UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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LISLE, IL 60532-4352

August 9, 2012

Mr. Jim Molden
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 05000282/2012003; 05000306/2012003

Dear Mr. Molden:

On June 30, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated 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 July 17, 2012, with you and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

One NRC-identified and one self-revealed finding of very low safety significance (Green) were identified during this inspection. These two findings were determined to involve violations of NRC requirements. Additionally, the NRC has determined a Severity Level IV violation occurred. This traditional enforcement violation was identified with an associated finding. Further, 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) consistent with Section 2.3.2 of the NRC Enforcement Policy.

If you contest these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Prairie Island Nuclear Generating Plant. If you disagree with the cross-cutting aspect assignment 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.

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

Sincerely,

**/RA/**

Kenneth Riemer, Chief
Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000282/2012003; 05000306/2012003
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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| Docket Nos: | 50-282; 50-306; 72-010 |
| License Nos: | DPR-42; DPR-60; SNM-2506 |
| Report No: | 05000282/2012003; 05000306/2012003 |
| Licensee: | Northern States Power Company, Minnesota |
| Facility: | Prairie Island Nuclear Generating Plant, Units 1 and 2 |
| Location: | Welch, MN |
| Dates: | April 1, 2012 through June 30, 2012 |
| Inspectors: | K. Stoedter, Senior Resident Inspector<br>P. Zurawski, Acting Senior Resident Inspector<br>D. Betancourt, Acting Resident Inspector<br>S. Shah, Acting Resident Inspector<br>P. Cardona-Morales, Emergency Response Specialist<br>C. Moore, Operations Engineer<br>P. Voss, Resident Inspector – Monticello<br>C. Zoia, Operator Licensing Examiner |
| Approved by: | Kenneth Riemer, Chief<br>Branch 2<br>Division of Reactor Projects |

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## SUMMARY OF FINDINGS

IR 05000282/2012003, 05000306/2012003; 04/01/2012-06/30/2012; Prairie Island Nuclear Generating Plant, Units 1 and 2; Maintenance Risk & Emergent Work; and Event Followup.

This report covers a 3-month period of inspection by the resident and regional inspectors. One NRC-identified finding and one self-revealed finding of very low safety significance (Green) were identified during this inspection. These two findings were considered non-cited violations (NCVs) of NRC requirements. Additionally, one Severity Level IV violation was identified by the inspectors. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

### A. NRC-Identified and Self-Revealed Findings

**Cornerstone: Initiating Events**

- Green. A self-revealed finding of very low safety significance and a non-cited violation (NCV) of Technical Specification (TS) 5.4.1 occurred on February 21, 2012 due the licensee's failure to establish, implement and maintain procedures regarding power operations. Specifically, procedure 2C1.4 contained information regarding the operation of the moisture separator reheater control valves that conflicted with Westinghouse Vendor Technical Manual (VTM) XH-2-164-1, "572 MW Steam Turbine Operation and Control Manual." This conflict caused a feedwater heater high level condition during Unit 2 low power operations which resulted in a manual reactor trip. The licensee initiated corrective action document 1325986 to document the trip. Corrective actions for this issue included revising procedure 2C1.4 to eliminate the conflicting information.

  The inspectors determined that the failure to establish, implement and maintain procedures for power operation as required by TS 5.4.1 was a performance deficiency that required an SDP evaluation. The inspectors determined that this issue was more than minor because it was associated with the procedure quality attribute of the Initiating Events Cornerstone. This finding also impacted the cornerstone objective of limiting the likelihood of events that upset plant stability and challenged critical safety functions during shutdown as well as power operations. The inspectors determined that this issue was of very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available. The inspectors concluded that this issue was cross-cutting in the Problem Identification and Resolution, Corrective Action Program (CAP) area, because the licensee's resolution of a previous Unit 1 trip, due to the same cause, identified the differences in operation between the VTM and the operating procedures. However, the procedures were not revised and no evaluation was performed to determine why operating outside the designer's recommendation was acceptable (P.1(c)). (Section 4OA3.3)

**Cornerstone: Mitigating Systems**

- Green. A finding of very low safety significance and a non-cited violation (NCV) of 10CFR 50.65(a)(4) was identified by the inspectors due to the licensee's failure to properly assess plant risk upon obtaining information which challenged the continued availability of the 21 Residual Heat Removal (RHR) pump. On April 21, 2012, licensee personnel failed to promptly recognize the unplanned orange risk condition when the 21 RHR Pump vibrations exceeded the inservice test (IST) criteria of procedure SP 2092B, "Safety Injection Check Valve Test (Head Off) Part B: RWST to RHR Flow Path Verification." Corrective actions for this event included raising the reactor cavity level 20 feet above the reactor vessel flange per TS requirements.

  The inspectors determined that this issue was more than minor because, if left uncorrected, the failure to properly assess and manage risk could result in a loss of shutdown cooling (a more significant safety concern) due to a loss of the RHR function. Since Unit 2 was shut down in Mode 6, the Senior Risk Analyst (SRA) assessed the risk significance of the event in accordance with IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process." The SRAs reviewed Attachment 1, "Phase 1 Operational Checklists for Both PWRS and BWRS." The applicable checklist was Checklist 3, "PWR Cold Shutdown and Refueling Operation RCS Open and Refueling Cavity Level < 23' OR RCS Closed and No Inventory in Pressurizer Time to Boiling < 2 hours." The risk result was calculated to be 3.3E-7. Since the total estimated change in core damage frequency was greater than 1.0E-7/yr, the potential risk contribution for this finding from large early release frequency was screened using the guidance of IMC 0609, Appendix H, "Containment Integrity Significance Determination Process." The inspectors determined that this issue was of very low safety significance because it was not a design deficiency; it did not represent a loss of system safety function; it did not present a loss of safety function for one train for greater than the TS allowed outage time; and it did not screen as potentially risk significant due to a seismic, flooding or severe weather initiating event. This finding was determined to be cross-cutting in the Human Performance, Work Control area since the licensee did not plan and coordinate work activities consistent with nuclear safety (H.3(a)). (Section 1R13.1)

- Severity Level IV. The inspectors identified a Severity Level IV non-cited violation (NCV) of 10 CFR 50.73(a)(2) due to the failure to report required plant events or conditions within 60 days of discovery of the event. Specifically, the licensee failed to report that the Unit 1 emergency diesel generators (EDGs) had accumulated 2202 hours of inoperability due to not maintaining the required quantity of fuel oil. The licensee initiated corrective action document 1343001 to document this issue. Corrective actions for this issue included revising procedures to ensure that required events or conditions were reported within the required time.

  The inspectors determined that the failure to report required plant events or conditions to the NRC within the required time had the potential to impede or impact the regulatory process. As a result, the NRC dispositioned violations of 10 CFR 50.73 using the traditional enforcement process instead of the SDP. However, if possible, the underlying technical issue was evaluated using the SDP. In this case the inspectors determined that the failure to ensure the adequacy of design calculations as specified by 10 CFR 50, Appendix B, Criterion III, "Design Control," was the underlying technical issue to be evaluated using the SDP. Specifically, the licensee failed to verify that the fuel oil used at Prairie Island met the fuel energy content assumed in Design Calculation

ENG-ME-020. In addition, the licensee had not verified that the calculated net brake horsepower was applied correctly. The inspectors determined that this issue was more than minor because it was similar to Example 3.j of IMC 0612, Appendix E, and because it was associated with the design control attribute of the Mitigating Systems Cornerstone. The finding also affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors evaluated the finding in accordance with IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions." The fuel oil issue affected the 14-day supply needed for TS operability. However, the volume of fuel oil was adequate to support the 24-hour mission time assumed in the probabilistic risk assessment (PRA) mission time. In addition, the incorrect calculation of net brake horse power would not have prevented the EDGs from fulfilling their safety function. As a result, the finding was determined to be of very low safety significance. In accordance with Section 6.9.d.9 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the underlying technical issue was evaluated by the SDP and determined to be of very low safety significance. The inspectors concluded that this finding had no cross-cutting aspect since the inadequate calculations were performed more than three years ago and therefore not reflective of current licensee performance. (Section 4OA3.1)

## B. Licensee-Identified Violations

Violations of very low safety significance, which were identified by the licensee, have been reviewed by inspectors. Corrective actions planned or taken by the licensee have been entered into the licensee's CAP. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

## REPORT DETAILS

### Summary of Plant Status

Unit 1 operated at or near full power for most of the inspection period. On June 18, 2012, operations personnel lowered Unit 1 reactor power to 42 percent to perform condenser waterbox and Amertap screen cleaning. Operations personnel returned Unit 1 to full power on June 23, 2012. Unit 1 continued to operate at or near full power for the remainder of the inspection period.

Unit 2 began the inspection period shutdown for Refueling Outage 2R27. Operations personnel returned Unit 2 to power on May 28, 2012. The generator was synchronized with the electrical grid on May 29, 2012. Unit 2 was restored to full power on June 5, 2012. Unit 2 continued to operate at or near full power for the remainder of the inspection period.

