UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE RD. SUITE 210
LISLE, IL 60532-4352

November 4, 2014

Mr. Kevin Davison
Site Vice President
Prairie Island Nuclear Generating Plant
Northern States Power Company, Minnesota
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000282/2014004; 05000306/202014004

Dear Mr. Davison:

On September 30, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on October 7, 2014, with you and other members of your staff.

One NRC-identified and two self-revealed findings of very low safety significance (Green) were identified during this inspection. The findings were determined to involve violations of NRC requirements. A licensee-identified violation which was determined to be of very low safety significance is listed in this report. The NRC is treating these violations as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of any NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555–0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission–Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532–4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; and the Resident Inspector Office at the Prairie Island Nuclear Generating Plant. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Prairie Island Nuclear Generating Plant.

Additionally, as we informed you in the most recent NRC integrated inspection report, cross-cutting aspects identified in the last 6 months of 2013 using the previous terminology were being converted in accordance with the cross-reference in Inspection Manual Chapter (IMC) 0310. Section 4OA5 of the enclosed report documents the conversion of these cross-cutting aspects which will be evaluated for cross-cutting themes and potential substantive cross-cutting issues in accordance with IMC 0305 starting with the 2014 mid-cycle assessment review. If you disagree with the cross-cutting aspect assigned, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Prairie Island Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA Nick Shah, Acting for/

Kenneth Riemer
Branch 2
Division of Reactor Projects

Docket Nos. 50–282; 50–306; 72–010
License Nos. DPR–42; DPR–60; SNM–2506

Enclosure:
IR 05000282/2014004; 05000306/2014004
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50–282; 50–306; 72–010
License Nos:	DPR–42; DPR–60; SNM–2506
Report No:	05000282/2014004; 05000306/2014004
Licensee:	Northern States Power Company, Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, MN
Dates:	July 1 through September 30, 2014
Inspectors:	K. Stoedter, Senior Resident Inspector P. LaFlamme, Resident Inspector B. Boston, Reactor Engineer R. Elliott, Reactor Engineer N. Feliz-Adorno, Engineering Inspector M. Phalen, Senior Health Physicist P. Voss, Resident Inspector–Monticello P. Zurawski, Senior Resident Inspector–Monticello
Approved by:	K. Riemer, Chief Branch 2 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000282/2014004; 05000306/2014004; 07/01/2014–09/30/2014; Prairie Island Nuclear Generating Plant, Units 1 and 2; Operability Determinations and Event Followup.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Three Green findings were identified by the inspectors. These findings were considered non-cited violations (NCVs) of NRC regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process (SDP)" dated June 2, 2011. Cross-cutting aspects are determined IMC 0310, "Aspects Within the Cross-Cutting Areas" effective date January 1, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated July 9, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process" Revision 5, dated February 2014.

Cornerstone: Mitigating Systems

- Green. An inspector identified finding of very low safety significance and a NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings, occurred on August 31, 2014, due to the failure to follow Procedure FP–OP–OL–01, "Operability Determinations," while assessing the operability of three safety-related Agastat relays with unknown manufacturing dates. Specifically, licensee personnel failed to provide an adequate basis for concluding that there was a reasonable expectation that the relays would continue to perform their safety function(s). Corrective actions for this issue included changing out two of the relays and performing a technically adequate operability determination that complied with procedural requirements for the third relay.

  This deficiency was more than minor because if left uncorrected, the failure to perform operability determinations/recommendations in accordance with procedural requirements could result in incorrect conclusions and the failure to take action to correct degraded or deficient conditions. The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and determined that this issue was of very low safety significance because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "No." The inspectors concluded that this finding was cross-cutting in the Human Performance, Teamwork area because individuals and work groups failed to communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety was maintained (H.4). (Section 1R15.1)

- Green. A self-revealing finding and a NCV of Technical Specification 5.4.1 was identified on June 23, 2014, due to the failure to establish, implement and maintain the applicable procedures to address degraded power sources as recommended in Section 6 of Regulatory Guide 1.33, Revision 2, Appendix A, Revision 2. Specifically, Procedure 1C20.5, "Unit 1–4.16kV [kilovolt] System," failed to provide adequate guidance to address a degraded power condition on the 10 Bank Transformer, the 1R Transformer and Bus 15 (one of two safety-related 4.16 kV buses). This resulted in these components experiencing a low voltage condition for an extended period of time, Bus 15 voltage cycling near the degraded voltage actuation setpoint, and the automatic start of the D1 EDG. Corrective actions for this issue included repairing the equipment that led to the degraded voltage condition and revising Procedure 1C20.5 or developing a new procedure to provide guidance on responding to degraded voltage conditions.

This issue was more than minor because it impacted the procedure quality attribute of the Mitigating Systems cornerstone. In addition, the performance deficiency impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the lack of procedural guidance resulted in delaying operator action to restore voltage to Bus 15. The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and determined that this issue was of very low safety significance because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "No." The inspectors concluded that this finding was cross-cutting in the Human Performance, Resources area because the licensee had not ensured that procedures were available and adequate to support nuclear safety (H.1). (Section 4OA3.1)

- Green. A self-revealing finding of very low safety significance and a NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," was identified on June 23, 2014, due to the failure to properly implement Procedure 1C20.7, "D1/D2 Diesel Generators." Specifically, operations personnel were unable to comply with a caution statement prior to Step 5.3.5.H which directed that control switch CS–46950, "Bus 15 Source from D1 Diesel Generator," be placed in trip momentarily if D1 Emergency Diesel Generator (EDG) load was less than 100 kilowatts to prevent motorizing the EDG. The failure to implement the actions directed by the caution statement in a timely manner resulted in the D1 EDG tripping on reverse power. Corrective actions for this issue included briefing all operations personnel on this event and revising Procedure 1C20.7 to include additional information on EDG operation at low loads.

  This issue was more than minor because it impacted equipment performance attribute of the Mitigating Systems cornerstone. In addition, the performance deficiency impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to follow procedure resulted in the D1 EDG tripping on reverse power which extended the amount of time the EDG was inoperable. The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and determined that this issue was of very low safety significance because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "No." No cross-cutting aspect was assigned to this finding as none of the aspects directly related to why operations personnel were unable to comply with the proceduralized caution statements. (Section 4OA3.2)

- A Severity Level IV Violation that was identified by the licensee has been reviewed by the NRC. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program (CAP).

