in scope of PRC-005 program for MNPG and PINGP and make any necessary changes.	Review list of devices in scope of PRC-005 program for MNPG and PINGP and make any necessary changes.	07/01/2011	June 29, 2011
If any devices are added to the PRC-005 program for MNPG and PINGP, verify all have been tested within their established interva	If any devices are added to the PRC-005 program for MNPG and PINGP, verify all have been tested within their established interval.	07/01/2011	June 30, 2011
Complete an investigation to determine the cause of the subject missed tests and establish corrective actions	Complete an investigation to determine the cause of the subject missed tests and establish corrective actions	09/15/2011	September 12, 2011
Perform a Training Needs Assessment for PRC-005 Program.	Perform a Training Needs Assessment for PRC-005 Program.	11/01/2011	October 25, 2011
Develop and implement an additional code to flag PRC-005 related protection systems in the equipment data base.	Develop and implement an additional code to flag PRC-005 related protection systems in the equipment data base.	11/15/2011	November 15, 2011

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
Revise PRC-005-related program documentation	Revise PRC-005-related program documentation	02/14/2012	
Issue formal communication to impacted personnel	Issue formal communication to impacted personnel	03/01/2012	
For all relay schemes due to be tested prior to 03/31/2012, perform independent checks to ensure tested prior to each due date.	For all relay schemes due to be tested prior to 03/31/2012, perform independent checks to ensure tested prior to each due date.	03/31/2012	
Develop and Implement Fleet Training and Lesson Plan per needs Assessment.	Develop and Implement Fleet Training and Lesson Plan per needs Assessment.	03/31/2012	
Submit evidence and summary of internal controls.	Submit evidence of mitigation plan completion and summary of internal controls to MRO staff. Per MRO, internal controls include plan/process for measuring, reporting, and monitoring program performance within our company to prevent or minimize the probability of further violations of the same or similar reliability standards requirements; add statements about current/future plan, training, process, sampling and verification of schedule, actual maintenance and testing date, maintenance and testing records, etc.	04/06/2012	
Respond to data requests.	Provide additional information/ documentation, in response to MRO data requests, as part of the mitigation plan completion and validation process.	04/30/2012	

D.4 Additional Relevant Information (Optional)

Section E: Interim and Future Reliability Risk

E.1 Abatement of Interim BES Reliability Risk

While your organization is implementing the Mitigation Plan proposed in Section D of this form, the reliability of the Bulk Power System may remain at higher risk or be otherwise negatively impacted until the plan is successfully completed. To the extent they are, or may be, known or anticipated: (i) identify any such risks or impacts; and (ii) discuss any actions that your organization is planning to take or is proposing as part of the Mitigation Plan to mitigate any increased risk to the reliability of the bulk power system while the Mitigation Plan is being implemented:

We feel there is minimal risk to the BPS while this mitigation plan is being implemented, for the following reasons:
• The 1N6 and 1N2 protective relay schemes have been tested and found within their respective acceptance criteria and required no set point adjustments.
• No additional Monticello relay schemes were found to be out of their established testing interval.
• Relay schemes are due to be tested before the mitigation plan completion date of March 31, 2012. Since all of the mitigating actions will not yet be complete, an independent confirmation will be performed prior to each scheme's due date to ensure their timely completion.
• The scope of protection systems included in the PRC-005 program is being re-evaluated at both plants to ensure adequacy. If any protection systems are added to the program, we will verify they have been tested within their established interval and will immediately take any necessary mitigating actions.

E.2 Prevention of Future BES Reliability Risk

Describe how successful completion of the Mitigation Plan as laid out in Section D of this form will prevent or minimize the probability that your organization incurs further violations of the same or similar reliability standards requirements in the future:

The plan will assure that all PRC-005 protective devices are accounted for and scheduled appropriately in PassPort to ensure future test schedules are within their established interval. It will also apply another level of review for the testing of PRC-005 related components. Awareness will also be raised, through formal communication, with electrical maintenance and engineering personnel for recognition and application of PRC-005 requirements.

E.3 Your organization may be taking or planning other action, beyond that listed in the Mitigation Plan, as proposed in Section D.1, to prevent or minimize the probability of incurring further violations of the same or similar standards requirements listed in Section C.1, or of other reliability standards. If so, identify and describe any such action, including milestones and completion dates:

Section F: Authorization

An authorized individual must sign and date the signature page. By doing so, this individual, on behalf of your organization:

(a) Submits the Mitigation Plan, as laid out in Section D, to the Regional Entity for acceptance and approval by NERC, and

(b) If applicable, certifies that the Mitigation Plan, as laid out in Section D of this form, was completed (i) as laid out in Section D of this form and (ii) on or before the date provided as the 'Date of Completion of the Mitigation Plan' on this form, and

(c) Acknowledges:

1. I am VP, Engineering & Nuclear Regulatory Compliance and Licensing of Northern States Power (Xcel
2. I am qualified to sign this Mitigation Plan on behalf of Northern States Power (Xcel Energy)
3. I have read and understand Northern States Power (Xcel Energy)'s obligations to comply with Mitigation Plan requirements and ERO remedial action directives as well as ERO documents, including, but not limited to, the NERC Rules of Procedure and the NERC CMEP currently in effect or the NERC CMEP-Province of Manitoba, Schedule B currently in effect, whichever is applicable.
4. I have read and am familiar with the contents of the foregoing Mitigation Plan.
5. Northern States Power (Xcel Energy) Agrees to be bound by, and comply with, this Mitigation Plan, including the timetable completion date, as accepted by the Regional Entity, NERC, and if required, the applicable governmental authorities in Canada.

Authorized Individual Signature: ______________________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Name: Jim Molden
Title: VP, Engineering & Nuclear Regulatory Compliance and Licensing
Authorized On: December 23, 2011

Certification of Mitigation Plan Completion

Submittal of a Certification of Mitigation Plan Completion shall include data or information sufficient for the Regional Entity to verify completion of the Mitigation Plan. The Regional Entity may request additional data or information and conduct follow-up assessments, on-site or other Spot Checking, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed and the Registered Entity is in compliance with the subject Reliability Standard. (CMEP Section 6.6)

Registered Entity Name: Northern States Power (Xcel Energy)

NERC Registry ID: NCR01020

NERC Violation ID(s): MRO201100263

Mitigated Standard Requirement(s): COM-002-2 R2,

Scheduled Completion as per Accepted Mitigation Plan: June 30, 2010

Date Mitigation Plan completed: June 18, 2010

MRO Notified of Completion on Date: April 26, 2012

Entity Comment: Mitigation Plan for COM-002-2 R2 has benn completed.

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	NSP-PRO-A-002 NSP Control Center Communications.pdf	Communications Procedure	128,948
Entity	CommunicationsProtocol Xcel Energy Confidential.pdf	Training document	6,291,701
Entity	Com Training List - NSP Operators.pdf	List of operators and completion of training	21,393
Entity	Com Training List - Xcel Energy.pdf	List of all the folks who have taken the training	230,481
Entity	T053104a12.wav	Call 1	32,408
Entity	T053259a.wav	Call 2	55,960
Entity	T053516a.wav	Call 3	29,848
Entity	T054019a.wav	Call 4	27,800
Entity	COM-002-2 MP NSP Authorization.pdf	NSP Authorization for MP COM-002-2 R2	271,842

I certify that the Mitigation Plan for the above named violation(s) has been completed on the date shown above and that all submitted information is complete and correct to the best of my knowledge.

Name: Robert Thompson
Title: Senior Consultant, Transmisison Compliance
Email: robert.f.thompson@xcelenergy.com
Phone: 1 (612) 330-7968

Authorized Signature ______________________ Date ______________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Accept Mitigation Plan | Reject Mitigation Plan

Certificate of Completion Review

Completion Date Entered by Entity: 06/18/2010

Region Notified of Completion On: 04/26/2012

Certification Document (Date Received from Entity):

*Certification Reviewed By: Riaz Islam

Actual Completion Date: 06/18/2010

Resubmission by Region On Date:

Date Completion Verified by Region: 04/26/2012

Region Comment: (Visible to Entity) 0

Private Review Comment: (NOT Visible to Entity) All the system operators completed the training by 06/18/2010.

Accept Certification | Reject Certification | Request Certification Resubmission

Attachment c

Record documents for the violation of PRC-004-1 R1:

1. Northern States Power’s Mitigation Plan designated as MROMIT007288 submitted May 4, 2012;
2. Northern States Power’s Certification of Mitigation Plan Completion dated May 8, 2012 ;
3. MRO’s Verification of Mitigation Plan Completion dated May 10, 2012;

Mitigation Plan

Registered Entity: Northern States Power (Xcel Energy)

Mit Plan Code	NERC Violation ID	Requirement	Violation Validated On	Mit Plan Version
	MRO201100268	PRC-004-1 R1	05/03/2011	1

Mitigation Plan Submitted On: May 04, 2012
Mitigation Plan Accepted On: May 07, 2012
Mitigation Plan Proposed Completion Date: August 01, 2010
Actual Completion Date of Mitigation Plan:
Mitigation Plan Certified Complete by NSP On: January 01, 1900
Mitigation Plan Completion Verified by MRO On:
Mitigation Plan Completed? (Yes/No): No

Section A: Compliance Notices

Section 6.2 of the NERC CMEP sets forth the information that must be included in a Mitigation Plan. The Mitigation Plan must include:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section B.
(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.
(3) The cause of the Alleged or Confirmed Violation(s).
(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).
(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed violation(s).
(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.
(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.
(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined or recommended to the applicable governmental authorities for not completing work associated with accepted milestones.
(9) Any other information deemed necessary or appropriate.
(10) The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity, which if applicable, shall be the person that signed the Self Certification or Self Reporting submittals.
(11) This submittal form may be used to provide a required Mitigation Plan for review and approval by regional entity(ies) and NERC.