## 1. REACTOR SAFETY

**Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity**

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate AC Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of offsite and onsite alternating current (AC) power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas and the communications protocols between the transmission system operator (TSO) and the licensee to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

- The coordination between the TSO and the licensee during off-normal or emergency events;
- The explanations for the events;
- The estimates of when the offsite power system would be returned to a normal state; and
- The notifications from the TSO to the licensee when the offsite power system was returned to normal.

The inspectors also verified that licensee procedures addressed measures to monitor and maintain availability and reliability of both the offsite AC power system and the onsite alternate AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

- The actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;

- The compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;
- A re-assessment of plant risk based on maintenance activities which could affect grid reliability, or the ability of the transmission system to provide offsite power; and
- The communications between the licensee and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one readiness of offsite and onsite AC power systems sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

.2 Summer Seasonal Readiness Preparations

a. Inspection Scope

The inspectors performed a review of the licensee's preparations for summer weather for selected systems, including conditions that could lead to an extended drought.

During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Safety Analysis Report (USAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Specific documents reviewed during this inspection are listed in the Attachment to this report. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures. The inspectors' reviews focused on the following plant systems:

- Instrument Air Compressor Krack Coolers (used to provide cooling to the auxiliary feedwater pumps);
- Steam Exclusion System; and
- D1 and D2 Emergency Diesel Generators (EDGs).

This inspection constituted one seasonal adverse weather sample as defined in IP 71111.01-05.

b. Findings

One unresolved item (URI) regarding the readiness of the Unit 1 EDGs for summer operations was identified. See Section 1R01.4 of this report for additional details.

.3 External Flooding

a. Inspection Scope

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 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.

This inspection constituted one external flooding sample as defined in IP 71111.01-05.

b. Findings

No findings were identified.

.4 Readiness For Impending Adverse Weather Condition – Extreme Heat/Drought Conditions

a. Inspection Scope

The inspectors performed a detailed review of the licensee's procedures and preparations for operating the facility during an extended period of time when ambient outside temperature was high, the ultimate heat sink was experiencing elevated temperatures, and the licensee was monitoring multiple pieces of mitigating systems equipment due to temperature concerns. The inspectors focused on plant specific design features and implementation of the procedures for responding to or mitigating the effects of these conditions on the operation of the cooling water, auxiliary feedwater, emergency diesel generator, and emergency core cooling systems. Inspection activities included a review of the licensee's adverse weather procedures, daily monitoring of the off-normal environmental conditions, and that operator actions specified by plant specific procedures were appropriate to ensure operability of the facility's normal and emergency cooling systems.

This inspection will not be counted as a sample as the inspection was ongoing at the conclusion of the inspection period.

b. Findings

Introduction: The inspectors identified an unresolved item (URI) regarding the licensee's preparations to ensure that the Unit 1 EDGs were ready for operation during extreme outside air temperatures.

Description: On June 8, 2011, the licensee provided a 10 CFR 50.72 report to the NRC when both of the Unit 1 EDGs (D1 and D2) were declared inoperable due to extreme

outside air temperatures. Specifically, the outside air temperature on June 8, 2011, was 101.4°F while the licensee's maximum temperature to support EDG operability was 100.5°F. Several weeks later, the licensee retracted the 10 CFR 50.72 report based upon additional analysis which showed that D1 and D2 remained operable up to a maximum outside air temperature of 102.5°F.

On February 29, 2012, the licensee initiated CAP 1327157 to document that the analysis used to support the 10 CFR 50.72 retraction discussed above was non-conservative. On April 15, 2012, the licensee completed an operability recommendation (OPR 1327157-01, Revision 0), to address the non-conservatisms. The results of the operability recommendation showed that the D1 and D2 EDGs were rendered inoperable when the outside air temperature exceeded 97°F.

During the week of June 26, 2012, the inspectors performed a maintenance effectiveness inspection on the D1 EDG (see Section 1R12 of this inspection report). As part of this inspection, the inspectors discovered Engineering Change (EC) 20055 which was approved by the engineering department on approximately June 10, 2012. The purpose of this EC was to evaluate the operability of the D1 and D2 EDGs over the past three years based upon a maximum outside air temperature. The inspectors reviewed the contents of the EC and were concerned that the licensee had assessed the past operability of the EDGs using a maximum outside air temperature of 105°F even though the temperature limit stated in the operability recommendation remained at 97°F. As a result, the licensee may not have properly reported periods of past EDG inoperability to the NRC. The inspectors also found that the licensee had approved increasing the maximum EDG room temperature without adequately assessing the impact of critical EDG components such as the diesel engine, the generator, and three lube oil pressure switches. Specifically, the licensee had deemed the continued operation of these components acceptable based upon engineering judgment without providing an appropriate basis for the conclusion.

The inspectors discussed their concerns, and the impending weather forecast which predicted temperatures in excess of 97°F, with engineering, operations, and licensee management personnel. Following these discussions, licensee management:

- rescinded the results of EC 20055;
- performed an additional review of the critical components to determine whether other actions could be completed to gain additional operability margin; and
- reaffirmed that the D1 and D2 EDG outside air temperature operability limit was 97°F.

At the conclusion of the inspection period, the licensee determined that additional margin could be gained by derating the EDG when outside air temperatures exceeded a specified temperature and by replacing the lube oil pressure switches with switches qualified for a higher operating temperature. The licensee replaced the D2 EDG lube oil pressure switches on June 30, 2012. The D1 EDG pressure switches were scheduled for replacement as soon as the weather conditions allowed.

The licensee also planned to perform testing on the replaced temperature switches to determine their maximum operating temperature. These test results will be used to determine whether the D1 and D2 EDGs had been inoperable at any time during the past three years. Since the test results were not available for inspection and review at

the conclusion of the inspection period, this issue will be documented as an unresolved item **(URI 05000282/2012003-05: Impact of Outside Air Temperatures on D1 and D2 EDG Operability)**.

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:

- 122 Control Room Chiller;
- 11 Turbine Driven Auxiliary Feedwater Pump; and
- 22 Residual Heat Removal Pump Alignment (RHR) with 21 RHR Pump Out of Service.

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, USAR, Technical Specification (TS) requirements, outstanding work orders (WOs), CAP items, 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 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.

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:

- Auxiliary Feedwater Pump Rooms (Fire Areas 31 & 32);
- Unit 1 695' Turbine Building (Fire Area 69, Zone 4);
- Unit 1 D2 EDG Room (Fire Area 26);
- Bus 15 & 16 Switchgear Rooms (Fire Areas 20 & 81);
- Unit 1 715' Turbine Building (Fire Area 69, Zone 15); and
- Plant Screenhouse (Fire Area 41).

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 licensee's Individual Plant Examination of External Events (IPEEE) 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. Using the documents listed in the Attachment to this report, 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.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On June 20, 2012, the inspectors observed fire brigade activation for a simulated fire in the old security building. Based on this observation, the inspectors evaluated the readiness of the fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies; openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were:

- proper wearing of turnout gear and self-contained breathing apparatus;
- proper use and layout of fire hoses;
- employment of appropriate fire fighting techniques;
- sufficient firefighting equipment brought to the scene;
- effectiveness of fire brigade leader communications, command, and control;
- search for victims and propagation of the fire into other plant areas;
- smoke removal operations;
- utilization of pre-planned strategies;

- adherence to the pre-planned drill scenario; and
- drill objectives.

Documents reviewed are listed in the Attachment to this report.

These activities constituted one annual fire protection inspection sample as defined in IP 71111.05-05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed licensee actions relative to the following:

- 121 Control Volume Control System (CVCS) Monitor Tank Overflow During Processing

On June 16, 2012, the 121 CVCS Monitor tank overflowed during transfer of water from the CVCS Hold-up tank. The overflow event consisted of approximately 1200 gallons of water which was primarily contained in the bermed area around the CVCS Monitor tanks. Additionally, an estimated 150 gallons leaked through floor penetrations in the bermed area down to the 715' elevation of the Auxiliary Building. No release occurred since this water was contained and routed to floor drains leading to the aerated sump tank.

Inspectors reviewed the event in relation to plant and safety-related equipment protection internal flooding events. In addition, the inspectors reviewed licensee documents to identify areas and equipment that may be affected by the event. The inspectors also reviewed the licensee's corrective action documents with respect to the event to verify the adequacy of the corrective actions.

Specific documents reviewed during this inspection are listed in the Attachment to this report. This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On the morning of June 12, 2012, the inspectors observed a crew of licensed operators in the simulator during licensed operator requalification activities to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was 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 (EP) 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 sample as defined in IP 71111.11.

b. Findings

No findings were identified.

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

a. Inspection Scope

On May 27-28, 2012, the inspectors observed activities in the control room during the Unit 2 startup for refueling outage 2R27. This was an activity that required heightened awareness or was 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 (if applicable);
- correct use and implementation of procedures;
- control board (or equipment) manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions.