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period operating at full power. On August 31, 2014, operations personnel lowered reactor power to approximately 60 percent power due to a high temperature condition on the 11 circulating water pump motor. The licensee subsequently determined that the indicated high temperature condition was due to a failed temperature instrument. The licensee established an alternate temperature monitoring process and verified that the circulating water pump motor temperatures were within the vendor's specified limits. Based upon this information, operations personnel returned Unit 1 to full power on September 2, 2014. Unit 1 remained at full power for the remainder of the inspection period.

Unit 2 operated at full power for the entire inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity and Emergency Prepardness

1R01 Adverse Weather Protection (71111.01)

.1 External Flooding

a. Inspection Scope

From July 1 through July 8, 2014, operations personnel performed steps within Procedure AB-4, "Flooding," due to the 3-day predicted Mississippi River water level being greater than 678 feet.

The inspectors evaluated the design, material condition, and procedures for coping with the design basis probable maximum flood. The evaluation included a review to check for deviations from the descriptions provided in the Updated Safety Analysis Report (USAR) for features intended to mitigate the potential for flooding from external factors. As part of this evaluation, the inspectors checked for obstructions that could prevent draining, checked that the roofs did not contain obvious loose items that could clog drains in the event of heavy precipitation, and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed a walkdown of the protected area to identify any modification to the site which would inhibit site drainage during a probable maximum precipitation event or allow water ingress past a barrier. The inspectors also reviewed the abnormal operating procedure (AOP) for mitigating the design basis flood to ensure it could be implemented as written. Documents reviewed are listed in the Attachment to this report.

This inspection, and the inspection documented in Section 1R01 of NRC Inspection Report 05000282/2014003; 05000306/2014003, constituted one external flooding sample as defined in Inspection procedure (IP) 71111.01–05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- 11 Turbine Driven Auxiliary Feedwater Pump;
- 11 Containment Spray System; and
- Spent Fuel Pool Cooling System.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, the USAR, Technical Specification (TS) requirements, outstanding work orders (WOs), corrective action documents, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and were operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted three partial system walkdown samples as defined in IP 71111.04–05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

During the week of September 15–19, 2014, the inspectors performed a complete system alignment inspection of the Unit 1 and 2 vital direct current (DC) battery systems to verify the functional capability of the systems. These systems were selected because they were considered both safety significant and risk significant in the licensee’s probabilistic risk assessment. The inspectors walked down each system to review mechanical and electrical equipment lineups; electrical power availability; system voltage and temperature indications, as appropriate; component labeling; component and equipment cooling; hangers and supports; operability of support systems including battery chargers; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

These activities constituted one complete system walkdown sample as defined in IP 71111.04–05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Fire Detection Zone 11–Unit 1 Bus Room 16, Elevation 715';
- Fire Detection Zone 40–Unit 2 Auxiliary Building, Elevation 695';
- Fire Detection Zone 43–480 Volt Switch Gear 121, Elevation 715';
- Fire Detection Zone 46–Unit 2 Auxiliary Building, Elevation 715';
- Fire Detection Zone 53–Unit 2 Auxiliary Building, Elevation 755'; and
- Fire Detection Zone 97–D5/D6 Diesel Building.

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan.
The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the licensee's ability to respond to a security event. The inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment to this report.

These activities constituted six quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On September 24, 2014, the inspectors observed a crew of licensed operators in the simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator requalification program simulator sample as defined in IP 71111.11 and satisfied the inspection program requirement for the resident inspectors to observe a portion of an in-progress annual requalification operating test during a training cycle in which it was not observed by the NRC during the biennial portion of this IP.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On August 14, 2014, the inspectors observed operations personnel respond to an unexpected instrument air transient. In addition, the inspectors monitored the control room operator's response to an abnormal temperature condition on the 11 circulating water pump on August 31, 2014. These were activities that required heightened awareness or were related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;

- correct use and implementation of procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems or reviewed the following documents:

- Maintenance Rule (a)(3) Report and
- Cooling Water System (Functions 01 and 04).

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two quarterly maintenance effectiveness samples as defined in IP 71111.12–05.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- work activities associated with transporting dry cask 37 from the spent fuel pool to interim spent fuel storage installation pad;
- work activities associated with spent fuel pool cooling system modifications resulting in a planned orange risk condition;
- work activities associated with component cooling water system maintenance resulting in planned yellow risk condition;
- emergent work activities associated with Unit 1 & 2 A train cooling water system coupled with Unit 2 residual heat removal train A out of service for scheduled maintenance; and
- work activities associated with connecting a sand blaster to the instrument air system.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Documents reviewed are listed in the Attachment to this report.

These maintenance risk assessments and emergent work control activities constituted five samples as defined in IP 71111.13–05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Operability Recommendation (OPR) 1270104–01, Revision 6–Non Conservative Assumptions in Unit 1 Battery Calculations;
- OPR 1327157, Rev. 4–Evaluate Maximum Outside Air Temperature to Maintain Unit 1 Emergency Diesel Generator Rooms (EDG) Within Limits;
- CAP 1430398–Maximum Design Pressure Evaluation for Cooling Water Solenoid Operated Valves;
- OPR 1440603, Rev. 0–Agastat Relays Beyond Vendor Qualified Life; and
- OPR 1441423, Rev. 0–Void at Location 1RH-13 Could Cause Water Hammer Event Under Certain Conditions.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and the USAR to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

These operability inspections constituted five samples as defined in IP 71111.15–05.

b. Findings

Introduction: An inspector identified finding of very low safety significance and a NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings, occurred on August 31, 2014, due to the failure to follow Procedure FP–OP–OL–01, "Operability Determinations," while assessing the continued operability of three, safety-related Agastat relays with unknown manufacturing dates. Specifically, licensee personnel failed to provide an operability recommendation that sufficiently addressed the capability of the relays to perform their specified safety function(s).

Description: On July 28, 2014, the licensee initiated CAP 1440603 to document that an OPR was needed to evaluate the continued operability of three Agastat relays that were installed in plant equipment for longer than the vendor recommended service life of 10 years from the manufacturing date. The licensee performed an extent of condition review for this issue and identified that three additional relays currently installed in the plant had unknown manufacturing dates. These relays were associated with the safeguards screenhouse ventilation system and the safety injection system reset timer circuitry. The licensee documented this issue in CAP 1440681 on July 30, 2014. The shift manager on duty that day reviewed the CAP information and determined that the relays were operable until the manufacturing dates were known based upon their previous satisfactory performance. The shift manager also requested that the operability/functionality of these relays be evaluated as part of the OPR tied to CAP 1440603.