• The Mitigation Plan shall be submitted to the regional entity(ies) and NERC as confidential information in accordance with Section 1500 of the NERC Rules of Procedure.

• This Mitigation Plan form may be used to address one or more related alleged or confirmed violations of one Reliability Standard. A separate mitigation plan is required to address alleged or confirmed violations with respect to each additional Reliability Standard, as applicable.

• If the Mitigation Plan is accepted by regional entity(ies) and approved by NERC, a copy of this Mitigation Plan will be provided to the Federal Energy Regulatory Commission or filed with the applicable governmental authorities for approval in Canada.

• Regional Entity(ies) or NERC may reject Mitigation Plans that they determine to be incomplete or inadequate.

• Remedial action directives also may be issued as necessary to ensure reliability of the bulk power system.

• The user has read and accepts the conditions set forth in these Compliance Notices.

Section B: Registered Entity Information

B.1 Identify your organization:

Entity Name: Northern States Power (Xcel Energy)

NERC Compliance Registry ID: NCR01020

Address: 414 Nicollet Mall
Minneapolis MN 55401

B.2 Identify the individual in your organization who will serve as the Contact to the Regional Entity regarding this Mitigation Plan. This person shall be technically knowledgeable regarding this Mitigation Plan and authorized to respond to Regional Entity regarding this Mitigation Plan:

Name: Robert Thompson

Title: Senior Consultant, Transmission Compliance

Email: robert.f.thompson@xcelenergy.com

Phone: 612-330-7968

Section C: Identification of Reliability Standard Violation(s) Associated with this Mitigation Plan

C.1 This Mitigation Plan is associated with the following violation(s) of the reliability standard listed below:

Violation ID	Date of Violation	Requirement
Requirement Description		
MRO201100268	06/18/2007	PRC-004-1 R1
The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.		

C.2 Brief summary including the cause of the violation(s) and mechanism in which it was identified above:

NSP had developed a Corrective Action Plan for the June 22, 2007 Coon Creek (CNC) – Terminal (TER) 345 kV line misoperation that included a list of maintenance activities intended to prevent recurrence of the misoperation. These maintenance activities were specified in a Work Request that triggered issuance of three Work Orders. NSP has no documentation to establish that the Work Orders were completed within the timeframe intended by NSP. As soon as NSP discovered that the Work Orders had been closed without recording any time or details about work completed, NSP issued a new Work Request and associated Work Orders and the work was completed on March 20, 2009.

C.3 Provide any relevant information regarding the identification of the violation(s) associated with this Mitigation Plan:

During its February, 2009 site visit, the NERC CVI team requested documentation establishing completion of the actions identified in the Corrective Action Plan for the Coon Creek–Terminal 345 kV line. In the process of compiling information on the Work Orders generated pursuant to the Work Request issued under the Corrective Action Plan, NSP noticed that no time had been charged to the Work Orders. NSP decided to investigate further, and NSP ultimately concluded that it could not affirmatively represent to NERC that the required work had been performed. At that point, NSP notified the NERC on-site team that the Corrective Action Plan had not yet been completed.

Section D: Details of Proposed Mitigation Plan

D.1 Identify and describe the action plan, including specific tasks and actions that your organization is proposing to undertake, or which it undertook if this Mitigation Plan has been completed, to correct the violation(s) identified above in Section C.1 of this form:

(1) Complete the corrective action plan identified for the misoperation of the Coon Creek-Terminal line.
(2) Reorganize to create a new System Protection Engineering area responsible for management of the misoperation analysis and corrective action process.
(3) Review and revise the Xcel Energy misoperation process/procedure.

Step 1 was completed on 3/20/2009.
Re-issue and complete work orders to implement the corrective action plan. Work orders are:
(1) WO 11213131 Test Terminal (TER) 345 kV line relays at Kohlman Lake (KOL)
(2) WO 11213132 Test Kohlman Lake (KOL) 345 kV line relays at Terminal (TER) Substation
(3) WO 11213133 Check Chisago 345 KV line CTs at Kohlman Lake (KOL) Substation

D.2 Provide the timetable for completion of the Mitigation Plan, including the completion date by which the Mitigation Plan will be fully implemented and the violations associated with this Mitigation Plan are corrected:

Proposed Completion date of Mitigation Plan: August 01, 2010

D.3 Milestone Activities, with completion dates, that your organization is proposing for this Mitigation Plan:

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
Reorganize and assign the responsibility for mis-operations to the new System Protection Engineering area.	Xcel Energy Transmission reorganized its protection expertise into the System Protection Engineering group. This new group provides additional focus on protection systems, misoperation analysis, and corrective action plan development and management.	06/01/2010	06/01/2010
Review and revise the Mis-operation process/procedure.	The misoperation process has been modified to include a weekly open item checklist for engineers and field personnel. In addition, a monthly conference call has been instituted to review all open investigations and Corrective Action Plans with engineering and field technicians. The monthly conference call involves discussion of field activities and findings associated with misoperations.	08/01/2010	07/01/2010

D.4 Additional Relevant Information (Optional)

Section E: Interim and Future Reliability Risk

E.1 Abatement of Interim BPS Reliability Risk

While your organization is implementing the Mitigation Plan proposed in Section D of this form, the reliability of the Bulk Power System may remain at higher risk or be otherwise negatively impacted until the plan is successfully completed. To the extent they are, or may be, known or anticipated: (i) identify any such risks or impacts; and (ii) discuss any actions that your organization is planning to take or is proposing as part of the Mitigation Plan to mitigate any increased risk to the reliability of the bulk power system while the Mitigation Plan is being implemented:

The corrective action plan for the Coon Creek to Terminal line misoperation was completed on March 20, 2009.

NSP had developed a Corrective Action Plan for the June 22, 2007 Coon Creek (CNC) – Terminal (TER) 345 kV line misoperation that included a list of maintenance activities intended to prevent recurrence of the misoperation. These maintenance activities were specified in a Work Request that triggered issuance of three Work Orders. NSP found no documentation to establish that the Work Orders were completed within the timeframe intended by NSP, however. As soon as NSP discovered that the Work Orders had been closed without recording any time or details about work completed, NSP issued a new Work Request and associated Work Orders and the work was completed on March 20, 2009.

NSP notes that the delay in completion of the Corrective Action Plan did not result in any harm to the bulk power system, as the relay did not Misoperate between the time that the Work Orders were initially issued and the subsequent Works Orders actually completed.

E.2 Prevention of Future BPS Reliability Risk

Describe how successful completion of the Mitigation Plan as laid out in Section D of this form will prevent or minimize the probability that your organization incurs further violations of the same or similar reliability standards requirements in the future:

The new System Protection Engineering group is staffed with Protection Engineers and provides a more specific focus on System Protection issues, including misoperation analysis and corrective action plan development and implementation. This group provides concentrated knowledge for event analysis and other protection system related compliance efforts. In addition, weekly progress reviews of Corrective Action Plans helps ensure that required work is completed. The monthly conference call to discuss investigations and Corrective Action Plans assists in tracking and completing the plans in a timely manner.

E.3 Your organization may be taking or planning other action, beyond that listed in the Mitigation Plan, as proposed in Section D.1, to prevent or minimize the probability of incurring further violations of the same or similar standards requirements listed in Section C.1, or of other reliability standards. If so, identify and describe any such action, including milestones and completion dates:

See above.

Section F: Authorization

An authorized individual must sign and date the signature page. By doing so, this individual, on behalf of your organization:

(a) Submits the Mitigation Plan, as laid out in Section D, to the Regional Entity for acceptance and approval by NERC, and

(b) If applicable, certifies that the Mitigation Plan, as laid out in Section D of this form, was completed (i) as laid out in Section D of this form and (ii) on or before the date provided as the 'Date of Completion of the Mitigation Plan' on this form, and

(c) Acknowledges:

1. I am Vice President - Transmission of Northern States Power (Xcel Energy)
2. I am qualified to sign this Mitigation Plan on behalf of Northern States Power (Xcel Energy)
3. I have read and understand Northern States Power (Xcel Energy)'s obligations to comply with Mitigation Plan requirements and ERO remedial action directives as well as ERO documents, including, but not limited to, the NERC Rules of Procedure and the NERC CMEP currently in effect or the NERC CMEP-Province of Manitoba, Schedule B currently in effect, whichever is applicable.
4. I have read and am familiar with the contents of the foregoing Mitigation Plan.
5. Northern States Power (Xcel Energy) Agrees to be bound by, and comply with, this Mitigation Plan, including the timetable completion date, as accepted by the Regional Entity, NERC, and if required, the applicable governmental authorities in Canada.