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 (71111.12Q)

a. Inspection Scope

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

- Unit 1 D1 EDG
- Unit 2 Feedwater System

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:

- 21 RHR Pump during a period of high vibrations;
- 22 Component Cooling (CC) Heat Exchanger South End Bell Removal/Inspection;
- Refueling Test of Auxiliary Feedwater Discharge Check Valves;
- 23 Fan Coil Unit (FCU); and
- D5/D6 Load Sequencers

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. Specific documents reviewed during this inspection 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

Introduction: A finding of very low safety significance (Green) and a non-cited Violation (NCV) of 10CFR 50.65(a)(4) was identified by the inspectors due to the licensee’s failure to properly assess plant risk upon obtaining information which challenged the continued availability of the 21 RHR pump. Specifically, licensee personnel failed to promptly recognize the unplanned orange risk condition when the 21 RHR Pump vibrations exceeded the IST criteria of Procedure SP 2092B, “Safety Injection Check Valve Test (Head Off) Part B: RWST to RHR Flow Path Verification.”

Description: On April 23, 2012, during a review of the fact finding document generated by the licensee as a result of the failure of the 21 RHR pump, the inspectors noted elevated pump vibration readings. The document stated that a substantial change in vibration readings occurred on April 21, 2012 when both the 21 and 22 RHR pumps were being operated simultaneously. During operator monitoring on April 21, 2012, between 1122 and 1220 hours, elevated vibration was noted on all pump vibration points. The highest value was the upper “X” motor point with a local reading of approximately 0.46 inches per second (ips). After starting the 22 RHR pump,

the 21 RHR pump local vibration reading increased to 0.8 ips and the operators secured the pump after receiving notification of abnormal pump behavior from the local field operator observing the pump. A review of procedure SP 2092B, Revision 19, "Safety Injection Check Valve Test (Head Off) Part B: RWST to RHR Flow Path Verification," revealed that the pump was inoperable at an upper "X" local vibration reading of >0.6 ips. The inspectors reviewed the licensee's integrated risk management procedures, FP-OP-PEQ-01, "Protected Equipment Program {C001}," FP-WM-IRM-01, "Integrated Risk Management," and SWI O-59, "Protected Equipment Program," and discovered that the procedures required this failure to be screened for an elevated orange risk condition. The inspectors reviewed operator logs and determined that the licensee changed the plant risk status to orange at 1623 on April 22, 2012 when the pump failed due to a shaft shear.

The inspectors discussed their concern regarding failure to recognize the unplanned orange risk condition (which occurred at 1430 on April 21, 2012) and the 21 RHR pump unavailability with operations, engineering and management personnel. Licensee personnel agreed they did not recognize entry into the unplanned orange risk condition.

Analysis: The failure to properly assess and manage risk, specifically risk associated with the operability and availability of safeguards equipment, was a performance deficiency that required an SDP evaluation. The inspectors determined the finding was more than minor because it was associated with the Mitigating System Cornerstone attribute of Human Performance, and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to demonstrate compliance with risk management requirements resulted in the operators leaving the 21 RHR pump in service which eventually lead to the failure of the pump. This finding was determined to be of very low safety significance because each of the screening questions contained in IMC 0609.04, Table 4A, could be answered "no." The inspectors concluded that this finding was cross-cutting in the Human Performance, Work Control area since the licensee did not plan and coordinate work activities consistent with nuclear safety. (H.3(a)).

Enforcement: Title 10 CFR 50.65 (a)(4) requires, in part that licensees must properly assess and manage risk. Procedure FP-OP-PEQ-01, "Protected Equipment Program," states that redundant equipment should be protected when plant configuration would render protected equipment unavailable or has overall outage planned risk level change to an orange condition. Procedure FP-WM-IRM-01, "Integrated Risk Management," states that if plant conditions do not remain within specified limits, initial plant conditions have changed or modes have changed, then a review of the risk profile and contingency plans must be completed. It also states that if opposite train maintenance rule (a)(4) or TS equipment is inoperable, or other equipment is inoperable that is identified by operations as significantly impacting plant integrated risk, then the affect scheduled work order tasks should be reviewed to determine if they should be rescreened or rescheduled.

Contrary to the above, on April 21, 2012, the licensee personnel failed to properly assess and mange the risk associated with the unavailability of the 21 RHR pump. Specifically, licensee personnel failed to recognize that the pump would not be able to perform its required safety function when the high vibrations exceeded the IST criteria of procedure SP 2092B.

As a result, plant risk was not reassessed for high risk and additional risk management actions were not implemented. Because this violation was of very low safety significance and it had been entered into the CAP, 1334924, this violation is being treated as an NCV, consistent with Section 2.3.2 of NRC Enforcement Policy **(NCV 05000306/2012003-02: Failure to Properly Assess and Manage Risk)**. Corrective actions for this issue included implementing the required actions stated in TS.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following operability recommendations (OPRs):

- OPR 1335586 – Impact of Smaller Disc Installed in CV-31239;
- OPR 1324369 – Byron/Braidwood Undervoltage/Degraded Voltage;
- OPR 1331456 – Residual Heat Removal Heat-up Analysis;
- OPR 1327157 – D1/D2 Nonconservative Heat-up Analysis;
- OPR 1334863 – 21 RHR High Vibrations; and
- CAP 1342535 – 22 Safety Injection Pump Minimum Flow Recirculation Failed.

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 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.

This operability inspection constituted six samples as defined in IP 71111.15-05.

b. Findings

No findings were identified.

## 1R18 Plant Modifications (71111.18)

### .1 Plant Modifications

#### a. Inspection Scope

The inspectors reviewed the following modification:

- Unit 2 Reactor Head Vent Modification (Permanent).

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening evaluation 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; 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 and engineering 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 in the course of this inspection are listed in the Attachment to this report.

This inspection constituted one permanent modification samples 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:

- Bus 16 4.16KV Degraded Voltage Alarm Testing;
- 23 FCU Testing After Restoration from Service Water Leak;
- 2RC-8-14 Boric Acid Leak Repair;
- 22 Turbine-Driven Auxiliary Feedwater Pump (TDAFWP) Pump Testing after Governor Malfunction;
- 21 RHR Failure and Repair;
- 21 CC Pump Testing After Maintenance;
- Bus 26 Load Sequencer Relays; and
- Unit 2 Turbine/Stop Valve Testing.

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 eight post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed Unit 2 refueling outage (RFO) activities conducted between April 1 and May 29, 2012, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the RFO, the inspectors monitored licensee controls over the outage activities listed below:

- licensee configuration management, including maintenance of defense-in-depth commensurate with the Outage Safety Plan (OSP) for key safety functions and compliance with the applicable TS when taking equipment out of service;
- implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;
- controls over the status and configuration of electrical systems to ensure that TS and OSP requirements were met, and controls over switchyard activities;
- monitoring of decay heat removal processes, systems, and components;
- controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- controls over activities that could affect reactivity;
- maintenance of secondary containment as required by TS;

- licensee fatigue management, as required by 10 CFR 26, Subpart I;
- refueling activities, including fuel handling and sipping to detect fuel assembly leakage;
- startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing; and
- licensee identification and resolution of problems related to RFO activities.

Documents reviewed during the inspection are listed in the Attachment to this report.

This inspection constituted one RFO sample as defined in IP 71111.20-05.

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 1113, Steam Exclusion Annual Damper Inspection (routine);
- SP 1112, Steam Exclusion Monthly Damper Test (routine);
- SP 1305, D2 Diesel Generator Monthly Slow Start (routine);
- SP 2083A, Unit 2 Integrated Safety Injection (SI) Test with a Simulated Loss of Offsite Power Train A (routine);
- SP 2090B, 22 Containment Spray Pump Quarterly Test (routine); and
- SP 1090A, 11 Containment Spray Pump Quarterly Test (IST).

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and 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 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on May 12, 2012, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Simulator and Technical Support Center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment to this report.

This emergency preparedness drill inspection constituted one sample as defined in IP 71114.06-05.

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 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - High Pressure Injection Systems performance indicator (PI) for Prairie Island Nuclear Generating Plant, Units 1 and 2, for the period from the second quarter 2011 through the first quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of time given above to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP 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 MSPI high pressure injection system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Heat Removal System PI for Prairie Island Nuclear Generating Plant, Units 1 and 2, for the period from the second quarter 2011 through the first quarter 2012. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC

Integrated Inspection Reports for the period of time given above to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP 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 MSPI heat removal system 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 Physical Protection**

.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 that 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 CAP 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 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the six month period of December 2011 through May 2012, although some examples expanded beyond those dates where the scope of the trend warranted.

The inspectors also reviewed major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self assessment reports, and Maintenance Rule assessments to determine whether problems identified through these processes were entered into the licensee's CAP. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

This review constituted a single semi-annual trend 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 (Closed) Licensee Event Report (LER) 05000282/2012-001-00: Non-Conservative Calculation of Diesel Fuel Storage Requirements

a. Inspection Scope

On January 26, 2012, the licensee completed a past operability review regarding two errors that affected the fuel oil storage calculation for the Unit 1 EDGs. This error had the effect of increasing the volume of stored diesel fuel oil required to operate a Unit 1 EDG and a diesel-driven cooling water pump (DDCLP) for 14 days. The licensee submitted an LER for this condition on February 15, 2012. The inspectors reviewed the licensee's corrective action documents and the implementation of compensatory actions needed to address the condition described. The inspectors also confirmed that the licensee was in the process of developing permanent changes that included a license amendment as part of their corrective actions.