The OPR associated with CAP 1440603 was completed on August 8, 2014. On August 31, 2014, the inspectors reviewed OPR 1440603, "Agastat Relays beyond Vendor Qualified Life." The inspectors found that this OPR failed to evaluate the operability of the relays with the unknown manufacturing dates and provide a reasonable expectation that the relays would continue to perform their safety function(s). Instead, OPR 1440603 restated that the relays remained operable until the manufacturing dates were known.

The inspectors reviewed NRC IMC 0326, "Operability Determinations and Functionality Assessments for Conditions Adverse to Quality and Safety."

- Page 5 of IMC 0326 stated the following:

> "Reasonable expectation does not mean absolute assurance that the structure, systems, and/or components (SSCs) are operable. The SSCs may be considered operable when there is evidence that the possibility of failure of an SSC has increased, but not to the point of eroding confidence in the reasonable expectation that the SSC remains operable. The supporting basis for the reasonable expectation of SSC operability should provide a high degree of confidence that the SSC remains operable. It should be noted that the standard of "reasonable expectation" is a high standard, and that there is no such thing as an indeterminate state of operability."

The inspectors also reviewed Procedure FP–OP–OL–01, "Operability/Functionality Determination," Revision 13, and found that the procedure contained the same definition of reasonable expectation included in NRC IMC 0326. In addition, Step 5.3.1.3 of the procedure stated that operability determinations/recommendations shall be sufficient to address the capability of the SSC to perform its specified safety functions. The inspectors determined that since the ability of the three relays with the unknown manufacturing dates to perform their specified safety functions had not been addressed, OPR 1440603 had not adequately evaluated the relays continued operability.

The inspectors discussed their concerns and the contents of OPR 1440603 with a different shift manager on August 31, 2014. The shift manager documented the inspectors concerns in CAP 1445012. This shift manager's immediate operability call was that the relays were operable but nonconforming since the manufacturing dates were unknown. In addition, this shift manager provided a reasonable expectation of operability based upon information provided in Engineering Change (EC) 24376, "Evaluation of AGASTAT E7000 Series Time Delay Relay Service Life." The shift manager requested that a prompt operability determination be formally documented in an additional OPR.

On September 19, 2014, the licensee discovered that no progress had been made in documenting the OPR assigned by the shift manager on August 31, 2014. In response to this issue, the licensee installed new relays in the two safeguards screenhouse ventilation system applications. The licensee subsequently discovered that both relays were approximately 13 years old. The licensee determined that replacing the safety injection reset timer relay while Unit 1 was at power would lead to placing the plant in a high risk configuration due to the potential for an inadvertent safety injection system initiation signal. The licensee subsequently evaluated the continued operability of this relay by assuming the relay had been manufactured 40 years ago. Based upon the information provided in EC 24376, the licensee concluded that this relay would continue to operate for an additional 20 years. The inspectors agreed with the licensee's conclusions.

Analysis: The inspectors determined that the failure to perform an operability determination/recommendation as required by Procedure FP–OP–OL–01 was a performance deficiency associated with the Mitigating Systems cornerstone. This deficiency was more than minor because if left uncorrected, the failure to perform operability determinations/recommendations in accordance with procedural requirements could result in incorrect operability conclusions and the failure to take action to correct degraded or deficient conditions.

The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and determined that this issue was of very low safety significance (Green) because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "No." The inspectors concluded that this finding was cross-cutting in the Human Performance, Teamwork area because individuals and work groups failed to communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety is maintained (H.4).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented procedures of a type appropriate to the circumstance and be accomplished in accordance with these procedures. The licensee implemented the operability determination process (an activity affecting quality) using Procedure FP–OP–OL–01, "Operability/Functionality Determinations." Step 5.3.1.3 of the procedure stated that operability determinations/recommendations shall be sufficient to address the capability of the SSC to perform its specified safety function(s). Contrary to the above, on August 8, 2014, the licensee failed to complete OPR1440603 as required by Procedure FP–OP–OL–01. Specifically, the information in this OPR was not sufficient to address the capability of three relays with unknown manufacturing dates to perform their specified safety function.

Because this violation was of very low safety significance and was entered into the licensee's CAP as CAP 1445012, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000306/2014004–01: Failure to Perform Operability Determination as Required by Procedure)**. Corrective actions for this issue included performing an additional immediate operability determination on the relays, replacing two relays with relays with known manufacturing dates, and properly evaluating the third relay for continued operability based upon assuming the relay was manufactured approximately 40 years ago.

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modification:

- Engineering Change 21410, Rev. 0–Margin Recovery for D5/D6 Building Flood Protection (permanent).

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the USAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system(s). The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one permanent plant modification sample as defined in IP 71111.18–05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following post-maintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- SP 1102 following planned maintenance on the 11 turbine driven auxiliary feedwater pump;
- Operation of the 23 condensate pump following planned maintenance;
- SP 2089A following planned maintenance on 21 residual heat removal pump's 4 kV breaker; and
- Operation of the 12 component cooling water pump following planned maintenance.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the USAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

This inspection constituted four post-maintenance testing samples as defined in IP 71111.19–05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- SP 1090B–12 Containment Spray Pump Quarterly Test (Routine);
- SP 1095–Bus 16 Load Sequencer Test (Routine);
- SP 1101–12 Motor Driven Auxiliary Feedwater Pump Quarterly Pump & Valve Test (Routine);
- SP 1102–11 Turbine Drive Auxiliary Feedwater Quarterly Pump and Valve Test (Inservice test);
- SP 1106B–Train B Cooling Water Comprehensive Test (Routine); and
- SP 2073A–Train A Shield Building Ventilation Test (Routine).

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;

- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted five routine surveillance testing samples and one inservice testing sample as defined in IP 71111.22, Sections–02 and–05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Training Observation

a. Inspection Scope

The inspector observed a simulator training evolution for licensed operators on July 23, 2014, which required emergency plan implementation by a licensee operations crew. This evolution was planned to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that the licensee evaluators noted the same issues and entered them into the corrective action program. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the Attachment to this report.

This inspection of the licensee's training evolution with emergency preparedness drill aspects constituted one sample as defined in IP 71114.06–06.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

This inspection constituted a partial sample as defined in IP 71124.01–05.