Authorized Individual Signature: ______________________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Authorized Individual

Name: Teresa Mogensen

Title: Vice President - Transmission

Authorized On: May 04, 2012

Certification of Mitigation Plan Completion

Submittal of a Certification of Mitigation Plan Completion shall include data or information sufficient for the Regional Entity to verify completion of the Mitigation Plan. The Regional Entity may request additional data or information and conduct follow-up assessments, on-site or other Spot Checking, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed and the Registered Entity is in compliance with the subject Reliability Standard. (CMEP Section 6.6)

Registered Entity Name: Northern States Power (Xcel Energy)

NERC Registry ID: NCR01020

NERC Violation ID(s): MRO201100268

Mitigated Standard Requirement(s): PRC-004-1 R1,

Scheduled Completion as per Accepted Mitigation Plan: August 01, 2010

Date Mitigation Plan completed: July 01, 2010

MRO Notified of Completion on Date: May 08, 2012

Entity Comment: Mitigaiton Plan was completed in 2010.

Additional Documents

From	Document Name	Description	Size in Bytes
Entity	XES-17 Work Orders for Coon Creek -Terminal.pdf	Work order document showing completion of corrective action plan.	581,296
Entity	XEL-PRO-TransmProtectSystMisOpInvestProcessMap.pdf	Misoperation process map	40,386
Entity	XEL-PRO-TransmProtSysMisOpProcedure.pdf	Misoperation procedure	57,672
Entity	OrgChart SPE Group 4-5-2012.pdf	Current System Protection Engineering organization chart (as of 4/5/2012).	138,776
Entity	NSP MisOp Meeting Notices Feb-Mar 2012.doc	Completion - February and March 2012 meeting notices	173,056
Entity	Misoperation Tracking NSP_Feb_28_Meeting-BES.xls	Completion - February 2012 MisOp Meeting BES	20,992
Entity	Misoperation Tracking NSP_Mar_27_Meeting-BES.xls	Completion - March 2012 MisOp Meeting BES	22,016
Entity	NSP MP PRC-004-1 Authorization 5-4-2012.pdf	MP Authorization	2,408,145

I certify that the Mitigation Plan for the above named violation(s) has been completed on the date shown above and that all submitted information is complete and correct to the best of my knowledge.

Name: Robert Thompson

Title: Senior Consultant, Transmission Compliance
Email: robert.f.thompson@xcelenergy.com
Phone: 1 (612) 330-7968

Authorized Signature ______________________________ Date ______________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

From: noreply@oati.net
Sent: Thursday, May 10, 2012 11:25 AM
To: cdms-mpstatus@midwestreliability.org
Subject: [cdms-mpstatus] A Mitigation Plan has been verified as completed for Entity: Northern States Power (Xcel Energy) - Violation#MRO201100268

Please do not REPLY to this message. It was sent from an unattended mailbox and replies are not monitored.

The following Mitigation Plan has been verified as completed by MRO.

Entity: ***Northern States Power (Xcel Energy) - NCR01020***
*NERC Violation ID:****MRO201100268***
Standard Requirement: ***PRC-004-1 R1***
Mitigation Plan submitted on: ***05/04/2012*** *(Version* ***1****), for Program Year:* ***2011***
Proposed Completion Date: ***08/01/2010***
Actual Completion Date: ***07/01/2010***
MRO Verified Completion Date on: ***05/10/2012***
If you have any questions regarding this notification, please contact:mitigation@midwestreliability.org.

Note: This is a webCDMS application generated message. Please Do NOT respond to this email.

[OATI Information - Email Template: MitPlan_Completed]

Attachment d

Record documents for the violations of EOP-008-0 R1.5 and PRC-005-1 R2.1:

1. Northern States Power's Compliance Audit Worksheet;
2. Northern States Power's Mitigation Plan designated as MROMIT006515 submitted December 19, 2011;
3. Northern States Power's Certification of Mitigation Plan Completion dated April 12, 2012;
4. MRO's Verification of Mitigation Plan Completion dated April 13, 2012;
5. Northern States Power's Mitigation Plan designated as MROMIT005992 submitted October 20, 2011;
6. Northern States Power's Certification of Mitigation Plan Completion dated August 10, 2012; and
7. MRO's Verification of Mitigation Plan Completion dated August 10, 2012.

FOR PUBLIC RELEASE - JULY 31, 2013

Compliance Audit Worksheet - 2011
Northern States Power (Xcel Energy)

Audit Type: 3 Year Audit
Conducted On: February 14, 2011

Lead Auditor: Will Smith
Phone No: 655-855-1718 **Email:** ws.smith@midwestreliability.org

Entity: Northern States Power (Xcel Energy)
Address: 414 Nicollet Mall, Minneapolis, MN 55401
NERC Registry ID: NCR01020

Standard Requirement	Finding	Auditor Summary Notes and Additional Information (if any ...)
EOP-008-0 R1	Possible Violation	Midwest ISO became the Balancing Authority for NSP January 6, 2009. The Coordinated Functional Registration, JRO00001, identifies the Midwest ISO as the responsible member for R1.2 and identifies NSP as the responsible member for all the other sub-requirements for the BA function. NSP has control centers in Minneapolis and Eau Claire (Skypark) and commercial operations in Denver. R1.1 NSP has three sets of EMS Servers. The primary and secondary EMS servers are located in the Minneapolis control center. The Minneapolis site provides EMS service for the entire NSP footprint for all NSP control centers. The primary EMS servers will failover to the secondary EMS servers. The third set of EMS servers, is located at the NSP facility in Eau Claire, Wisconsin (Skypark). These back-up EMS servers at Skypark can also be activated to control the entire NSP footprint. For loss of telecommunications, NSP has several alternatives available to maintain control center functionality for data and voice communications. For example, if the Public Switched Telephone Network fails, it can be replaced with the MSAT Satellite Phone. Alternatives for voice communication include: • Public Switched Telephone Network • Government Emergency Telecommunications Service • Wireless Priority Service • MSAT Satellite Phone • MISO Communication System (messaging system) • Mission Mode Communication System The voice and data for communications for the NSP Minneapolis and Skypark control centers use SONET ring technology. RTU data directed to both control centers. R1.2 Per the Coordinated Functional Registration, MISO is responsible for providing basic tie line control and maintaining the status of all inter-area schedules. R1.3 NSP's Contingency Plan provides for the back-up EMS or back-up Control Center to provide the monitoring of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. For Time error correction and regulation the MISO is responsible for providing Time error correction and Regulation according to the Coordinated Functional Registration. R1.4 NSP maintains voice communications with other areas are maintained through multiple layers of redundant communication technology as identified in the documents below. The general plan for loss of voice communications is contained in the following document: "NSP-PRO-Loss of CC-Control Room Communications including Telecommunications (v9).doc". This document identifies the recovery steps for each type of communication. The System Operators play a key role in diagnosing the source of the loss and activating the backup tools to maintain communication. • Loss of single phone: See Section 2, page 3 • Loss of multiple phones: See Section 2, page 3 • Loss of satellite-based communications: See Section 3, page 5 • Loss of Internet: See Section 4, page 5 • Loss of Midwest Communication System (MCS): See Section 6, page 6 R1.5 Testing of Back-up Control Center procedures occurs in two ways. There are routine tests of the back-up EMS that occur daily; and there are asset recovery tests that occur at least annually. NSP's “Back-up Control Center Validation”, verifies correct operation of the Backup Energy Management System (BEMS) as measured by the requirements of the Transmission department of NSP. The BEMS resides in Eau Claire, Wisconsin, at the NSP Sky Park facility, and is the backup to the primary and secondary EMS systems in Minneapolis, Minnesota. The validation plan includes procedures and responsibilities to conduct the annual test.