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

b. Findings

Introduction: The inspectors identified a Severity Level IV NCV of 10 CFR 50.73(a)(2) due to the failure to report required plant events or conditions within 60 days of discovery of the event. Specifically, the licensee failed to report that the Unit 1 EDGs had accumulated 2202 hours of inoperability due to not maintaining the required quantity of fuel oil.

Description: On October 27, 2011, an error was identified by the licensee in the pre-operational test records for the Unit 1 diesel generators. The error was in an equation used to calculate net break horsepower for the diesels; it consisted of an efficiency term that was used in the numerator instead of the denominator. Subsequently, on November 3, 2011, the NRC identified that the fuel energy content assumptions made in ENG-ME-020 "D1/D2 and DDCLP Fuel Oil Capacity" were not supported by the documents used to procure the EDG fuel oil used on site. In addition, calculation ENG-ME-020 used the low heat value in a correction ratio instead of the high heat value, which the inspectors determined was the appropriate term.

When the licensee re-performed the calculation to determine the new minimum fuel oil required, they noted that the 14 day supply needed to operate one Unit 1 EDG and a DDCLP, per TS, for a postulated maximum flood was non-conservative. The TS value was 65,500 gallons, while the new calculated value was 67,370.76 gallons. The licensee submitted a license amendment to revise the minimum required fuel needed for Unit 1 and has put compensatory actions in place. At the time the calculation was re-performed, the fuel supply for the Unit 1 EDGs and the DDCLP exceeded the new volume of fuel required. Therefore, at the time of discovery, there was enough fuel oil to support the operation of one Unit 1 EDG and a DDCLP.

The licensee performed EC-19427, "Past Operability Evaluation 1310238-03," to evaluate the effect that the two errors had on past operability. This review, which was completed on January 26, 2012, determined that over the last 3 years there was a total of 2202 hours of inoperability for the Unit 1 fuel oil system. As a result, both EDGs

were inoperable for greater than the TS allowed time. All the periods of inoperability occurred in 2010. The period with the maximum amount of continuous hours of inoperability was 738 hours. The licensee subsequently submitted a 10 CFR 50.73 LER on April 12, 2012.

During a review of this LER, the inspectors noted that the licensee had completed its past operability evaluation on January 26, 2012. However, the LER discovery date was listed as February 15, 2012. The inspectors questioned licensee personnel about the difference between what the inspectors determined was the discovery date and the date the licensee had reported in the LER. The licensee stated that they interpreted the discovery date as the date the reportability review was performed and not when the past operability review was completed. The inspectors reviewed NUREG-1022, “Event Reporting Guidelines 10 CFR 50.72 and 50.73,” Revision 2, Section 2.5 which states that: “The discovery date is generally the date when the event was discovered rather than the date an evaluation of the event was completed.” Based on the guidance in NUREG-1022, the inspectors determined that the LER was submitted 15 days late.

Analysis: The inspectors determined that the failure to report the conditions discussed above, as required by 10 CFR 50.73 (a)(2), within 60 days of discovery was a performance deficiency. The inspectors reviewed this issue in accordance with IMC 0612, Appendix B, and the discussion for Block 7, Figure 2, Paragraph 2.a.v., and determined that a failure to report within 60 days of discovery was an example of a violation that impacted the regulatory process and was subject to traditional enforcement. However, if possible, the underlying technical issue was required to be evaluated using the SDP. The NRC used the SDP results to determine the severity level of the traditional enforcement violation.

The inspectors determined that the failure to ensure the adequacy of the EDG fuel oil design calculations as specified by 10 CFR 50, Appendix B, Criterion III, “Design Control,” was a performance deficiency that could be evaluated using the SDP. The inspectors determined that this issue was more than minor because it was similar to Example 3.j of IMC 0612, Appendix E and because it was associated with the design control attribute of the Mitigating Systems Cornerstone. In addition, this issue affected the cornerstone’s objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors evaluated the finding in accordance with IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” Exhibit 2, "Mitigating Systems Screening Questions." The fuel oil issue affected the 14-day supply needed for TS operability. However, the EDGs were always available since there was an adequate amount of fuel oil to support the 24-hour PRA mission time of the EDGs. In addition, the incorrect calculation of net brake horse power would not have prevented the EDGs from fulfilling their safety function. As a result, the finding had very low safety significance (Green).

The inspectors also concluded that this finding had no cross-cutting aspect since it was not reflective of current licensee performance.

Enforcement: Title 10 CFR 50.73 (a)(2)(i)(b) requires, in part, that the licensee report, within 60 days any operation or condition which was prohibited by the licensee’s Technical Specifications(TSs).

Title 10 CFR 50.73 (a)(2)(v)(D) requires, in part, that the licensee report, within 60 days of any event or condition that could have prevented the fulfillment of a safety function needed to mitigate the consequences of an accident.

Title 10 CFR 50.73 (a)(2)(vii) requires, in part, that the licensee report, within 60 days any event where a single cause or condition caused two independent trains to become inoperable in a single system.

Contrary to the above, on March 26, 2012, the licensee failed to report the discovery of a condition prohibited by TS, an event or condition that could have prevented the fulfillment of a safety function needed to mitigate an accident, and the single cause inoperability of two trains of the same system within 60 days as required by 10 CFR 50.73. The licensee subsequently reported this condition to the NRC on April 12, 2012.

In accordance with the Enforcement Policy, this violation was classified as a Severity Level IV violation because the underlying technical issue was of very low risk significance. Because this issue was of a very low safety-significance, was not repetitive or willful, and was entered into the licensee's CAP as CAP 1343001, this violation is being treated as an NCV, consistent with Section 2.3.2 and Section 6.9 of the NRC Enforcement Policy **(NCV 05000282/2012003-03; Failure to Make a 60 Day Report Pursuant to 10 CFR 50.73)**. Corrective actions for this issue included revising procedures to ensure that the requirements as to when the 60 days for reporting LERs start.

Because the finding discussed above was evaluated separately using the SDP, it was required to be tracked separately and will be given a separate tracking number **(FIN 05000282/2012003-04; Failure to Make a 60 Day Report Pursuant to 10 CFR 50.73)**. Corrective actions for this issue included a license amendment request to revise the TS minimum required fuel oil volume for Unit 1 and the implementation of compensatory measures to maintain fuel oil levels for Unit 1 above the number determined by the new calculation.

.2 (Closed) Licensee Event Report (LER) 05000282/2012-002-00: Unplanned Actuation of 121 Motor Driven Cooling Water Pump

a. Inspection Scope

On April 2, 2012, operations personnel experienced an automatic start of the 121 motor driven cooling water pump (MDCLP). The MDCLP auto started while operations personnel were shutting down the 22 diesel driven cooling pump. The inspectors reviewed control room logs, corrective action documents, maintenance work records and training information to determine the sequence of events that resulted in the pump start.

Documents reviewed as part of this inspection are listed in the Attachment to this report. This LER is closed.

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

b. Findings

No findings were identified.

.3 <u>(Closed) Licensee Event Report (LER) 05000306/2012-001-00: Unit 2 Manual Reactor Trip Due To Feedwater Heater Hi Hi Alarm</u>

a. <u>Inspection Scope</u>

On February 21, 2012, Unit 2 was manually tripped from 11.42 percent power during a normal shutdown of the unit for refueling outage 2R27. The reactor was manually tripped in accordance with the 21/22/23 Feedwater Hi Hi Level alarm response procedure. The inspectors reviewed the licensee's LER and the equipment cause evaluation report to determine whether a performance deficiency led to the condition that caused the manual reactor trip.

Documents reviewed as part of this inspection are listed in the Attachment to this report. This LER is closed.

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

b. <u>Findings</u>

<u>Introduction</u>: A self-revealed finding of very low safety significance and an NCV of TS 5.4.1 occurred on February 21, 2012, due the licensee's failure to establish, implement and maintain procedures regarding power operations. Specifically, procedure 2C1.4 contained information regarding the operation of the moisture separator reheater (MSR) control valves that conflicted with Westinghouse Vendor Technical Manual (VTM) XH-2-164-1, "572 MW Steam Turbine Operation and Control Manual." This conflict contributed to the creation of a feedwater heater high level condition during Unit 2 low power operations and a manual reactor trip.

<u>Description</u>: On February 21, 2012, Prairie Island operations personnel were performing a normal shutdown of Unit 2 for refueling outage 2R27. The reactor was manually tripped at 11.42 percent power, as required by Alarm Response Procedure (ARP) 47502-0103 "21/22/23 Feedwater Heater Hi Hi Level," due to high levels in the 22A and 23A feedwater heater. The licensee initiated CAP 1325986 to document the reactor trip.

The inspectors reviewed the licensee's equipment cause evaluation report completed on April 6, 2012. This evaluation documented two potential causes for the event. The first stated that the third stage low pressure feedwater heater bypass line to the condenser was potentially undersized. This has the effect of restricting the rate at which water can go from the feedwater heaters into the condenser. The second cause identified the MSR control valves are closed earlier than necessary, at approximately 20 percent power, causing excessive moisture to accumulate in the low pressure heaters.