.1 Risk-Significant High Radiation Area and Very High Radiation Area Controls (02.06)

a. Inspection Scope

The inspectors discussed with the Radiation Protection Manager (RPM) the controls and procedures for high risk, high radiation areas (HRAs) and very high radiation areas (VHRAs). The inspectors discussed methods employed by the licensee to provide stricter control of very high radiation area access as specified in 10 CFR 20.1602, "Control of Access to Very High Radiation Areas," and Regulatory Guide 8.38, "Control of Access to High and Very High Radiation Areas of Nuclear Plants." The inspectors assessed whether any changes to licensee procedures substantially reduce the effectiveness and level of worker protection.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

4OA1 Performance Indicator Verification (71151)

.1 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system (RCS) Leakage performance indicator for Units 1 and 2 for the period from the third quarter of

2013 through the second quarter of 2014. To determine the accuracy of the performance indicator (PI) data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, issue reports, event reports and NRC Integrated IRs for the period given above to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two reactor coolant system leakage samples as defined in IP 71151–05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment to this report.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the operator workarounds (OWAs) on system availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents.

The inspectors performed a review of the cumulative effects of OWAs. The documents listed in the Attachment to this report were reviewed to accomplish the objectives of the inspection procedure. The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into their CAP and proposed or implemented appropriate and timely corrective actions which addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an Initiating Event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Additionally, all temporary modifications were reviewed to identify any potential effect on the functionality of Mitigating Systems, impaired access to equipment, or required equipment uses for which the equipment was not designed. Daily plant and equipment status logs, degraded instrument logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified operator workarounds.

This review constituted one operator workaround annual inspection sample as defined in IP 71152–05.

b. Findings

No findings were identified.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)

.1 Inoperability of one Unit 1 Offsite Power Source and Bus 15 Due to Low Voltage Condition

a. Inspection Scope

On June 23, 2014, Unit 1 control room personnel declared one of two offsite power sources inoperable due to an unexpected low voltage condition. This condition resulted in safety-related Bus 15 also being declared inoperable. While attempting to transfer Bus 15 to the other offsite power source, the D1 EDG automatically started and powered Bus 15 due to detecting a degraded voltage condition. The inspectors monitored operator actions and equipment status from the control room. The inspectors also discussed the equipment inoperability, operator performance, and procedure adequacy with operations department management following this event. Documents reviewed are listed in the Attachment to this report.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

Introduction: A self-revealing finding and a NCV of TS 5.4.1 was identified due to the failure to establish implement and maintain the applicable procedures to address degraded power sources as recommended in Section 6 of Regulatory Guide 1.33, Revision 2, Appendix A, Revision 2. Specifically, Procedure 1C20.5, “Unit 1–4.16kV [kilovolt] System,” failed to provide adequate guidance to address a degraded power condition on the 10 Bank Transformer, the 1R Transformer and Bus 15. This resulted in a low voltage condition existing on these components for an extended period of time, Bus 15 voltage cycling near the degraded voltage actuation setpoint, and the automatic start of the D1 EDG.

Description: At 9:34 a.m. on June 23, 2014, control room personnel received a substation trouble alarm due to the 10 Bank Transformer load tap changer (LTC) failing. The failed LTC resulted in the 161 kV electrical system voltage dropping to 154 kV. During normal operations, the 161 kV electrical system supplied power to the 1R transformer (one of two TS credited Unit 1 offsite power sources). In turn, the 1R transformer supplied power to Bus 15 (one of two safety-related 4.16 kV switchgear for Unit 1). Due to the reduced voltage levels, operations personnel declared the 1R transformer and Bus 15 inoperable as required by TS. At the time, the voltage available to Bus 15 was less than 4000 Volts. However, the 4 kV bus voltage cycled above and below the degraded voltage actuation set point.

Over the next 90 minutes, operations personnel reviewed overall equipment conditions and believed that voltage could be restored to Bus 15 by transferring its power supply from the 1R transformer to the CT–11 transformer using Procedure 1C20.5. However, the operators were concerned that this action had the potential to adversely impact the CT–11 transformer and CT–11’s ability to continue to supply power to Bus 16 (the remaining, operable Unit 1 4.16 kV switchgear).

After discussing the course of action with other operations and engineering personnel, the control room operators moved forward with transferring Bus 15 to CT–11. During the course of the transfer, the operators voiced concern with the ability to meet

Step 5.15.6.C of Procedure 1C20.5 which required that the difference between the incoming and the running voltages be less than or equal to 8 Volts. Prior to reaching this procedure step, the operators received the Bus 15 degraded voltage alarm due to the Bus 15 voltage levels dropping below the degraded voltage actuation set point. Approximately one minute later, the D1 EDG started (as designed) and the Bus 15 power supply automatically transferred from the 1R transformer to the D1 EDG. The power supply transfer resulted in restoring Bus 15 voltage to greater than 4000 Volts. As a result, operations personnel declared Bus 15 operable at 11:07 a.m.

Once Bus 15 and D1 EDG conditions had stabilized, operations personnel began transferring Bus 15 from the D1 EDG to CT–11 using Section 5.3.5 of Procedure 1C20.7, "D1/D2 Diesel Generators." During this process, the D1 EDG shut down and locked out due to experiencing a reverse power condition (See Section 4OA3.2 below). Although operations personnel were able to successfully transfer Bus 15 to the CT–11 transformer, the reverse power condition resulted in the D1 EDG being declared inoperable.

The inspectors monitored the licensee's actions from the control room. The inspectors also discussed the events above with operations management. The inspectors determined that information provided in Procedure 1C20.5 was not appropriately established, implemented and maintained as required by TS 5.4.1 since it failed to adequately contain information regarding how to address a degraded source such as the one present on June 23, 2014. The procedure also lack guidance to aid the operator in restoring adequate voltage to a degraded 4.16 kV bus in a timely manner. The licensee subsequently determined that the LTC failed due to a failed relay. The relay was replaced and the LTC was returned to service at 8:32 p.m. on June 23, 2014.

<u>Analysis</u>: The failure establish, implement and maintain procedures to address degraded power sources as recommended in Section 6 of Regulatory Guide 1.33, Revision 2, Appendix A, Revision 2 was determined to be a performance deficiency that was required to be evaluated using the SDP. The inspectors determined that this issue was more than minor because it impacted procedure quality attribute of the Mitigating Systems cornerstone. In addition, the performance deficiency impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the lack of procedural guidance resulted in delaying operator action to restore voltage to Bus 15.

The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and determined that this issue was of very low safety significance (Green) because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "No." The inspectors concluded that this finding was cross-cutting in the Human Performance, Resources area because the licensee had not ensured that procedures were available and adequate to support nuclear safety (H.1).