FOR PUBLIC RELEASE - JULY 31, 2013

Standard Requirement	Finding	Auditor Summary Notes and Additional Information (if any ...)
EOP-008-0 R1 (Continued)	Possible Violation	The night shift Network Reliability Leader (NRL) at the Minneapolis Control Center performs a daily back-up EMS test procedure. These occur Monday through Friday morning before 0500 to validate the Backup EMS (BEMS) is functional and available. R1.6 The Transmission Control Center Manager is responsible for arranging the annual training for operating personnel to implement the contingency plans. Annual training for operators includes the implementation of the contingency plans. NSP has a training course in their LMS: T8532P-088 NSP Control Center Evacuation and Backup EMS Activation. R1.7 The set of documents that constitute the “Loss of Control Center Functionality” are reviewed and updated annually. These documents address Voice Communications, Loss of EMS Functionality, Back-up EMS and Evacuation, and Critical Cyber Asset Recovery. The Back-up Control Center Validation Plan is reviewed annually by the Managers of EMS Application Delivery and the Transmission Control Center. After each test, a debrief session is held to review the plan. The objective of this plan is to annually verify the complete and correct operation of the Backup Energy Management System (EMS) as measured by the requirements of the Transmission department of Xcel Energy. R1.8 The cutover to the Back-up Control Center can be managed from either site. Telephone communications are available at both sites. Communication cut-over occurs using the Qwest transfer procedure which is expected to occur within 5 minutes. The EMS cutover is expected to occur within 15 minutes. The Operators at the alternate site would then commence monitoring the evacuating control center’s transmission system until the personnel from the evacuating site arrive (in approximately 90 minutes). Possible Violation: R1.5 The Skypark Control Center, as a TOP, plan does not include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan. The SME was asked what functions were provided by the Skypark Control Center, switching of elements 100kV and above is conducted at the Skypark Control Center. The Minneapolis NRL is not required to approve switching prior to taking place and NSP has provided the Transmission System Operator the authority switch as needed to operate the Wisconsin system. The SMEs were questioned at the Skypark Control Center and during SME interviews in Minneapolis. During both interviews the SMEs stated they had not tested the plan for loss of control center functionality at the Skypark facility. The SMEs stated the Minneapolis Control Center has one console running which has the categories selected for the Wisconsin system. However, the evacuation to Western Ave and testing of the facility and the possible deployment to Minneapolis has not been tested. Supporting documents: NSP-EXT-NERC Standards Applicability List for CFR.pdf NSP-PLN-Loss of Control Center Functionality Overview NSP-PLN-NSP_Emergency_Operation_Procedure (v7.1).doc NSP-EVD-Backup Control Center Annual Review_May 18, 2010.doc NSP-EVD-Back-up Control Center Validation_Plan.doc NSP-EVD-Back-up Control Center Validation Results_11_16_2010.doc NSP-EVD-Back-up Control Center Validation Results_05_18_2010.doc NSP-EVD-Back-up Control Center Validation Results_02_16_2010.pdf NSP-PRO-A-007 Daily Back-up EMS test procedure.doc NSP-EVD-TCC Operator’s Log - Back-up EMS tests.doc NSP-PLN-Loss of CC-List of Major Facilities to be Monitored if EMS Fails (v9).doc NSP-PRO-Loss of CC-Control Room Communications including Telecommunications (v9).doc NSP-EVD-NSP SONET System-1.pdf NSP-EVD-NSP SONET System-2.vsd XEL-PLN-Control Center CCA Recovery Plan (v3).doc NSP-EVD-2008 BEMS Test Debriefing Discussion and Assignments.msg NSP-PLN-Loss of CC-Minneapolis System Control Center Evacuation to Skypark-Wisconsin (v9).doc NSP-PLN-Loss of CC-Skypark Wisconsin System Control Center Evacuation (v9).doc NSP-PLN-5.1 Minneapolis System Control Center Evacuation to Chestnut (v8.1).doc NSP-PRO-Loss of CC-BEMS Activation Procedure.doc NSP-PLN-Loss of CC-Loss of Energy Management System (v9.1).doc NSP-PLN-Loss of CC-Loss of Frequency Reference Device - Loss of EMS Freq Reading (v9.0).doc NSP-PLN-Loss of CC-Security Analysis Monitoring through the Reliability Coordinator (v9).doc NSP-PRO-A-025 ICCP, Telemetering, Control Equipment and Communication Outages (v1.1).doc XEL-PLN-Documentation Maintenance and Management.doc NSP-PLN-0.0 EOP TABLE OF CONTENTS 2010.doc NSP-EVD-XCEL_001_T8532P-088 ILA r1.doc T8532P-088 CC Evac and B-up 2010.xls NSP-POL- P-019 Continuing Training (1.2).doc 2009-2010 Control Center Evacuation Training.doc XEL-PLN-Control Center CCA Recovery Plan (v3).doc NSP-PRO-Loss of CC-Control Room Communications including Telecommunications (v9).doc NSP-PRO-A-019 Mission Mode Communication System (v2.2).doc NSP-PRO-A-028 Government Emergency Telecommunications Service(v1.3).doc NSP-PRO-A-029 Wireless Priority Service (v1.2).doc NSP-PRO-A-036 MSAT PHONE INSTRUCTIONS.doc NSP-PLN-Loss of CC-Loss of Energy Management System (v9.1).doc NSP-PLN-Loss of CC-Loss of Frequency Reference Device - Loss of EMS Freq Reading (v9.0).doc NSP-PLN-Loss of CC-Security Analysis Monitoring through the Reliability Coordinator (v9).doc NSP-PRO-A-025 ICCP, Telemetering, Control Equipment and Communication Outages (v1.1).doc AGC-GEN Calculation Spreadsheet.xls

FOR PUBLIC RELEASE - JULY 31, 2013

Standard Requirem	Finding	Auditor Summary Notes and Additional Information (if any ...)
EOP-008-0 R1 (Continued)	Possible Violation	XCEL EmergencyBuildingProcedures rev.19_01.2009 .pdf XEL-EVD-Generation and Balancing Operations Interface.doc OP-38 Data Reqeust Response.doc - Commercial Operations relationship bems-112409 (annotated).xls
PRC-005-1 R2	Possible Violation	NSP has not received a requested by the RRO since the last audit (February 2008). MRO conducted a spot check in the fall of 2009 on PRC-005-1 for NSP's Forbes substation. The data was submitted within the requested time frame. MRO document NSP_spot check letter.pdf is included and lists NSP as compliant with PRC-005-1 as it relates to the spot check. NSP Transmission utilizes the Passport (work management) System to track maintenance intervals of protection system devices. All BES batteries are tested on an annual basis utilizing inter-cell resistance testing methods. Batteries are classified as either L1 (level 1, no monitoring) or L2 (level 2, monitored by alarms sent to a staffed control room). Batteries that are classified as L1 require quarterly voltage checks. For non-nuclear plant battery systems, establishes the requirements for the plants to maintain copies of maintenance procedure data sheets in the plant maintenance record files for 3 years for monthly and quarterly battery inspections; for 5 years for annual battery inspections; and for 3 years or the life of the battery, whichever is longer, for battery capacity test results. The datasheets identify the date that the battery maintenance was performed. These data sheets are scanned and stored electronically. Plants are required to maintain records for the last three maintenance intervals , for non-nuclear plant protective relays, control circuits and potential and current sensing devices. This data includes the date that maintenance was performed. These records are maintained on individual Excel spreadsheets for each relay and for each set of current and potential sensing devices. These files are named to clearly identify plant site, unit, protective scheme, and protective function. For ease of accessibility, the data is stored in a write protected centralized file and utilizes a folder structure organized by plant site, unit, and protective scheme. There are no records of maintenance on communication systems because communication systems are not used in the NSP non-nuclear Generator Protection Systems. Maintenance of non-nuclear plant protection systems is scheduled and performed on a scheme or Protection System basis rather than at the individual device level. NSP the Generator Owner (Nuclear) Self on PRC-005 R2 on January 31, 2011 during the compliance audit documentation review for the Relays at the Monticello Generation Station. Because Protection System Maintenace and Testing program is design. Whereas, the maintenance and testing for the DC Control Circuitry is perform at the same time as the relay testing, this self report would also include failure to test there DC Control Circuitry. XEL_TO_NSP Device List.xls XEL_TO_NSP Batteries.xls RFI_OP_21_REQUESTED_DEVICES.xls RFI_OP_21_REQUESTED_TEST_DATA.pdf RFI OP-22 Relay - Gen.xls Inver Hills 3 Gen.zip Riverside 9 Gen.zip Sherburne County 3 - 3 Gen.zip Sherburne County 3 - 31 MSA.zip Sherburne County 3 - 31 RSA.zip Sherburne County 3 - 32 MSA.zip Sherburne County 3 - 32 RSA.zip Sherburne County 3 - Battery Test Data.zip Sherburne County 3 – Bus 303.zip Sherburne County 3 – Bus 306.zip SHC2MBAT3773588 05-06-2010.pdf 5/6/2010 SHC2QBAT4051905 11-16-2010.pdf 11/16/2010 SHC2ABAT3378716 10-22-2009.pdf 10/22/2009 SHC2CBAT3148254 12-05-2009.pdf 12/5/2009 SH2RG2-59G2.xls 3/8/2010 SH2RG2-CT-87G2-line.xls 3/5/2010 SH2RG2-PT-meters.xls 3/3/2010 Non-nuclear Generator Battery Test Status -Nov2010.xls 12/20/2010 Non-Nuclear Generator Protection System Test Status - Nov 2010.xls 12/20/2010 EPR-5.704S, Battery Maintenance Standard (v1.6).doc 1/26/2010 EPR-5.714S, Protective Relay Maintenance Standard (v2.2).doc 7/21/2010 RFI OP-22 Relay - Gen.xls Monticello Gen.zip MNGP PRC-005 Gen Trans PT CT.xls PINGP PRC-005 Gen & Trans.xls PINGP PRC-005 Substation Batteries.xls MNGP PRC-005 Gen Trans PT CT.xls MNGP PRC-005 Trans Sone Protection.xls RFI-OP-22 rev2.xls