The inspectors determined that manual reactor trip due to high water levels in the low pressure feedwater heaters during low power operations (<20%) was a repeat event. In addition to the previously described Unit 2 reactor trip, a similar event occurred on April 30, 2011, with Unit 1. This event resulted in actions to modify the feedwater heater piping and a condition evaluation to evaluate revisions to shutdown operating procedures. Additionally, CAP 1286416 identified that that the low pressure turbine steam inlet temperature control was not being operated as specified by the associated Westinghouse VTM which specifically stated, "When reducing load, the reheater control valves should remain fully open until reaching 10 percent load." Contrary to these

VTM recommendations, procedure 2C1.4, "Unit 2 Power Operations," directed the operators to close the reheater control valves at 20 to 23 percent power. The licensee closed CAP 1286416 to CAP 1283119 which was also associated with the investigation of the Unit 1 Manual Reactor Trip that occurred on April 30, 2011. The evaluation for CAP 1283119 did not address the acceptability of operating the turbine outside vendor recommendations. In addition, the licensee determined that no changes to existing operating procedures were necessary.

Analysis: The inspectors determined that the failure to establish, implement and maintain procedures regarding power operations as required by TSs was a performance deficiency that required an evaluation using the SDP. Specifically, procedure 2C1.4 contained information regarding the operation of the MSR control valves that conflicted with Westinghouse VTM XH-2-164-1, "572 MW Steam Turbine Operation and Control Manual." The conflicting information led to a Unit 1 manual reactor trip on April 30, 2011, and a Unit 2 manual reactor trip on February 21, 2012.

This finding was more than minor because it was associated with the procedure quality attribute of the Initiating Events Cornerstone. The finding also impacted the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, as well as power operations. The inspectors evaluated this issue using IMC 0609, Attachment 4, Tables 3b and 4a, and determined it was of very low safety significance (Green) since it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available. The inspectors determined that this issue was cross-cutting in the Problem Identification and Resolution, Corrective Action Program area (P.1(c)), because the licensee's resolution of the 2011 trip did not address the differences in operation between the VTM and the operating procedures. In addition, there was no evaluation as to why operating outside the designer's recommendation was acceptable.

Enforcement: Technical Specification 5.4.1 requires that written procedures be established, implemented and maintained covering the applicable procedures recommended in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, February 1978. Section 2.g of RG 1.33, Revision 2, Appendix A, February 1978, requires procedures for power operation and process monitoring.

Contrary to the above, on February 21, 2012, the licensee failed to establish, implement and maintain procedure 2C1.4, "Unit 2 Power Operation," Revision 48. Specifically, procedure 2C1.4 directed the operators to ensure the reheater control valves started to close at the beginning of a power reduction by using the MSR control automatic shutdown program. The use of the automatic shutdown program resulted in the MSR control valves being fully closed at approximately 20 percent power. However, the Westinghouse VTM stated that the MSR control valves should remain open until reaching 10 percent. In addition, the licensee failed to have an evaluation to show why operating the plant outside of the Westinghouse VTM was acceptable. Because this violation was of very low safety significance and it was entered into the CAP as CAP 1325986, this issue is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000306/2012003-01: Unit 2 Reactor Trip due to Operation of Low Pressure Turbine Outside Its Design).** Corrective actions for this issue included revising procedures to resolve the conflict between the power operation procedure and the VTM. In addition, the licensee has an action to evaluate the

feasibility of increasing the size of the feedwater heater 3rd stage shell side on both units to ensure they are not restricting flow to the condenser at low power operation.

4OA5 Other Activities

.1 Institute of Nuclear Power Operations (INPO) Plant Assessment Report Review

a. Inspection Scope

The inspectors reviewed the final report for the INPO plant assessment conducted in October 2011. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to verify if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No findings were identified.

.2 (Closed) Unresolved Item 05000306/2011005-01: Potential Technical Specification Non-Compliance While Completing Repairs on Motor Damper 32421

a. Inspection Scope

As discussed in Section 1R01 of NRC Inspection Report 05000282/2011005; 05000306/2011005, the inspectors were concerned that the licensee had not complied with TS 3.8.1 while performing planned maintenance on Motor Damper (MD) 32421 (the 21 D5 EDG Room Exhaust Air Damper). Specifically, the inspectors were concerned that the night shift operations personnel had not complied with TS requirements due to incorrectly assessing the continued operability of the D5 EDG.

The inspectors reviewed the USAR, design basis documents, the D5 EDG room temperature information for November 11, 2011, and VTM information for the D5 EDG and the diesel ventilation system. The inspectors also reviewed information contained within CAPs 1312509 and 1313190. The inspectors concluded that the D5 EDG remained operable as long as the D5 EDG room temperature remained between 50 and 120 degrees Fahrenheit (°F) regardless of the dampers ability to modulate. The inspectors reviewed the D5 EDG room temperatures during the time the damper was removed from service and determined that the room remained within the above temperature limits. As a result, the night shift operations personnel had properly assessed the D5 EDG's operability prior to removing MD-32421 from service. No performance deficiencies or violations of TSs were identified. This item is closed.

b. Findings

No findings were identified.

.3 (Closed) Unresolved Item 05000306/2012002-08: Unit 2 Reactor Trip during Shutdown for Refueling Outage 2R27

a. Inspection Scope

The inspectors reviewed the licensee's causal evaluation and proposed corrective actions for a Unit 2 reactor trip that occurred on February 21, 2012.

b. Findings

A self-revealing finding of very low safety significance and an NCV of TS 5.4.1 were identified. See Section 4OA3.3 of this report for additional details.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 17, 2012, the inspectors presented the inspection results to J. Molden, Site Vice President, 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.

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by the licensee and was a violation of NRC requirements which met the criteria of the NRC Enforcement Policy for being dispositioned as a NCV.

- Procedure SWI NE-8, "Generation of Fuel Transfer Log," requires fuel assemblies removed from the reactor to be distributed into the final pattern no later than 60 days after reactor sub criticality in accordance with NRC commitment 01024151-01. Contrary to the above, during the Unit 2 refueling outage (2R27), the licensee failed to properly pre-plan and perform the distribution of fuel assemblies removed from the Unit 2 reactor within the time specified by written procedures. The licensee identified this issue on April 28, 2012, and generated CAP 1335689 to document the issue. Immediate corrective actions included moving the spent fuel into the designated final pattern and incorporating the embedded NRC commitment into another procedure which provided specific instructions to the outage management and work management department personnel.

  The inspectors determined that the failure to identify, evaluate, and implement requirements of SWI NE-8 regarding distribution of fuel assemblies removed from the reactor no later than 60 days after reactor sub-criticality was a performance deficiency. The inspectors determined the issue was more than minor because it impacted the design control attribute of the Barrier Integrity Cornerstone objective to provide reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events. Since this issue related to distribution of spent fuel during shutdown operations, the inspectors concluded the IMC 0609 Appendices associated with typical SDP evaluations did not apply. As a result, the inspectors contacted a regional Senior Reactor Analyst (SRA) for assistance in determining the

risk significance of this finding since the SDP for shutdown conditions did not address concerns regarding movement of fuel assemblies in the spent fuel pool. The SRA concluded that the use of IMC 0609, Appendix M, “Significance Determination Process Using Qualitative Criteria,” was the appropriate method for determining the significance. In accordance with IMC 0609, Appendix M, management review of this issue determined that this finding was of very low safety significance since no fuel assemblies were dropped, no unexpected reactivity conditions occurred, or no unanalyzed conditions existed.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee

J. Molden, Site Vice President
M. Schimmel, Site Vice President
K. Davison, Director – Site Operations
P. Huffman, Site Engineering Director
S. Northard,  Plant Manager
S. Sharp, Assistant Plant Manager
T. Allen, Senior Manager Site Engineering
J. Anderson, Regulatory Affairs Manager
J. Boesch, Acting Maintenance Manager
C. Bough, Chemistry and Environmental Manager
B. Boyer, Radiation Protection Manager
K. DeFusco, Emergency Preparedness Manager
J. Hamilton, Security Manager
C. Lane, Engineering Programs Manager
J. Lash, Nuclear Oversight Manager
S. Lappegaard, Production Planning Manager
M. Milly, Maintenance Manager
K. Peterson, Business Support Manager
A. Pullam, Training Manager
J. Ruttar, Operations Manager

Nuclear Regulatory Commission

K. Riemer, Chief, Reactor Projects Branch 2
T. Wengert, Project Manager, Office of Nuclear Reactor Regulation

## LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

| | | |
|---|---|---|
| 05000306/2012003-01 | NCV | Unit 2 Reactor Trip due to Operation of Low Pressure Turbine Outside its Design |
| 05000306/2012003-02 | NCV | Failure to Properly Assess and Manage Risk |
| 05000282/2012003-03 | NCV | Failure to Make a 60 Day Report Pursuant to 10 CFR 50.73 |
| 05000282/2012003-04 | FIN | Failure to Make a 60 Day Report Pursuant to 10 CFR 50.73 |
| 05000282/2012003-05 | URI | Impact of Outside Air Temperatures on D1 AND D2 EDG Operability |

Closed

| | | |
|---|---|---|
| 05000306/2012003-01 | NCV | Unit 2 Reactor Trip Due to Operation of Low Pressure Turbine Outside its Design |
| 05000306/2012003-02 | NCV | Failure to Properly Assess and Manage Risk |
| 05000282/2012003-03 | NCV | Failure to Make a 60 Day Report Pursuant to10 CFR 50.73 |
| 05000282/2012003-04 | FIN | Failure to Make a 60 Day Report Pursuant to10 CFR 50.73 |
| 05000306/2011005-01 | URI | Potential Technical Specification Non-compliance while Completing Repairs on Motor Damper 32421 |
| 05000306/2012002-08 | URI | Unit 2 Reactor Trip During Shutdown for Refueling Outage 2R27 |
| 05000282/2012-002-00 | LER | Unplanned Actuation of 121 Motor Driven Cooling Water Pump |
| 05000306/2012-001-00 | LER | Unit 2 Manual Trip Due to Feedwater Heater HI HI Alarm |
| 05000282/2012-001-00 | LER | Nonconservative Calculation of Diesel Fuel Storage Requirements |

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## LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of 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.