<u>Enforcement</u>: Technical Specification 5.4.1 required, in part, that written procedures be established, implemented and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, Revision 2. Regulatory Guide 1.33, Revision 2, Appendix A, Revision 2, Section 6, required procedures to address losses of electrical power including degraded power sources. Contrary to the above, on June 23, 2014, Procedure 1C20.5, "Unit 1–4.16 kV System,"

was not established, implemented and maintained to address degraded conditions associated with Bus 15. This resulted in a low voltage condition existing on Bus 15 for an extended period of time and the automatic start of the D1 EDG to supply voltage to Bus 15 due to exceeding the degraded voltage actuation setpoint. Because this violation was of very low safety significance and was entered into the licensee's CAP as CAP 1436753, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2014004–02: Failure to have Adequate Procedures to Address Low Bus Voltage Conditions)**. Corrective actions for this issue included replacing the failed LTC relay and revising Procedure 1C20.5 or developing a new procedure to ensure degraded power sources were appropriately addressed.

.2 <u>(Closed) Licensee Event Report 05000282/2014–003–00: Emergency Diesel Generator Auto Start due to Degraded Bus Voltage Signal</u>

a. <u>Inspection Scope</u>

On June 23, 2014, Unit 1 control room personnel declared one of two offsite power sources inoperable due to an unexpected low voltage condition. This condition resulted in safety-related Bus 15 also being declared inoperable. While attempting to transfer Bus 15 to another offsite power source, the D1 EDG automatically started and powered Bus 15 due to detecting a degraded voltage condition. The inspectors monitored operator actions and equipment status from the control room. The inspectors also discussed the equipment inoperability, operator performance, and procedure adequacy with operations department management following this event. Documents reviewed are listed in the Attachment to this report. This licensee event report (LER) is closed.

This event follow-up inspection constituted one sample as defined in IP 71153–05.

b. <u>Findings</u>

<u>Introduction</u>: A self-revealing finding of very low safety significance and a NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," was identified due to the failure to properly implement Procedure 1C20.7, "D1/D2 Diesel Generators." Specifically, operations personnel were unable to comply with a caution statement prior to Step 5.3.5.H which directed that control switch CS–46950, "Bus 15 Source from D1 Diesel Generator," be placed in trip momentarily if D1 EDG load was less than 100 kilowatts to prevent motorizing the EDG. This resulted in the D1 EDG tripping on reverse power and being inoperable for approximately 10 hours.

<u>Description</u>: As discussed in Section 4OA3.1 above, the licensee experienced a low voltage condition on the 1R transformer and Bus 15 at 9:34 a.m. on June 23, 2014. While attempting to transfer power to Bus 15 from the 1R transformer to the CT–11 transformer the voltage levels dropped below the degraded voltage relay actuation setpoint. This resulted in an automatic start of the D1 EDG and the subsequent powering of Bus 15 by the D1 EDG.

After verifying stable voltage conditions on Bus 15 and normal operation of the D1 EDG, operations personnel began transferring power to Bus 15 from the D1 EDG to the CT–11 transformer using Section 5.3.5 of Procedure 1C20.7. During this evolution, the D1 EDG tripped on reverse power. This resulted in extending the total D1 EDG inoperability time by approximately 10 hours.

The inspectors reviewed Section 5.3.5 of Procedure 1C20.7 and identified that this section contained two caution statements just prior to Step 5.3.5.H. The first caution statement stated that D1 EDG load needed to be greater than 100 kilowatts (KW) prior to performing Step 5.3.5.H (which directed closing the breaker between Bus 15 and the CT–11 transformer) because the D1 EDG load would drop once this step was completed. The second caution statement said that if the D1 EDG load dropped to less than 100 KW upon performance of Step 5.3.5.H then immediate action needed to be taken to trip the breaker between the D1 EDG and Bus 15 as directed by Step 5.3.5.L to prevent motorizing (reverse powering) the EDG. The inspectors reviewed D1 EDG loading data provided by the Emergency Response Computer System (ERCS) and additional information provided by the engineering department. This data showed that the D1 EDG load was initially greater than 100 kW. However, EDG loading dropped from approximately 184 kW to–262 kW over a 48 second time span following the performance of Step 5.3.5.H. During this 48 second time period, the operator was performing procedural steps to remove volt amperes reactive (VAR) loading from the EDG by manipulating the D1 EDG exciter control switch. The inspectors determined that the need to closely monitor VAR loading while repetitively manipulating the D1 EDG exciter control switch, and the requirement to obtain a peer check prior to each control switch manipulation, distracted the operator from monitoring changes in EDG loading and complying with the caution statement that directed that Step 5.3.5.L be performed immediately to prevent motorizing the EDG.

Analysis: The inspectors determined that the failure to appropriately implement Section 5.3.5 of Procedure 1C20.7 was a performance deficiency since it resulted in the D1 EDG tripping on reverse power. This issue was more than minor because it impacted equipment performance attribute of the Mitigating Systems cornerstone. In addition, the performance deficiency impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to follow procedure resulted in the D1 EDG tripping on reverse power which extended the amount of time the EDG was inoperable.

The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and determined that this issue was of very low safety significance (Green) because each question provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," was answered "No." No cross-cutting aspect was assigned to this finding as none of the aspects directly related to why operations personnel were unable to comply with the proceduralized caution statements.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented procedures of a type appropriate to the circumstance and be accomplished in accordance with these procedures. The licensee established Section 5.3.5 of Procedure 1C20.7, "D1/D2 Diesel Generators," Revision 42, as the implementing procedure for transferring the power supply to Bus 15 from the D1 EDG to the CT–11 transformer. A caution statement located prior to Step 5.3.5.H of Procedure 1C20.7 stated the following:

"If, upon performance of Step 5.3.5.H, D1 load is less than 100 kW, then immediately perform Step 5.3.5.L to prevent motorizing the generators."

Contrary to the above, on June 23, 2014, operations personnel failed to immediately perform Step 5.3.5.L of Procedure 1C20.7 when the D1 EDG load became less than 100 kW. This resulted in motorizing the D1 EDG and caused the D1 EDG to trip on reverse power. Because this violation was of very low safety significance and was entered into the licensee's CAP as CAP 1435802, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2014004–03: D1 EDG Reverse Power Trip)**.

Corrective actions for the EDG reverse power trip including briefing all operations personnel on the event and revising Procedure 1C20.7 to increase the amount of load on the EDG prior to changing power supplies to a safety-related bus from an EDG to an offsite transformer. The decision to increase the amount of load resulted in increasing the amount of time available to perform the subsequent procedure steps prior to experiencing a reverse power condition.