Standard Requirement	Finding	Auditor Summary Notes and Additional Information (if any ...)
PRC-005-1 R2 (Continued)	Possible Violation	History of analysis which led to MRO's determination that Granite City qualifies as a BES plant: During NSP's initial NERC classification of the NSP generating units, Granite City was not included as a Bulk Electric System plant. The Granite City generators connect to a distribution bus between the low side of a 13.8kV/115kV step-down distribution transformer and a transformer low side breaker. Thus, NSP considered it connected at a voltage of 13.8kV, well below 100kV. Typical operation is with the generators shut down and distribution load fed from the transmission system via the 13.8kV/115kV step down transformer. Because of the above configuration and normal mode of operation, Granite City was not categorized as a BES plant. In 2009, questions arose around the decision to not classify Granite City as a BES plant. After some internal analysis and discussion, a formal request was made to MRO for their interpretation on March 18, 2010. In that letter, NSP explained why it felt the plant was not a BES facility, based on a combined read of the NERC definition of Bulk Electric System and the NERC Statement of Compliance Registry Criteria. MRO requested some additional data in June 2010, to aid them in their consideration of the facts. Apparently sometime in the late summer or early fall of 2010, MRO informally notified NSP of their decision. It is unclear when that occurred due to personnel changes and lack of documentation. On April 15, 2011, staff from MRO communicated that they had determined the Granite City units do qualify as BES units. A review of all NERC requirements has been conducted and Granite City has evidence of compliance for all applicable requirements except battery testing for the period of June 2007- May 2008, as explained below. Detail explanation of subsequent potential non-compliance: Based on NSP's initial classification of the plant, Granite City was not required to follow the internal policies designed to meet the requirements of PRC-005, which required performance of battery and relay maintenance on protection systems that affect the reliability of the Bulk Electric System. Specifically, these policies are EPR 5.704S Battery Maintenance Standard (monthly, quarterly, and annual maintenance, and capacity testing) and the relay maintenance described in EPR 5.714S Protective Relay Maintenance Standard (set maintenance intervals based on relay type and duty). Although not required, Granite City did adopt the protection system maintenance program as good maintenance practice and initiated battery maintenance in June 2008. Based on MRO's determination that Granite City is a BES plant, several internal policies became mandatory for Granite City in order to comply with applicable Generator Owner and Generator Operator requirements. This includes the battery maintenance policy EPR 5.704S. When applied retro-actively to June 18, 2007, it was determined that battery maintenance had not been conducted for the period of June 2007 through May 2008. This equates to twelve monthly, four quarterly, and one annual battery maintenance performance.

Mitigation Plan

Registered Entity: Northern States Power (Xcel Energy)

NERC Violation ID	Requirement	Violation Validated On
MRO201100332	EOP-008-0 R1	08/26/2011

Mitigation Plan Submitted On: December 19, 2011
Mitigation Plan Accepted On: December 22, 2011
Mitigation Plan Proposed Completion Date: April 30, 2012
Actual Completion Date of Mitigation Plan:
Mitigation Plan Certified Complete by NSP On:
Mitigation Plan Completion Validated by MRO On:
Mitigation Plan Completed? (Yes/No): No

Section A: Compliance Notices

Section 6.2 of the NERC CMEP sets forth the information that must be included in a Mitigation Plan. The Mitigation Plan must include:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section B.
(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.
(3) The cause of the Alleged or Confirmed Violation(s).
(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).
(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed violation(s).
(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.
(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.
(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined or recommended to the applicable governmental authorities for not completing work associated with accepted milestones.
(9) Any other information deemed necessary or appropriate.
(10) The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity, which if applicable, shall be the person that signed the Self Certification or Self Reporting submittals.
(11) This submittal form may be used to provide a required Mitigation Plan for review and approval by regional entity(ies) and NERC.

• The Mitigation Plan shall be submitted to the regional entity(ies) and NERC as confidential information in accordance with Section 1500 of the NERC Rules of Procedure.

• This Mitigation Plan form may be used to address one or more related alleged or confirmed violations of one Reliability Standard. A separate mitigation plan is required to address alleged or confirmed violations with respect to each additional Reliability Standard, as applicable.

• If the Mitigation Plan is accepted by regional entity(ies) and approved by NERC, a copy of this Mitigation Plan will be provided to the Federal Energy Regulatory Commission or filed with the applicable governmental authorities for approval in Canada.

• Regional Entity(ies) or NERC may reject Mitigation Plans that they determine to be incomplete or inadequate.

• Remedial action directives also may be issued as necessary to ensure reliability of the bulk power system.

• The user has read and accepts the conditions set forth in these Compliance Notices.

Section B: Registered Entity Information

B.1 Identify your organization:

Entity Name: Northern States Power (Xcel Energy)
NERC Compliance Registry ID: NCR01020
Address: 414 Nicollet Mall
Minneapolis MN 55401

B.2 Identify the individual in your organization who will serve as the Contact to the Regional Entity regarding this Mitigation Plan. This person shall be technically knowledgeable regarding this Mitigation Plan and authorized to respond to Regional Entity regarding this Mitigation Plan.:

Name: Bob Thompson
Title: Senior Consultant Transmission Policy and Compliance
Email: robert.f.thompson@xcelenergy.com
Phone: 612-330-7968

Section C: Identification of Reliability Standard Violation(s) Associated with this Mitigation Plan

C.1 This Mitigation Plan is associated with the following violation(s) of the reliability standard listed below:

Violation ID	Date of Violation	Requirement
Requirement Description		
MRO201100332	02/28/2008	EOP-008-0 R1
Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:		

C.2 Identify the cause of the violation(s) identified above:

Northern States Power (NSP) has two control centers: the NSP-MN Transmission Control Center in Minneapolis, MN; and the NSP-WI Transmission Control Center in Eau Claire, WI. The NSP-WI Transmission Control Center evacuation plan was not fully tested and documented on an annual basis as required by EOP-008 Requirement 1.5. This potential violation was found during the February 2011 MRO Compliance Audit of NSP.

C.3 Provide any relevant information regarding the violation(s) associated with this Mitigation Plan: [If known]

The violation was identified during the interview of the subject matter experts in the compliance audit.

While there was not a documented test of the NSP-WI Transmission Control Center evacuation plan, a number of the steps in the plan are routinely tested through NSP's normal business practices, as discussed in more detail below.

Because both Transmission Control Centers operate from the primary EMS system in MInneapolis, MN, in the event of evacuation of the NSP-WI Transmission Control Center, the operation of the primary EMS system in Minneapolis would be unaffected. The NSP-MN Transmission Control Center has a terminal with all of the NSP-WI authorities already set up in it. Each weekday morning, the NSP-MN Transmission Control Center operators log into this terminal and verify that it is operational. Therefore, every weekday, NSP verifies that the NSP-MN Transmission Control Center can monitor the NSP-WI system.

The plan for evacuation of the NSP-WI Transmission Control Center therefore consists of informing management; contacting the NSP-MN Transmission Control Center to request that NSP-MN assume control of the NSP-WI system; printing out the status of several 69 kV capacitor banks; logging out of the EMS terminal at the NSP-WI Transmission Control Center; NSP-MN issuing a Mission Mode alert, assuring communication ability via emergency cell phone; and reassembling the NSP-WI Transmission Control Center personnel at the Xcel Energy Western Avenue facility in Eau Claire, the designated gathering point.

NSP addressed the condition identified during the audit promptly. The NSP-WI Transmission Control Center evacuation plan was successfully tested and documented on February 23, 2011.

Section D: Details of Proposed Mitigation Plan

D.1 Identify and describe the action plan, including specific tasks and actions that your organization is proposing to undertake, or which it undertook if this Mitigation Plan has been completed, to correct the violation(s) identified above in Section C.1 of this form:

There are three tasks identified in this mitigation plan.
1. Create an overall test plan that describes the procedures and responsibilities for conducting periodic tests, at least annually, for loss of a primary control center.
2. Conduct a post-test review of the Loss of Control Center exercise and document and incorporate any improvements or changes that were identified.
3. Perform a comprehensive review all of the requirements of EOP-008 to identify any additional needed actions, and complete identified actions.

D.2 Provide the timetable for completion of the Mitigation Plan, including the completion date by which the Mitigation Plan will be fully implemented and the violations associated with this Mitigation Plan are corrected:

Proposed Completion date of Mitigation Plan: April 30, 2012

D.3 Milestone Activities, with completion dates, that your organization is proposing for this Mitigation Plan:

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
1 Finalize Test Plan	Finalize Loss of Control Center Test Plan	11/30/2011	November 10, 2011
2 Conduct post-test review	Conduct post-test review of the Loss of Control Center Test Plan and update if needed.	01/06/2012	
3 Review all EOP-008 Requirements	Comprehensive review of all EOP-008 requirements, and completion of any follow-up actions.	03/31/2012	
Verification and completion	NSP to provide MRO the completion data for this mitigation plan.	04/30/2012	

D.4 Additional Relevant Information (Optional)

Section E: Interim and Future Reliability Risk

E.1 Abatement of Interim BES Reliability Risk

While your organization is implementing the Mitigation Plan proposed in Section D of this form, the reliability of the Bulk Power System may remain at higher risk or be otherwise negatively impacted until the plan is successfully completed. To the extent they are, or may be, known or anticipated: (i) identify any such risks or impacts; and (ii) discuss any actions that your organization is planning to take or is proposing as part of the Mitigation Plan to mitigate any increased risk to the reliability of the bulk power system while the Mitigation Plan is being implemented:

During the implementation phase, there are no known reliability risks, as the annual test for the Loss of Control Center Test Plan was completed on 2/23/2011.