1R01 Adverse Weather

- 2011-S-048-W-MISO Standing Operations Guide; PINGP Transmission Operations Guide; Revision 2
- C20.3 AOP1; Evaluating System Operating Conditions w/ Security Analysis Out of Service; Revision 9
- C20.3 AOP12; Grid Voltage or Frequency Disturbances; Revision 5
- CAP 1333921; SP 1039 – Missile Hazards Identified in Area Two; April 16, 2012
- CAP 1334009; SP 1039 – More than Three Tornado Hazards Found in a Single Area; April 16, 2012
- CAP 1338613; TP-1636; May 22, 2012
- Control Room Narrative Logs
- PINGP – System Health Report; D1 Diesel Generator; June 22, 2012
- PINGP – System Health Report; D2 Diesel Generator; June 22, 2012
- PINGP – System Health Report; D5 Diesel Generator; June 22, 2012
- PINGP – System Health Report; D6 Diesel Generator; June 22, 2012
- PINGP – System Health Report; D6 Diesel Generator; June 22, 2012
- PINGP – System Health Report; ST Cooling Tower Substation; June 22, 2012
- PINGP – System Health Report; SY Plant Substation; June 22, 2012
- QF-0739; NRC Question Response Form for TP-1636; Revision 1
- SP 1039; Tornado Hazard Site Inspection; Revision 16
- Technical Specifications
- TP 1636; Summer Plant Operation; Revision 25
- Various Procedure Change Requests for TP-1636; Revision 25
- WO 427757-01; TP 1636 Annual Summer Plant Operation; March 30, 2012

1R04 Equipment Alignment

- CAP 1332269; 122 Control Room Chiller Oil Sump Temperature Observed at 126 Degrees; April 4, 2012
- Checklist C28-2; Auxiliary Feedwater System Unit 1; Revision 49
- Checklist C37.11-1; Chilled Water Safeguards System; Revision 20
- Checklist C37.9-1; Control, Relay and Computer Room Ventilation; Revision 12
- Flow Diagram NF-39222; Feedwater and Auxiliary Feedwater – Unit 1; Revision 80
- Flow Diagram NF-39222-2; Auxiliary Feedwater Pump Lube Oil System; Revision 0
- Procedure C37.9; Control, Relay and Computer Room Ventilation; Revision 26

1R05 Fire Protection

- Calibration Card History for Loop FPZ-001; No Date
- Calibration Card History for Loop FPZ-006; No Date
- Calibration Card History for Loop FPZ-011; No Date

- Calibration Card History for Loop FPZ-074; No Date
- Calibration Card History for Loop FPZ-075; No Date
- CAP 1333264; Blank Lines in Completed Work Order from 2010 Found by NRC; April 11, 2012
- CAP 1333294; Fire Detection Zone Map Questions from NRC; April 11, 2012
- CAP 1333633; F5 App F Door Information Needs to be Updated; June 29, 2012
- CAP 1342528; F5 App A discrepancy found by NRC during fire drill; June 21, 2012
- Fire Hazards Analysis
- FPEEE-12-003; CA-01311046-01; Fire Doors 257, 258, 259& 260; Revision 0
- FPEEE-12-003; CA-01311055-01; Fire Door Frames; Revision 0
- GEN-PI-026; Safe Shutdown Analysis for Compliance with 10 CFR 50 Appendix R, Section III. G; Revision 6
- PINGP 1676; Fire Drill Critique Report; June 29, 2012
- Procedure F5 Appendix E; Fire Protection Safe Shutdown Analysis Summary; Revision 14
- Procedure F5 Appendix F; Fire Hazard Analysis; Revision 25
- Procedure F5, Appendix A; Fire Zone Plans and Maps; Various Revisions
- Safe Shutdown Analysis
- Station Logs; October 19- 20, 2010
- WO 371767; ICPM 0-001.74, Fire Detection Zone Detector Calibration/Repair; November 25, 2009
- WO 373364; ICPM 0-001.75, Fire Detection Zone Detector Calibration/Repair; September 12, 2009
- WO 392293; ICPM 0-001.1, Fire Detection Zone Detector Calibration/Repair; June 1, 2010
- WO 392607; SP 1203, Fire Hose Hydrostatic Test; October 29, 2010
- WO 398487; ICPM 0-001.11, Fire Detection Zone Detector Calibration/Repair; December 15, 2010
- WO 399573; ICPM 0-001.6, Fire Detection Zone Detector Calibration/Repair; July 1, 2011
- WO 411132; SP 1266; Fire Damper – 18 Month Inspection; June 23, 2011
- WO 416763; SP 1203, Fire Hose Hydrostatic Test

1R06 Flood Protection (Internal)

- CAP 1341920; Stop Work Due To Error While Performing SP 1028A, WO 432690; June 15, 2012
- CAP 1341930; 121 CVCS Monitor Tank Overflowed During Processing; June 15, 2012
- WO 447191; Radiation Survey Record; June 15, 2012
- WO 447191; Radiation Survey Record; June 16, 2012

1R11 Licensed Operator Requalification

- 2C1.2; Unit 2 Startup Procedure; Revision 54
- C1B; Appendix – Reactor Startup; Revision 19
- D30; Post Refueling Startup Testing; Revision 51
- Simulator Exercise Guide P9112SE-0301; LOR Cycle 12C Simulator/DEP Evaluation No.1; Revision 0

1R12 Maintenance Effectiveness
- CAP 1329077; Significant Maintenance Rule Issues Identified; March 13, 2012
- Functional Failure Determinations; various dates

- Maintenance Rule Compliance Gap Analysis; no date
- System Health Reports

1R13 Maintenance Risk Assessment and Emergent Work

- CAP 1276780; Risk to EPU LAR due to HELB methodologies; March 22, 2011
- CAP 1280417; SP 1094 Bus 15 Load Sequencer Test Failed due to a 605 Error Code; April 13, 2011
- CAP 1281369; Load Sequencer DCV Monitor Lacks Sufficient Acceptance Criteria; April 19, 2011
- CAP 1282243; Bus 15 Load Sequencer Voltage Monitor Conformance Issue; April 25, 2011
- CAP 1293126; Maintenance Work Order Planning and Integrated Risk Management; July 4, 2011
- CAP 1320625; Maintenance Rule CW System Specific Basis; January 13, 2012
- Clearance Order 47337; Unit 1 Spent Fuel Pool Cooling System; May 15, 2012
- Clearance Order 48265; Unit 2 Residual Heat Removal System; May 14, 2012
- Clearance Order 48778; Unit 2 Auxiliary Feedwater System; May 14, 2012
- Clearance Order 48842; Protected Equipment for Mode 4 Change, 23 FCU OOS Risk Assessment; May 21, 2012
- FP-OP-PEQ-01; Protected Equipment Program {C001}; Revision 7
- FP-WM-IRM-01; Integrated Risk Management; Revision 6
- PORC #3227 Meeting Agenda; May 21, 2012
- SP 2359; Refueling Test of Auxiliary Feedwater Discharge Check Valves; Revision 13
- SWI O-59; Protected Equipment Program; Revision 7
- Unit 2 Shutdown Safety Assessment; May 14, 2012
- V.SPA.12.008; Mode Change Assessment-23 FCU (Mode 5 to 4); May 21, 2012