.3 (Closed) Licensee Event Report 05000306/2014–002–00: 23 Fan Coil Unit Lower Northeast Face Corner Gasket Leaking

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the identification of a cooling water leak and the subsequent inoperability of the 23 containment fan coil unit and the Unit 2 containment on May 19, 2014. Documents reviewed are listed in the Attachment to this report. This LER is closed.

This event follow-up inspection constituted one sample as defined in IP 71153–05.

b. Findings

The issues discussed in the LER were documented as inspector identified findings of very low safety significance (Green) in Sections 1R20.1b(2)) and 4OA3.2 of NRC Integrated IR 05000282/2014003; 05000306/2014003. The inspectors noted that the NRC IR listed the date of the issue as May 18, 2014, while the LER stated the issue date as May 19, 2014. The difference in issue dates was due to the fact that the NRC first made the licensee aware of the fan coil leakage on the evening of May 18, 2014. However, the licensee failed to confirm the source of the leakage until May 19, 2014. See Sections 1R20.1b(2) and 4OA3.2 of the above NRC inspection report for additional details. The inspectors reviewed the LER and determined that no new information was provided.

4OA6 Management Meetings

.1 Exit Meeting Summary

On October 7, 2014, the inspectors presented the inspection results to Mr. K. Davison, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The inspection results for the area of radiological hazard assessment and exposure controls with Mr. K. Davidson, Site Vice President, on August 18, 2014.

The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.3 Regulatory Performance Meeting

On October 7, 2014, as part of the exit meeting associated with the 95001 inspection, the NRC met with the licensee to discuss their performance in accordance with Section 06.05.a.1 of IMC 0305. During this meeting, the NRC and licensee discussed the issues related to a white emergency alternating current mitigating systems performance indicator that resulted in Unit 2 being placed in the Regulatory Response Column of the Action Matrix. This discussion included the causes, corrective actions, extent of condition, extent of cause, and other planned licensee actions.

4OA7 Licensee-Identified Violations

The following Severity Level IV violation was identified by the licensee and is a violation of NRC requirements which met the criteria of Section 2.3.2 of the NRC Enforcement Policy for being dispositioned as a NCV.

.1 Risk-Significant High Radiation Area and Very High Radiation Area Controls (02.06)

Title 10 CFR 20.1601 requires control for access to high radiation areas (HRAs) and subpart (c) allows a licensee to apply to the NRC for approval of alternative methods for controlling HRA access. At Prairie Island Nuclear Generating Plant, the NRC-approved alternate methods for controlling access to HRAs include station TS 5.7. Specifically, TS 5.7.1.b for HRA access requires, in part, that "Access to, and activities in each such area shall be controlled by means of a Radiation Work Permit (RWP)…" Additionally, TS 5.7.1.e for HRA access requires, in part, that "…entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them."

Contrary to the above, on October 26, 2013, a worker willfully entered a posted and barricaded HRA inside the Unit-2 containment spray pump room on a RWP that did not authorize HRA entry and without being knowledgeable of the radiological conditions prior to entry. Corrective actions for this issue included performance management of the individuals involved in accordance with station management protocols. Because this violation was Severity Level IV, and it was entered into the licensee's CAP as CAP 1403583, this violation is being treated as a NCV consistent with Section 2.3.2 of the NRC Enforcement Policy.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

K. Davison, Site Vice President
S. Sharp, Site Operations Director
J. Hallenbeck, Site Engineering Director
C. Younie, Plant Manager
T. Allen, Assistant Plant Manager
J. Anderson, Regulatory Affairs Manager
J. Boesch, Production Planning Manager
T. Borgen, Training Manager
B. Boyer, Radiation Protection Manager
H. Butterworth, Nuclear Oversight Manager
F. Calia, Business Support Manager
C. Childress, Maintenance Manager
J. Corwin, Security Manager
K. DeFusco, Emergency Preparedness Manager
D. Gauger, Chemistry/Environmental Manager
B. Meek, Safety and Human Performance Manager
B. Rogers, Acting Performance Assessment Manager
J. Ruttar, Operations Manager

Nuclear Regulatory Commission

K. Riemer, Chief, Reactor Projects Branch 2
S. Wall, Project Manager, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000306/2014004–01	NCV	Failure to Perform Operability Determination as Required by Procedure
05000282/2014004–02	NCV	Failure to have Adequate Procedures to Address Low Bus Voltage Conditions
05000282/2014004–03	NCV	D1 EDG Reverse Power Trip

Closed

05000306/2014004–01	NCV	Failure to Perform Operability Determination as Required by Procedure
05000282/2014004–02	NCV	Failure to have Adequate Procedures to Address Low Bus Voltage Conditions
05000282/2014003–00	LER	Emergency Diesel Generator Auto Start due to Degraded Bus Voltage Signal
05000282/2014004–03	NCV	D1 EDG Reverse Power Trip
05000306/2014002–00	LER	23 Fan Coil Unit Lower Northeast Face Corner Gasket Leaking

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R04 Equipment Alignment

- Auxiliary Feedwater Maintenance Rule Bases Document; August 23, 2014
- Auxiliary Feedwater System Health Report; No Date
- CAP 1445144; Panel EM1-5 Drawing Load Discrepancies; September 2, 2014
- CAP 1446842; 11 DC Ground Alarm Upon Closure of 11 Portable Battery Charger Output; September 16, 2014
- Checklist C1.1.18-1; SI, CS, CA & HC System Checklist Unit 1; Revision 53
- Containment Spray System Health Report; No Date
- Drawing NF-40301-1; Wiring Diagram DC Distribution Panels "A" Train; Revision 81
- Open Auxiliary Feedwater Corrective Action Records; August 22, 2014
- Open Auxiliary Feedwater Work Orders August 22, 2014
- Procedure C20.9; Station Battery and Direct Current Distribution System; Revision 31
- Procedure C28-17; 11 Turbine Driven Auxiliary Feedwater Pump; Revision 8
- Procedure C28-2; Auxiliary Feedwater System Unit 1; Revision 51
- Procedure H37; Battery Monitoring and Maintenance Program; Revision 4
- SP 1187; Weekly Battery Inspection; Revision 30
- WO 395785-07; OPS: 11 Battery Charger Isolation Install Portable Charger; September 19, 2014
- WO 447338-05; SP 1314 12 Station Battery Discharge Test; November 22, 2012