E.2 Prevention of Future BES Reliability Risk

Describe how successful completion of the Mitigation Plan as laid out in Section D of this form will prevent or minimize the probability that your organization incurs further violations of the same or similar reliability standards requirements in the future:

The risk of recurrence of this issue is minimal. The Loss of Control Center Test Plan details the steps needed to meet the requirements of EOP-008 Requirement 1.5. The test results will be documented in the operator's log.

E.3 Your organization may be taking or planning other action, beyond that listed in the Mitigation Plan, as proposed in Section D.1, to prevent or minimize the probability of incurring further violations of the same or similar standards requirements listed in Section C.1, or of other reliability standards. If so, identify and describe any such action, including milestones and completion dates:

NSP is performing a comprehensive review of its compliance with all EOP-008 requirements, to be completed by 3/31/2012.

Section F: Authorization

An authorized individual must sign and date the signature page. By doing so, this individual, on behalf of your organization:

(a) Submits the Mitigation Plan, as laid out in Section D, to the Regional Entity for acceptance and approval by NERC, and

(b) If applicable, certifies that the Mitigation Plan, as laid out in Section D of this form, was completed (i) as laid out in Section D of this form and (ii) on or before the date provided as the 'Date of Completion of the Mitigation Plan' on this form, and

(c) Acknowledges:

1. I am Vice President - Transmission of Northern States Power (Xcel Energy)
2. I am qualified to sign this Mitigation Plan on behalf of Northern States Power (Xcel Energy)
3. I have read and understand Northern States Power (Xcel Energy)'s obligations to comply with Mitigation Plan requirements and ERO remedial action directives as well as ERO documents, including, but not limited to, the NERC Rules of Procedure and the NERC CMEP currently in effect or the NERC CMEP-Province of Manitoba, Schedule B currently in effect, whichever is applicable.
4. I have read and am familiar with the contents of the foregoing Mitigation Plan.
5. Northern States Power (Xcel Energy) Agrees to be bound by, and comply with, this Mitigation Plan, including the timetable completion date, as accepted by the Regional Entity, NERC, and if required, the applicable governmental authorities in Canada.

Authorized Individual Signature: ______________________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Name: Teresa Mogensen
Title: Vice President - Transmission
Authorized On: December 19, 2011

Certification of Mitigation Plan Completion

Submittal of a Certification of Mitigation Plan Completion shall include data or information sufficient for the Regional Entity to verify completion of the Mitigation Plan. The Regional Entity may request additional data or information and conduct follow-up assessments, on-site or other Spot Checking, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed and the Registered Entity is in compliance with the subject Reliability Standard. (CMEP Section 6.6)

Registered Entity Name: Northern States Power (Xcel Energy)

NERC Registry ID: NCR01020

NERC Violation ID(s): MRO201100332

Mitigated Standard Requirement(s): EOP-008-0 R1,

Scheduled Completion as per Accepted Mitigation Plan: April 30, 2012

Date Mitigation Plan completed: April 12, 2012

MRO Notified of Completion on Date: April 12, 2012

Entity Comment: EOP-008 Mitigation Plan has been completed.

Additional Comments		
From	Comment	User Name
Entity	Completion of Milestone 1 - documents NSP-PRO-A-010 Loss of Control Center Test Plan.doc Completion of Milestone 2 - documents Test Plan Review Meeting Notice.pdf and NSP-PRO-A-010 Loss of Control Center Test Plan.doc Completion of Milestone 3 - documents Review of EOP-008.doc, NSP Control Center Evacuation 2012_Jan21_handout.pdf, and Transmission Control Center_LMS_Evacuation Training.xls Completion of Milestone 4 - documents	Robert Thompson

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	NSP-PRO-A-010 Loss of Control Center Test Plan.doc	Loss of Control Center Test Plan	96,768
Entity	Test Plan Review Meeting Notice.pdf	Test Plan Review Meeting Notice	20,935
Entity	Review of EOP-008.doc	Review of EOP-008	42,496
Entity	NSP Control Center Evacuation 2012_Jan21_handout.pdf	NSP Control Center Evacuation Training document	2,658,948
Entity	Transmission Control	Training completion list for NSP control center	16,896

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Center_LMS_Evacuation Training.xls	evacuation training	16,896
Entity	NSP Wi Shift Schedule.xls	NSP Wi Shift schedule for Feb 2012	26,624
Entity	NSP MN Operator schedule 2-20 to 3-11.xls	NSP Mn shift schedule Feb 2012	19,968

I certify that the Mitigation Plan for the above named violation(s) has been completed on the date shown above and that all submitted information is complete and correct to the best of my knowledge.

Name: Robert Thompson
Title: Senior Consultant, Transmission Policy and Compliance
Email: robert.f.thompson@xcelenergy.com
Phone: 1 (612) 330-7968

Authorized Signature ______________________________ Date ________________
(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Certificate of Completion Review

Completion Date Entered by Entity:	04/12/2012
Region Notified of Completion On:	04/12/2012
Certification Document (Date Received from Entity):	
*Certification Reviewed By:	Riaz Islam
Actual Completion Date:	04/12/2012
Resubmission by Region On Date:	
Date Completion Verified by Region:	04/13/2012
Region Comment: **(Visible to Entity)**	
Private Review Comment: **(NOT Visible to Entity)**	On 4/12/2013 Riaz started entereing information into this record to verify complete but decided to request additional information from NSP so he hit save. Unfortunately, there was a glitch with webCDMS which caused the verified complete email notice to be generated and sent from the system. Jennifer Matz entered a help desk ticket #67576 with OATI on 4/17/12 to address this issue; OATI made the correction to webCDMS so this does not occur again, however, they were unable to have the system kick off another verified completed email. Regarding the correct verification of

Mitigation Plan

Registered Entity: Northern States Power (Xcel Energy)

NERC Violation ID	Requirement	Violation Validated On
MRO201100333	PRC-005-1 R2	08/26/2011

Mitigation Plan Submitted On: December 28, 2011
Mitigation Plan Accepted On: December 28, 2011
Mitigation Plan Proposed Completion Date: April 30, 2012
Actual Completion Date of Mitigation Plan:
Mitigation Plan Certified Complete by NSP On:
Mitigation Plan Completion Validated by MRO On:
Mitigation Plan Completed? (Yes/No): No

Section A: Compliance Notices

Section 6.2 of the NERC CMEP sets forth the information that must be included in a Mitigation Plan. The Mitigation Plan must include:

(1) The Registered Entity's point of contact for the Mitigation Plan, who shall be a person (i) responsible for filing the Mitigation Plan, (ii) technically knowledgeable regarding the Mitigation Plan, and (iii) authorized and competent to respond to questions regarding the status of the Mitigation Plan. This person may be the Registered Entity's point of contact described in Section B.
(2) The Alleged or Confirmed Violation(s) of Reliability Standard(s) the Mitigation Plan will correct.
(3) The cause of the Alleged or Confirmed Violation(s).
(4) The Registered Entity's action plan to correct the Alleged or Confirmed Violation(s).
(5) The Registered Entity's action plan to prevent recurrence of the Alleged or Confirmed violation(s).
(6) The anticipated impact of the Mitigation Plan on the bulk power system reliability and an action plan to mitigate any increased risk to the reliability of the bulk power-system while the Mitigation Plan is being implemented.
(7) A timetable for completion of the Mitigation Plan including the completion date by which the Mitigation Plan will be fully implemented and the Alleged or Confirmed Violation(s) corrected.
(8) Implementation milestones no more than three (3) months apart for Mitigation Plans with expected completion dates more than three (3) months from the date of submission. Additional violations could be determined or recommended to the applicable governmental authorities for not completing work associated with accepted milestones.
(9) Any other information deemed necessary or appropriate.
(10) The Mitigation Plan shall be signed by an officer, employee, attorney or other authorized representative of the Registered Entity, which if applicable, shall be the person that signed the Self Certification or Self Reporting submittals.
(11) This submittal form may be used to provide a required Mitigation Plan for review and approval by regional entity(ies) and NERC.

• The Mitigation Plan shall be submitted to the regional entity(ies) and NERC as confidential information in accordance with Section 1500 of the NERC Rules of Procedure.

• This Mitigation Plan form may be used to address one or more related alleged or confirmed violations of one Reliability Standard. A separate mitigation plan is required to address alleged or confirmed violations with respect to each additional Reliability Standard, as applicable.

• If the Mitigation Plan is accepted by regional entity(ies) and approved by NERC, a copy of this Mitigation Plan will be provided to the Federal Energy Regulatory Commission or filed with the applicable governmental authorities for approval in Canada.

• Regional Entity(ies) or NERC may reject Mitigation Plans that they determine to be incomplete or inadequate.

• Remedial action directives also may be issued as necessary to ensure reliability of the bulk power system.

• The user has read and accepts the conditions set forth in these Compliance Notices.