1R15 Operability Evaluations

- Bechtel Power Corporation Letter; Observations and Tentative Conclusions – 21 RHR Shaft Failure; May 2, 2012
- CAP 1266815; Extent Of Condition On Room Heat Up Issues; January 18, 2011
- CAP 1326085; 2RH-3-2 21 RHR Pump Suction Check Failed; May 17, 2012
- CAP 1327157; D1 and D2 Room Heatup Non-Conservatisms; February 29, 2012
- CAP 1331456; RHR Pit Heatup Analysis; March 29, 2012
- CAP 1334397; Increases Vibes On 21 RHR Pump; April 19, 2012
- CAP 1334565; High Vibes On 21 RHR Pump; April 19, 2012
- CAP 1334854; High Vibes On 21 RHR Pump During SP 2466; April 21, 2012
- CAP 1334863; Unplanned LCO 3.9.6.A 21 RHR Pump Vibration Issues; April 21, 2012
- CAP 1334924; 21 RHR Pump Failed During Troubleshooting; April 22, 2012
- CAP 1334933; Stop Work Issued Due To Entry Into Orange SSA Path; April 22, 2012
- CAP 1335754; 21 RHR Pump Vibrations High During PMT; April 28, 2012
- CAP 1335892; Potential For A Missed Availability Call On 21 RHR Pump; April 30, 2012
- CAP 1338553; Failed 21 RHR Pump Shaft Material Inconsistent With OEM Specification; May 21, 2012
- EC 19634; Evaluation of D2 Operability with Low Air Flow Conditions; March 7, 2012
- EC 19885; Past Operability for 2RH-3-2; Revision 0
- ECE 1334924; 21 RHR Pump Equipment Cause Evaluation; No Date
- QF-0573; Issue Discovery Checklist; May 21, 2012
- Veide to Stephens Letter Regarding NRC Bulletin 88-04; July 25, 1988
- Westinghouse Email Correspondence; Chemistry Results – 21 RHR Shaft Failure;

May 24, 2012
- Westinghouse MCOE-TR-12-6; Prairie Island Unit 2 21 RHR Pump Shaft Failure Examination; Revision 0
- WO 455607; Troubleshooting Plan, 21 RHR Pump; April 25, 2012

1R18 Modifications

- Work Plan; Install Spool Piece for Reactor Coolant Gas Vent System Piping Modification; March 28, 2012
- Drawing SK-EU9795-01; EC 19795 - Reactor Coolant Gas Vent System Vent Valve; Revision 0
- EC 19946; Unit 2 RCS Draindown NUE/CAP; Revision 000
- EC 20069; Evaluation of Adverse Slope of Unit 2 Reactor Coolant Gas Vent System Piping; May 16, 2012
- 50.59 Screening 3970; Unit 2 Reactor Head Vent Improvement Modification; Revision 0
- WO 454221-05; U2 Install Valve Spool Piece Assembly; April 11, 2012
- WO 453755-01; Verify No Blockage From 2RC-21-1 Through Spool Piece; May 4, 2012
- Work Plan 453755-01; Verify No Blockage From 2RC-21-1 Through Spool Piece; March 20, 2012
- CAP 1336529; Adverse Slope Found In Unit 2 RCGVS; May 5, 2012
- CAP 1327920; Unidentifed RCS Leakage – Unusual Event; March 6, 2012

1R19 Post Maintenance Testing

- 2M-AF-3132-1-22; Isolation, Restoration and Testing of 22 Aux Feed Pump; Revision 4
- 2M-ZC-274-013; 23 FCU Isolation and Restoration; Revision 3
- C35 AOP4; Cooling Water Leakage In Containment; Revision 17
- CAP 1308058; D1 and D2 Fuse Replacement WOs Have No PMT/RTS Testing; October 13, 2012
- CAP 1320845; Sequencing PMT Could Have Avoided TS 3.0.3 Entry; January 21, 2012
- CAP 1328278; Work Order 443371 – Best Test Replacement VM1; March 8, 2012
- Clearance Order 48837; Replace 23 FCU @ CR-23 End-Bell Gasket; May 22, 2012
- Clearance Order 48842; Protected Equipment for Mode 4 Change, 23 FCU OOS Risk Assessment; May 21, 2012
- Clearance Order 48842; Protected Equipment for Mode 4 Change, 23 FCU OOS Risk Assessment; May 21, 2012
- Drawing NE-40011 Sheet 55; Rev-N Schematic Diagram; February 1, 1999
- Drawing NE-40011 Sheet 56; Rev-N Schematic Diagram; February 1, 1999
- Drawing NE-40011 Sheet 57; Rev-HJ-(47024A) Control Console G-1; February 1, 1999
- Drawing NE-40011 Sheet 58; Rev-HJ-(47024A) Control Console G-1; February 1, 1999
- Drawing NE-40011 Sheet 59; Rev-FG-(47024A)(47024B) Control Console G-1; February 1, 1999
- Drawing NE-40011 Sheet 60; Rev-Z-(47024B) Control Console G-1; April 12, 2001
- Drawing NF-39217-2; Flow Diagram Cooling Water – Aux Bldg Unit 2; Revision 80
- Drawing NF-39217-3; Flow Diagram Cooling Water – Containment Unit 2; Revision 79
- Drawing NF-40269-2; External Connections Annunciator Cabinet 12; February 14, 2001
- Outage Scope Change Request 539; Replace VM1 Voltage Monitor; February 28, 2012
- Outage Scope Change Request Number 833; Bench Test Replacement VMI for Bus 25 Load Sequencer; April 2, 2012
- PM 3154-4-23; 23 Containment Fan Coil Unit Cooling Coil Maintenance and Inspection; Revision 2

- SP 2054; Turbine Stop, Governor, Reheat Stop and Reheat Intercept Valve Exercise; Revision 43
- SP 2102; 22 Turbine-Driven AFW Pump Monthly Test; Revision 92
- SP 2103; 22 Turbine-Driven Auxiliary Feedwater Pump Once Every Refueling Shutdown Flow Test; Revision 49
- SP 2121; 21 Component Cooling Pump Low Pressure/Auto Start Pressure Switch Calibration; Revision 10
- SP 2330; 22 Turbine-Driven AFW Turbine/Pump Bearing Temperature Test; Revision 16
- SP 2371-21; Temporary Procedure for the Cold Shutdown Test of 21 RHR Pump; Revision 5
- SP 2376; AGW Flow Path Verification Test After each Cold Shutdown; Revision 22
- SWI O-200.1; Pre-Job Briefings and Post Job Critiques; Revision 1
- WO 308808; U2, AF-12-4 (AFW to 21 SG Isol) Leaks – 2R27; March 15, 2012
- WO 371272; 22 TDAFWP, Replace Governor Valve Bonnet; April 13, 2012
- WO 375012; SP2054 Turbine Stop, Governor, Reheat Stop and Reheat Intercept Valve Exercise ; May 31, 2012
- WO 395532; MV-32246, 22 AFW to 21 SG MV; April 27, 2012
- WO 409544; PM3132-1-22, 22 TD AFWP Minor Maintenance; May 1, 2012
- WO 409815-01; SP 2121, 21 Component Cooling Pump Low Pressure/Auto Start Pressure Switch Calibration; April 11, 2012
- WO 409835; 22 TDAFW Turbine/Pump Bearing Temp Test; December 09, 2012
- WO 409842; AFW Flow Path Test after Each CSD; July 31, 2010
- WO 414218; SP 2121, 21 Component Cooling Pump Low Pressure/Auto Start Pressure Switch Calibration; April 11,2012
- WO 437629; SP 2102 22 Turbine-Driven AFW Pump Monthly Test; August 12, 2011
- WO 443879-02; Repair Boric Acid Packing Leak on Valve 2RC-8-14; May 23, 2012
- WO 455889-04; Perform Input Checks For Scanner Card #6; April 25, 2012
- WO 455997-11; SP 2371-21 - Temporary Procedure for the Cold Shutdown Test of 21 RHR Pump; April 19, 2012
- WO 460147; 23 FCU @ CR-23 End-Bell Gasket Appears To Be Leaking; May 22, 2012

<u>1R20 Refueling and Outage</u>

- 2R27 Core Inventory DVD; April 17, 2012
- Calculation 2005-05621; Analysis of Postulated Reactor Head Load Drop; April 08, 2005
- CAP 1284232; Incorrect Elev. Specified for Reactor Head Loss Drop Analysis; June 09, 2011
- CAP 1327920; Unidentified RCS Leakage – Unusual Event; March 6, 2012
- CAP 1338009; Work Hour Rules Violation – 72/168; May 17, 2012
- CAP 1342868; Discrepancies Discovered During Time Audit; June 25, 2012
- CN-NR27-008; Westinghouse Prairie Island Unit 2, Cycle 27 Reference Core Loading Pattern; Revision 0
- D58.2.10; Unit 2 Reactor Vessel Head Replacement; Revision 17
- Drawing SK-EU9795-01; EC 19795 - Reactor Coolant Gas Vent System Vent Valve; Revision 0
- EC 19946; Unit 2 RCS Draindown NUE/CAP; Revision 000
- EC 20069; Evaluation of Adverse Slope of Unit 2 Reactor Coolant Gas Vent System Piping; May 16, 2012
- Fatigue Assessment 1141; March 28, 2012
- Fatigue Assessment 1142; March 28, 2012
- FP-PE-III-P8P8-GTSM-062; Groove Welds and Fillet Welds, P8-P8, GTAW/SMAW, Without PWHT; Revision 3