1R05 Fire Protection

- 5AWI 8.5.0; Housekeeping and Material Condition; Revision 12
- F5 Appendix A; Fire Strategies; Revision 30
- F5 Appendix A; Fire Strategies; Revision 30
- F5 Appendix F; Fire Hazard Analysis; Revision 28
- Fire Detection Zone 11; Bus Room 16 Unit 1 715'; Revision 17
- Fire Detection Zone 40; Auxiliary Building Unit 2 695'; Revision 28
- Fire Detection Zone 43; 480V Switchgear 121; Revision 7
- Fire Detection Zone 46; Auxiliary Building Unit 2 715'; Revision 7
- Fire Detection Zone 54; Reactor Building Unit 2 755'; Revision 13
- Fire Detection Zone 97; D5/6 Diesel Building; Revision 30
- FP-PE-CC-01; Combustible Control; Revision 1

1R12 Maintenance Effectiveness

- CAP 1228034; 21 Cooling Water Pump Discharge Check Valves are Leaking By; April 20, 2010
- CAP 1331778; Reportable Automatic Start of 121 Motor Driven Cooling Water Pump; April 2, 2012
- CAP 1356357; Potential Leak on 12 Containment Fan Coil Unit Face; October 24, 2012

- CAP 1367342; Cooling Water Exceeds Maintenance Rule Unavailability Performance Criteria; January 22, 2013
- CAP 1370923; Could not Depressurize 21 Cooling Water Pump; February 9, 2013
- CAP 1379248; Perform a(1) Determination for Maintenance Rule Functional Failure 1356357; April 13, 2013
- CAP 1379254; Perform a(1) Determination for Maintenance Rule Functional Failure 1370923; April 17, 2013
- CAP 1413442; 21 Cooling Water Pump Isolation Requires B Train Limiting Condition for Operation; January 6, 2014
- CAP 1419352; a(1) Action Plan for Cooling Water System; Revision 0
- CAP 1422237; Maintenance Rule a(1) Plan Off Track; March 12, 2014
- CAP 1423814; 22 Diesel Driven Cooling Water Pump Air Start Failed to Disengage; March 22, 2014
- CAP 1429312; Cooling Water Maintenance Rule Function CL-01 Exceeded Performance Criteria; May 2, 2014
- CAP 1447276; Need for Cooling Water System Leakage Test; September 19, 2014
- CAPZ 1266075; Potential Licensee Event Report Issue on December 121 Motor Driven Cooling Water Pump Automatic Start; January 21, 2011
- Prairie Island Maintenance Rule Bases Document; Cooling Water System; August 25, 2014

1R13 Maintenance Risk Assessment and Emergent Work

- CAP 1345252; Water Level Increasing Beneath 12 CS Pump; July 18, 2012
- CAP 1439374; Oil Mist from Sandpiper Pump During Cask #37 Pump Down; July 22, 2014
- D21.1; Foreign Material Control of the Spent Fuel Pool Enclosure; Revision 14
- TP 1513; Spent Fuel Pool Enclosure Inspection; Revision 13
- WO 498935-15; Terminate Cables in Bus 16 Cubicle 5 per EC 17584; September 3, 2014

1R15 Operability Evaluations

- CAP 1290929; Void Found at Susceptible Location 1RH-09; June 16, 2011
- CAP 1291796; Generic Letter 08-01 Waterhammer Analysis Does Not Include All Scenarios; June 23, 2011
- CAP 1297439; Conduct a RCE for NRC BATT CHG Installation Finding; August 2, 2011
- CAP 1302208; OPR #1270104 Did Not Evaluate U1 DC Sys DBA Loads Past 1 hour; September 2, 2011
- CAP 1374401; Voids Found in Three Locations in Unit 1 Containment during TP 1468; March 13, 2013
- CAP 1430398; AOV Calc for Valves Maximum Allowed Air Pressure Exceeds Solenoid Valves Maximum Air Pressure; May 12, 2014
- CAP 1433509; Nuclear Oversight Finding – Inadequate Controls for Agastat Relay Aging Management; June 5, 2014
- CAP 1434449; Generic Letter 08-01 Void Found in Location 1RH-13; June 12, 2014
- CAP 1436765; 2-1/12CLP Agastat Relay Older than Vendor Qualified Life; June 30, 2014
- CAP 1440603; Operability Determination for Agastat Relays; July 28, 2014
- CAP 1440681; Unable to Identify Manufacturing Date for AGASTAT Relay; July 29, 2014
- CAP 1441077; Operability Declaration of Unqualified Safety Related Relays; July 28, 2014
- CAP 1443458; Agastat Relay Operability Recommendation Extent of Condition; August 19, 2014
- CAP 1445012; Time Delay Relay Operability not Assessed Appropriately; August 31, 2014
- CAP 1446908; SP 1314 Urgent Revision; September 17, 2014

- EC 24525; Evaluation of Additional Emergency Light Loads on 12 Battery; September 9, 2014
- NF-40315-2; Interlock Logic Diagram Cooling Water System; Revision 76
- NRC IN 88-24; Failures of Air-Operated Valves Affecting Safety-Related Systems; May 13, 1988
- Operating Experience Assessment for NRC IN 88-24; Revision 1
- OPR 1270104-01; Non Conservative Assumptions in Unit 1 Battery Calcs; Revision 6
- OPR 1290929-01; Void Found at Susceptible Location 1RH-09; Revision 0
- OPR 1291796; Generic Letter 08-01 Waterhammer Analysis Does Not Include All Scenarios; Revision 1
- Surveillance Procedure 1314; 12 Battery Refueling Outage Discharge Test; Revision 26
- WO 506925; Vent Air Void at Location 1RH-13; August 11, 2014

1R19 Post Maintenance Testing

- Procedure 1C14; Component Cooling System Unit 1; Revision 37
- Apparent Cause Evaluation 1408288; BKR 26-17 Failed to Close During SP-2144; January 17, 2014
- CAP 1400299; Seal Leak on 21 RHR Pump has Grown and Requires Evaluation; October 6, 2013
- CAP 1442074; Boric Acid Buildup on 21 RHR Pump Seal; August 7, 2014
- PINGP 1507 Rev 7; Boric Acid Corrosion Control Leak Inspection Evaluation; November 11, 2013
- SP 2089A; Train A RHR Pump and Suction Valve From the RWST Quarterly Test; August 7, 2014
- WO 492741; SP 1102-11 Turbine Driven AFW Pump Monthly Test; July 15, 2014
- WO 493922; SP2089A – Train A RHR PMP and SUCTIN VLV From RWST QTRLY Test; August 7, 2014
- WO 498935-15; CELE: Terminate Cables Bus 16 Cub 5 per EC 17584; September 3, 2014
- WO 498935-94; Missile Protection for Spent Fuel Pool HX (EC 17584); September 3, 2014