Section B: Registered Entity Information

B.1 Identify your organization:

Entity Name:	Northern States Power (Xcel Energy)
NERC Compliance Registry ID:	NCR01020
Address:	414 Nicollet Mall Minneapolis MN 55401

B.2 Identify the individual in your organization who will serve as the Contact to the Regional Entity regarding this Mitigation Plan. This person shall be technically knowledgeable regarding this Mitigation Plan and authorized to respond to Regional Entity regarding this Mitigation Plan.:

Name:	Brenda Prokop
Title:	Director, Compliance Monitoring & Policy
Email:	brenda.c.prokop@xcelenergy.com
Phone:	612-330-5642

Section C: Identification of Reliability Standard Violation(s) Associated with this Mitigation Plan

C.1 This Mitigation Plan is associated with the following violation(s) of the reliability standard listed below:

Violation ID	Date of Violation	Requirement
Requirement Description		
MRO201100333	10/01/2008	PRC-005-1 R2
Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30calendar days). The documentation of the program implementation shall include:		

C.2 Identify the cause of the violation(s) identified above:

The 1N2 and 1N6 relay schemes at the Monticello Nuclear Generating Plant (MNGP) were not tested within their respective established intervals as required by established plant and fleet procedures. The cause of both violations is human error for not following procedures. The violations were discovered while responding to an MRO audit-related data request.

The 1N2 relay scheme was originally scheduled to be tested on-line in October 2006. This test was properly deferred until October 2008, but was erroneously marked as complete in another work order.

The 1N6 relay scheme was originally scheduled to be tested during the spring 2009 outage. This test was not deferred and was dropped without justification. This activity was not timely identified as incomplete or past due because there currently is no computer tracking of outage-coded Preventive Maintenance requirements that are past due.

C.3 Provide any relevant information regarding the violation(s) associated with this Mitigation Plan: [If known]

While preparing responses to MRO's audit-related data request, a gap was identified in the 1N2 relay scheme testing. Additionally, it appeared that the 1N6 relay testing had not been completed since test records or written deferrals could not be located.

Fleet Guide FG-WM-PMA-01, Preventive Maintenance and Surveillance Administration, allows for work deferral, under certain circumstances. It specifies that when a surveillance procedure (test and/or inspection) cannot be completed within the required frequency, plus grace period, because current plant conditions and/or configurations will not permit performance, or when Operations Management, Responsible Engineer or Program Owner directs deferral of a non-Technical Specification test or inspection beyond the +25% grace period for any other reason, the procedure must be evaluated and processed to 1) document that the test/inspection requirement was addressed, 2) explain why it was not performed, 3) enable PassPort to continue to generate work orders at the required frequency, and 4) to ensure proper approval and documentation are obtained. The Fleet Guide was reviewed and found to be adequate. However, application of the deferral procedure, as it relates to the 1N2 and 1N6 relay schemes, was inadequate.

Section D: Details of Proposed Mitigation Plan

D.1 Identify and describe the action plan, including specific tasks and actions that your organization is proposing to undertake, or which it undertook if this Mitigation Plan has been completed, to correct the violation(s) identified above in Section C.1 of this form:

1. The 1N6 relay scheme was tested on February 13, 2011 and was found in calibration and functional [complete];

2. The 1N2 relay scheme was verified tested on November 5, 2010 and is in compliance with the requirements of PRC-005. [complete];

3. Verify that MNGP PRC-005 related tests have been performed in accordance with the established intervals. [complete];

4. Verify that the Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2 PRC-005 related tests have been performed in accordance with the established intervals. [complete]

5. Identify and track all MNGP and PINGP PRC-005 devices due to be tested prior to January 1, 2012 to ensure timely completion of scheduled activities during mitigation action plan period. [complete];

6. Perform an additional follow-up review of nuclear site protective relay systems and validate the identified scope of components to be tracked as PRC-005 Related. Make any necessary adjustments. [complete];

7. If any devices are added to the PRC-005 program for MNPG and PINGP, verify all have been tested within their established interval, and that testing is current. [complete];

8. Complete an investigation to determine the cause of the missed tests and establish corrective actions.

   a. CAP 01267263-02 - Potential NERC PRC-005 Violation-MNGP Relay [complete].
   b. CAP 01268379 - Missed PM interval for 1N2 relay testing [complete].
   c. CAP 01287507 - PRC-005: 1R cross trip PM beyond due date [complete].

9. Develop and implement an additional code to flag PRC-005 related protection systems in the equipment data base. This flag will allow these devices to be prioritized and queried for tracking/reporting purposes.

10. Revise applicable site-specific and fleet level procedures to ensure PRC-005-1 related activities are addressed. These changes will include the following enhancements:

   a. The creation of a document that clearly ties all pieces of the existing protection system maintenance and testing program together;
   b. Require an additional level of review for the testing of PRC-005 components
   c. Increase the priority level of PRC-005 related testing and maintenance
   d. Increase the rigor of review and approval

11. Communication
   a. Issue a formal communication to the impacted maintenance, engineering and scheduling personnel to increase awareness of PRC-005-1 testing requirements;
   b. Disseminate to all electrical maintenance and engineering personnel an information package that provides additional guidance on mandatory NERC compliance;

12. Training
   a. Perform a training analysis to assess the need for additional electrical maintenance and engineering training on NERC compliance;
   b. If additional training need is identified, develop and implement a fleet lesson plan for NERC Standards applicable to electrical maintenance and engineering.

13. For all relay schemes to be tested prior to March 31, 2012, perform independent checks to ensure testing is complete prior to the required due dates.

D.2 Provide the timetable for completion of the Mitigation Plan, including the completion date by which the Mitigation Plan will be fully implemented and the violations associated with this Mitigation Plan are corrected:

Proposed Completion date of Mitigation Plan: April 30, 2012

D.3 Milestone Activities, with completion dates, that your organization is proposing for this Mitigation Plan:

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
Test 1N6 relay scheme	Test 1N6 relay scheme	02/15/2011	February 13, 2011
Verify MNGP 1N2 Relay testing is current.	Verify MNGP 1N2 Relay testing is current.	02/28/2011	February 28, 2011
Initiate an investigation to determine cause(s) for missed testing.	Create Corrective Action Program (CAP) ticket(s) to initiate investigation efforts.	04/01/2011	January 21, 2011
Verify all devices currently in the PRC-005 program for MNPG were tested within prescribed interval.	Verify all devices currently in the PRC-005 program for MNPG were tested within prescribed interval.	06/29/2011	June 27, 2011
Verify all devices currently in the PRC-005 program for PINGP were tested within prescribed interval.	Verify all devices currently in the PRC-005 program for PINGP were tested within prescribed interval.	07/01/2011	June 30, 2011
Identify all devices for PINGP and MNPG due to be tested prior to Jan. 1, 2012	Identify all devices for PINGP and MNPG due to be tested prior to Jan. 1, 2012	07/01/2011	June 29, 2011
Review list of devices in scope of PRC-005 program for MNPG and PINGP and make any necessary changes.	Review list of devices in scope of PRC-005 program for MNPG and PINGP and make any necessary changes.	07/01/2011	June 29, 2011
If any devices are added to the PRC-005 program for MNPG and PINGP, verify all have been tested within their established interva	If any devices are added to the PRC-005 program for MNPG and PINGP, verify all have been tested within their established interval.	07/01/2011	June 30, 2011
Complete an investigation to determine the cause of the subject missed tests and establish corrective actions	Complete an investigation to determine the cause of the subject missed tests and establish corrective actions	09/15/2011	September 12, 2011
Perform a Training Needs Assessment for PRC-005 Program.	Perform a Training Needs Assessment for PRC-005 Program.	11/01/2011	October 25, 2011
Develop and implement an additional code to flag PRC-005 related protection systems in the equipment data base.	Develop and implement an additional code to flag PRC-005 related protection systems in the equipment data base.	11/15/2011	November 15, 2011

Milestone Activity	Description	*Proposed Completion Date (Shall not be greater than 3 months apart)	Actual Completion Date
Revise PRC-005-related program documentation	Revise PRC-005-related program documentation	02/14/2012	
Issue formal communication to impacted personnel	Issue formal communication to impacted personnel	03/01/2012	
For all relay schemes due to be tested prior to 03/31/2012, perform independent checks to ensure tested prior to each due date.	For all relay schemes due to be tested prior to 03/31/2012, perform independent checks to ensure tested prior to each due date.	03/31/2012	
Develop and Implement Fleet Training and Lesson Plan per needs Assessment.	Develop and Implement Fleet Training and Lesson Plan per needs Assessment.	03/31/2012	
Submit evidence and summary of internal controls.	Submit evidence of mitigation plan completion and summary of internal controls to MRO staff. Per MRO, internal controls include plan/process for measuring, reporting, and monitoring program performance within our company to prevent or minimize the probability of further violations of the same or similar reliability standards requirements; add statements about current/future plan, training, process, sampling and verification of schedule, actual maintenance and testing date, maintenance and testing records, etc.	04/06/2012	
Respond to data requests.	Provide additional information/ documentation, in response to MRO data requests, as part of the mitigation plan completion and validation process.	04/30/2012	

D.4 Additional Relevant Information (Optional)

Section E: Interim and Future Reliability Risk

E.1 Abatement of Interim BES Reliability Risk

While your organization is implementing the Mitigation Plan proposed in Section D of this form, the reliability of the Bulk Power System may remain at higher risk or be otherwise negatively impacted until the plan is successfully completed. To the extent they are, or may be, known or anticipated: (i) identify any such risks or impacts; and (ii) discuss any actions that your organization is planning to take or is proposing as part of the Mitigation Plan to mitigate any increased risk to the reliability of the bulk power system while the Mitigation Plan is being implemented:

We feel there is minimal risk to the BPS while this mitigation plan is being implemented, for the following reasons:
• The 1N6 and 1N2 protective relay schemes have been tested and found within their respective acceptance criteria and required no set point adjustments.
• No additional Monticello relay schemes were found to be out of their established testing interval.
• Relay schemes are due to be tested before the mitigation plan completion date of March 31, 2012. Since all of the mitigating actions will not yet be complete, an independent confirmation will be performed prior to each scheme's due date to ensure their timely completion.
• The scope of protection systems included in the PRC-005 program is being re-evaluated at both plants to ensure adequacy. If any protection systems are added to the program, we will verify they have been tested within their established interval and will immediately take any necessary mitigating actions.