1R22 Surveillance Testing

- CAP 1413975; 16273 22 DD CLWP JCKT WTR HI TS Display Starting to Fail; January 9, 2014
- CAP 1425007; Unit 2 Auxiliary Building to Annulus Train A Differential Pressure Indication/Switch Found Out of Tolerance; April 1, 2014
- CAP 1428765; Unit 2 Auxiliary Building to Annulus Train B Differential Pressure Indication/Switch Found Out of Tolerance High; April 29, 2014
- CAP 1432261; Differential Pressure Switch Found Out of Tolerance High; May 27, 2014
- CAP 1441429; Oil Addition to 22 DD CLG WTR PMP; August 1, 2014
- SP 1090B; 12 Containment Spray Pump Quarterly Test; Revision 22
- SP 1095; Bus 16 Load Sequencer Test; Revision 35
- SP 1100; 12 Motor Driven AFW Pump Monthly Test; Revision 82
- SP 1101; 12 Motor-Driven Feedwater Pump Quarterly Flow and Valve Test; Revision 61
- SP 2073A; Monthly Train A Shield Building Ventilation System Test; Revision 9
- WO 493554-01; 22 Diesel Driven Cooling Water Pump Comprehensive Test; August 1, 2014
- WO 495117; SP1095 Bus 16 Load Sequencer; August 25, 2014
- WO 495156-01; SP1101 12 MD AFWP Quarterly Flow & Valve Test; August 28, 2014
- WO 495159-01; SP1090B 12 Containment Spray Pump Quarterly; August 22, 2014
- WR 99487; 16273 22 DD CLWP JCKT WTR HI TS Display Starting to Fail; January 9, 2014

2RS1 Radiological Hazard Assessment and Exposure Controls

- CAP 1403583; BHO Worker Logged on RA RWP Enters HRA; October 26, 2013
- F2; Radiation Safety; Revision 34
- FP-RP-RWP-01; Radiation Work Permit; Revision 13
- Prairie Island Radiation Protection Logs; October 25, 2013, through October 29, 2013
- Prairie Island Radiological Survey Record; PI-M-20131026-11
- Radiation Work Permit 1650-01; U2 Outage Radiation Area Work; October 26, 2013

4OA1 Performance Indicator Verification

- CAP 1412645; SP 2011AA Potential 0.2 gallon per minute and 1.0 gallon per minute leak due to 2R11 Readings; December 28, 2013
- Control Room Narrative Logs; various dates
- Procedure H60; Reactor Coolant System Leakage Monitoring Program; Revision 1
- Reactor Coolant System Identified Leakage Data; July 2013 – June 2014
- SP 1001AA; Daily Reactor Coolant System Leakage Test; Revision 58
- Technical Specification 3.4.14; Reactor Coolant System Operational Leakage; no date provided

4OA2 Identification and Resolution of Problems

- CAP 1368742; Tracking GAR for Operator Burdens; February 1, 2013
- CAP 1415315; Possible Failure of D6 ENG 1 HT CLG WTR Outlet LO TS; February 20, 2014
- CAP 1442287; 21 SI Pump Flow Indicator Swap Delays 21 SI Pump Work ;August 8, 2014
- CAP 1447141; Frequently Gas Binding 21 RCDT Pump- Unable to Drain PRT; September 18, 2014
- CAP 1447535; 2014 TCOA—OPR Comp Measure Not Listed as SWI)-35 TCOA; September 22, 2014
- FP-OP-OB-01; Operator Burden Program; Revision 6
- Operations Burden Log; September 18, 2014
- Operations Burden Report Summary September 19, 2014
- SWI O-35; Emergency Operating Procedure Verification; Validation & Maintenance; Revision 19
- Temporary Modification Report Update; September 16, 2014

4OA3 Event Followup

- Annunciator Response Procedure 47023-0601; Substation Local Alarm; Revision 34
- Annunciator Response Procedure C47024-0301; Bus 15 4.16 kV Degraded Voltage; Revision 35
- CAP 1435793; 10 Bank Transformer Load Tap Changer Not Functioning; June 23, 2014
- CAP 1435802; D1 DG Lockout on Reverse Current; June 23, 2014
- CAP 1440052; Missed Opportunity – Operating Experience Preventable Event; July 25, 2014
- Control Room Narrative Logs; June 23, 2014
- Equipment Causal Evaluation 1435793; 10 Bank Transformer Load Tap Changer Failure; July 25, 2014
- FP-OP-COO-01; Conduct of Operations; Revision 13
- NSPM Incident Investigation Report for Prairie Island Nuclear Generating Plant; Degraded Voltage Event; July 16, 2014
- Operating Experience Report 6026; Nine Mile Point Unit 1 Fire in Auxiliary Control Room due to Relay Failure; September 17, 1993

- Procedure 1C20.5; Unit 1 – 4.16 kV System; Revision 19
- Procedure 1C20.7; D1/D2 Diesel Generators; Revision 42
- System Description Manual B20.5; 4.16 kV Station Auxiliary System; Revision 8
- Updated Safety Analysis Report; Section 8; Revision 33

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
AOP	Abnormal Operating Procedure
CAP	Corrective Action Program
CFR	Code of Federal Regulations
DC	Direct Current
DRP	Division of Reactor Projects
EC	Engineering Change
EDG	Emergency Diesel Generator
ERCS	Emergency Response Computer System
HRA	High Risk Area
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
kV	Kilovolt
kW	Kilowatt
LER	Licensee Event Report
LTC	Load Tap Changer
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OPR	Operability Recommendation
OWA	Operator Workaround
PARS	Publicly Available Records System
PI	Performance Indicator
RCS	Reactor Coolant System
RPM	Radiation Protection Manager
RWP	Radiation Work Permit
SDP	Significance Determination Process
SSC	Structures, Systems or Components
TS	Technical Specification
USAR	Updated Safety Analysis Report
VAR	Volt Amperes Reactive
VHRA	Very High Risk Area
WO	Work Order

of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Prairie Island Plant.

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Sincerely,

/RA Nick Shah, Acting for/

Kenneth Riemer
Branch 2
Division of Reactor Projects

Docket Nos. 50–282; 50–306; 72–010
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