E.2 Prevention of Future BES Reliability Risk

Describe how successful completion of the Mitigation Plan as laid out in Section D of this form will prevent or minimize the probability that your organization incurs further violations of the same or similar reliability standards requirements in the future:

The plan will assure that all PRC-005 protective devices are accounted for and scheduled appropriately in PassPort to ensure future test schedules are within their established interval. It will also apply another level of review for the testing of PRC-005 related components. Awareness will also be raised, through formal communication, with electrical maintenance and engineering personnel for recognition and application of PRC-005 requirements.

E.3 Your organization may be taking or planning other action, beyond that listed in the Mitigation Plan, as proposed in Section D.1, to prevent or minimize the probability of incurring further violations of the same or similar standards requirements listed in Section C.1, or of other reliability standards. If so, identify and describe any such action, including milestones and completion dates:

Section F: Authorization

An authorized individual must sign and date the signature page. By doing so, this individual, on behalf of your organization:

(a) Submits the Mitigation Plan, as laid out in Section D, to the Regional Entity for acceptance and approval by NERC, and

(b) If applicable, certifies that the Mitigation Plan, as laid out in Section D of this form, was completed (i) as laid out in Section D of this form and (ii) on or before the date provided as the 'Date of Completion of the Mitigation Plan' on this form, and

(c) Acknowledges:

1. I am VP, Engineering & Nuclear Regulatory Compliance and Licensing of Northern States Power (Xcel
2. I am qualified to sign this Mitigation Plan on behalf of Northern States Power (Xcel Energy)
3. I have read and understand Northern States Power (Xcel Energy)'s obligations to comply with Mitigation Plan requirements and ERO remedial action directives as well as ERO documents, including, but not limited to, the NERC Rules of Procedure and the NERC CMEP currently in effect or the NERC CMEP-Province of Manitoba, Schedule B currently in effect, whichever is applicable.
4. I have read and am familiar with the contents of the foregoing Mitigation Plan.
5. Northern States Power (Xcel Energy) Agrees to be bound by, and comply with, this Mitigation Plan, including the timetable completion date, as accepted by the Regional Entity, NERC, and if required, the applicable governmental authorities in Canada.

Authorized Individual Signature: ______________________________

(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

Name: Jim Molden

Title: VP, Engineering & Nuclear Regulatory Compliance and Licensing

Authorized On: December 23, 2011

Certification of Mitigation Plan Completion

Submittal of a Certification of Mitigation Plan Completion shall include data or information sufficient for the Regional Entity to verify completion of the Mitigation Plan. The Regional Entity may request additional data or information and conduct follow-up assessments, on-site or other Spot Checking, or Compliance Audits as it deems necessary to verify that all required actions in the Mitigation Plan have been completed and the Registered Entity is in compliance with the subject Reliability Standard. (CMEP Section 6.6)

Registered Entity Name: Northern States Power (Xcel Energy)

NERC Registry ID: NCR01020

NERC Violation ID(s): MRO201100333

Mitigated Standard Requirement(s): PRC-005-1 R2,

Scheduled Completion as per Accepted Mitigation Plan: April 30, 2012

Date Mitigation Plan completed: April 30, 2012

MRO Notified of Completion on Date: August 10, 2012

Entity Comment:

Additional Documents

From	Document Name	Description	Size in Bytes
Entity	MitPlan_PRC005_MoldenSign _122311.pdf		615,444
Entity	FP-MA-PRC-051.pdf	Evidence for milestone: Revise PRC-005-related program documentation	62,966
Entity	PRC-005 Communication.pdf	Evidence for milestone: Issue formal communication to impacted personnel	64,342
Entity	Milestone 15 NERC PRC-005 PPT.mht	Evidence for milestone: Develop and Implement Fleet Training and Lesson Plan per needs Assessment. (Training content)	3,745
Entity	Milestone 15 PRC-005 LMS Catalog.pdf	Evidence for milestone: Develop and Implement Fleet Training and Lesson Plan per needs Assessment. (LMS Catalog)	260,743
Entity	Milestone 15 Action Completion email.htm	Evidence for milestone: Develop and Implement Fleet Training and Lesson Plan per needs Assessment. (Training completion email)	5,171
Entity	Milestone 15 NERC Completions.pdf	Evidence for milestone: Develop and Implement Fleet Training and Lesson Plan per needs Assessment. (Personnel training completion records)	16,770
Entity	Milestone 14 Evidence MNGP PRC-005 Activities Jun 2011 to Mar 2012.xls	Evidence for milestone: For all relay schemes due to be tested prior to 03/31/2012, perform independent checks to ensure tested prior to each due date. (Monticello Nuclear Plant)	30,208
Entity	Milestone 14 Evidence PINGP PRC-005 Activities Jun 2011 to Mar 2012.xls	Evidence for milestone: For all relay schemes due to be tested prior to 03/31/2012, perform independent checks to ensure tested prior to each due date.	42,496

Additional Documents			
From	Document Name	Description	Size in Bytes
Entity	Milestone 14 Evidence PINGP PRC-005 Activities Jun 2011 to Mar 2012.xls	(Prairie Island Nuclear Plant)	42,496
Entity	MRO Mitigation Plan Summary.doc	Summary of mitigation plan completion and internal controls.	182,272
Entity	Nuclear PRC-005 Summary 20120426.xls	Updated spreadsheet of all PRC-005 program devices and the most recent two test dates, for both nuclear plants. (4/26/2012)	79,872
Entity	FP-WM-OVW-01-20100728.pdf	Work Management Process Overview (referenced in section 5.6.1 of FP-MA-PRC-05.pdf)	137,571
Entity	FP-PE-PM-01-20101201.pdf	Preventive Maintenance Program (referenced in section 5.8.1 of FP-MA-PRC-05.pdf)	113,868
Entity	MNGP EWI-11 01 06.pdf	Battery Monitoring and Maintenance Program (referenced in section 5.5.10 - 7a of FP-MA-PRC-05.pdf)	107,759
Entity	PINGP H37.pdf	Battery Monitoring and Maintenance Program (referenced in section 5.5.10 - 7a of FP-MA-PRC-05.pdf)	67,470
Entity	PRC-005 R2 Mitigation Plan Training.msg	Email statement related to training audience.	41,984

I certify that the Mitigation Plan for the above named violation(s) has been completed on the date shown above and that all submitted information is complete and correct to the best of my knowledge.

Name: Dennis Koehl
Title: Senior VP and Chief Nuclear Officer
Email: Dennis.Koehl@xenuclear.com
Phone: 1 (612) 330-6521

Authorized Signature ______________________________ Date ______________
(Electronic signature was received by the Regional Office via CDMS. For Electronic Signature Policy see CMEP.)

From:	noreply@oati.net
To:	cdms-mpstatus@midwestreliability.org
Subject:	[cdms-mpstatus] A Mitigation Plan has been verified as completed for Northern States Power (Xcel Energy) - MRO201100333 - PRC-005-1 R2
Date:	Friday, August 10, 2012 4:47:47 PM

Please do not REPLY to this message. It was sent from an unattended mailbox and replies are not monitored.

The following Mitigation Plan has been verified as completed by MRO.

Entity: **Northern States Power (Xcel Energy) - NCR01020**
NERC Violation ID:**MRO201100333**
Standard Requirement: **PRC-005-1 R2**
Mitigation Plan submitted on: **10/20/2011** (Version **1**), for Program Year: **2011**
Proposed Completion Date: **04/30/2012**
Actual Completion Date: **04/30/2012**
MRO Verified Completion Date on: **07/24/2012**

Note: This is a webCDMS application generated message. Please Do NOT respond to this email. If you have any questions regarding this notification, please contact:mitigation@midwestreliability.org.

[OATI Information - Email Template: MitPlan_Completed]

Attachment e

Notice of Filing

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Northern States Power (Xcel Energy) Docket No. NP13-___-000

NOTICE OF FILING
July 31, 2013

Take notice that on July 31, 2013, the North American Electric Reliability Corporation (NERC) filed a Notice of Penalty regarding Northern States Power (Xcel Energy) the Midwest Reliability Organization region.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: [BLANK]

Kimberly D. Bose,
Secretary