- Individual Work Hours Validation for Randomly Selected Individuals from: Operations; FIN; Fire Brigade; Chemistry; Security; Mechanical Maintenance; I&C; and Electrical Maintenance
- PORC Meeting 3228; Unit 2 Restart Readiness; Various Dates
- RCE 1327920; Unit 2 RCS Unidentified Leakage Greater Than 10 GPM; March 29, 2012
- SP 2070; Reactor Coolant System Integrity Test; Revision 40
- SP 2750; Post Containment Close-Out Inspection; Revision 37
- WCR 454221-06-1; Weld Control Record for 2RC-8-33 / ¾-RC-83; April 4, 2012
- Weld Map 454221-01; Sheet 1; Revision 1
- WO 409996; D58.2.10 Replace Reactor Head per D7 and D58.2.10; May 2, 2012
- WO 453395-01; 1-2RC-83, Measure The Level Change on Reactor Coolant Gas Vent Line; April 2, 2012
- WO 453755-01; Verify No Blockage From 2RC-21-1 Through Spool Piece; May 4, 2012
- WO 454221-05; U2 Install Valve Spool Piece Assembly; April 11, 2012
- Work Plan 453755-01; Verify No Blockage From 2RC-21-1 Through Spool Piece; March 20, 2012
- Work Plan; Install Spool Piece for Reactor Coolant Gas Vent System Piping Modification; March 28, 2012

<u>1R22 Surveillance Test</u>

- CAP 1271370; CV-31153 Timed Outside of its Reference Range; February 17, 2011
- CAP 1286306; Calculation is Non-conservative for AFW Pump IST Acceptance Criteria; September 17, 2011
- CAP 1294772; Diesel Room Heat Up Basis Doesn't Factor in Instrument Inaccuracies; July 15, 2011
- CAP 1305143; SP 2661 Diesel Emergency Shutdowns; September 23, 2011
- CAP 1321862; Inconsistencies Between D5 & D6 Bearing Insulation Test Procedures; January 23, 2012
- CAP 1331946; D6 Control Switch Found Out of Position; April 2, 2012
- SP 1090A; 11 Containment Spray Pump Quarterly Test; Revision 21
- SP 1305; D2 Diesel Generator Monthly Slow Start Test; Revision 43
- SP 2083A; Unit 2 Integrated SI Test with a Simulated Loss of Offsite Power Train A; Revision 0
- SP 2090B; 22 Containment Spray Pump Quarterly Test; Revision 18
- WO 450404-01; SP2083A Unit 2 Integrated SI Test with a Simulated Loss of Offsite Power Train A; May 11, 2012

<u>4OA1 Performance Indicator Verification</u>

- MSPI Derivation Report; High Pressure Safety Injection; April 2011 through March 2012
- MSPI Derivation Report; Residual Heat Removal System; April 2011 through March 2012

<u>4OA2 Identification and Resolution of Problems</u>

- CAP 1331921; Inspection of 22 Diesel Tile Pipe Corrosion Causes Safety Concern; April 2, 2012
- CAP 1332269; 122 Control Room Chiller Oil Sump Temperature Observed At 126F; April 4, 2012
- CAP 1333264; Blank Lines In Completed Work Order From 2010 Found By NRC; April 11, 2012
- CAP 1333294; Fire Detection Zone Map Questions From NRC; April 11, 2012

- CAP 1333633; F5 Appendix F Fire Door Rating Needs Updating; April 13, 2012
- CAP 1335065; RCs Decay Heat Removal Declared Yellow When It Was Green; April 23, 2012
- CAP 1335122; Whistling Noise From Unit Heater 34; April 24, 2012
- CAP 1335175; Actions Not Issued To Track SR 3.0.3 Testing; April 24, 2012
- CAP 1335688; NRC Observation Of Bus 16 Scanner Card Input Checks; April 28, 2012
- CAP 1335892; Potential For Missed Availability Call On 21 RHR Pump; April 30, 2012
- CAP 1337018; Proposed Mining Operation; May 9, 2012
- CAP 1338229; E-Plan – Evaluate HU1.1 EAL Basis For Intent; May 18, 2012
- CAP 1338984; NRC Finding (Green) Logkeeping; May 24, 2012
- CAP 1338994; Observations From NRC Discussion/Walkdown Related To EDMGs; May 24, 2012
- CAP 1340285; EC20069 RCGVS Evaluation Does Not Address All Operability/Functionality; June 5, 2012
- CAP 1342433; USAR Editorial Errors On Accumulator Check Valve Leakage; June 21, 2012
- CAP 1342528; F5 Appendix A Discrepancy Found By NRC During Fire Drill; June 21, 2012
- CAP 1342868; Discrepancies Found During Time Audit; June 25, 2012
- CAP 1343001; LER For Unit 1 Diesel Fuel Oil Storage Requirements Submitted Late; June 26, 2012
- CAP 1343308; Unit 1 EDG Temperature Challenge Not Resolved Before Hot Weather; June 28, 2012
- CAP 1343465; Questions Raised During OPR For D1/D2 Maximum Outside Air Temperature; June 29, 2012

<u>4OA3 Followup of Events and Notices of Enforcement Discretion</u>

- 1C1.4; Unit 1 Power Operation; Revision 53
- 2C1.4; Unit 2 Power Operation; Revision 48
- 21 RHR Motor Data; Bearing Vibrations; April 20-21, 2012
- 21 RHR Overall Vibration Response Spectra; April 19, 2012
- 2R27 PINGP 21 RHR Fact Finding Document; Various Revisions
- C47502; Alarm Response Procedure 47502-0103 (21/22/23 Feedwater Heater Hi Hi Level); Revision 12
- CAP 0855993; Hi Hi Level in 21/22/23 FW Htrs Required Manually Trip of Unit 2; June, 15, 2005
- CAP 1283119; Manual Turbine Trip Required During Unit 1 Shutdown; April 30, 2011
- CAP 1310238; Unit 1 Fuel Oil Calc Error found in Plant Records; October 27, 2012
- CAP 1311417; Fuel Oil Specification and Consumption Issue; November 3, 2011
- CAP 1325119; LER Required, Uni1 FO Inventory Inadequate During Last 3 years; February 15, 2012
- CAP 1325986; U2 Manual Trip due to Hi Hi feedwater levels; February 28, 2012
- CAP 1326556; Adverse Trend identified in repeat events; February 25, 2012
- CAP 1331778; Autostart of 121 MD CLP when shutting down DDCLP per C35; May 31, 2012
- CAP 1334397; Increased Vibes On 21 RHR Pump; April 19, 2012
- CAP12861416; LP Turbine Steam Inlet Temp Control Not Per VTM Shutdown; May 29, 2012
- Comparison of 21 RHR Pump Motor Vibrations Data 3/10/2012 & 4/21/2012, Similar Flow Rates; No Date
- EC-19427; Past Operability Evaluation 1310238-03; January 20, 2012
- ECE 1325986; Unit 2 manual trip in response to 21/22/23 Feedwater Heater High-High Alarm; April 4, 2012
- FP-PA-ARP-01; CAP Action Request Process; Revision 29
- FP-R-LIC-09; Licensee Event Reports; Revision 4

- Operational Logs; April 21-23, 2012
- SP 2089A; Train A RHR Pump and Suction Valve From The RWST Quarterly Test; Revision 18
- SP 2089A; Train A RHR Pump and Suction Valve From The RWST Quarterly Test; Revision 19
- SP 2089A; Train A RHR Pump and Suction Valve From The RWST Quarterly Test; Revision 20
- SP 2092B; Safety Injection Check Valve Test (Head Off) Part B: RWST To RHR Flow Path Verification; Revision 19
- SP 2371; Cold Shutdown Test Of RHR Pumps And Check Valves; Revision 11
- SP 2371; Cold Shutdown Test Of RHR Pumps And Check Valves; Revision 12
- SP 2371; Cold Shutdown Test Of RHR Pumps And Check Valves; Revision 14
- Unit 2 Shutdown Safety Assessment; April 21, 2012
- Unit 2 Shutdown Safety Assessment; April 22, 2012
- Unit 2 Shutdown Safety Assessment; April 23, 2012
- VTM-XH-2-164-1 “572 MW Steam Turbine Operation and Control Manual”; 1996
- WO 447564; SP 2089A; Train A RHR Pump and Suction Valve From The RWST Quarterly Test; May 22, 2012

<u>4OA5 Other Activities</u>

- C18.1; Engineered Safeguards Equipment Support Systems; Revision 30
- CAP 1312835; Rescope all Prairie Island Systems to the Revised Maintenance Rule Guidance; February 28, 2012
- CAP 1337018; Proposed Mining Operation; May 9, 2012
- Control Room Narrative Logs; January 22, 2012
- Piping and Instrumentation Drawing NF-118254; D5 Building Heating, Ventilation and Air Conditioning System Flow Diagram; Revision 77
- TP 2296A; D5 Radiator Fans Weekly Run Test and 2ZGSystem Weekly Damper Cycling; Revision 3
- Various PINGP Emergency Operating Procedures
- Various PINGP EOP Deviation Documents
- WCAP-17433-NP; Pressurized Water Reactor Owners Group Emergency Operating Procedure Maintenance Program Standard; Revision 0
- Westinghouse Owner’s Group Emergency Response Guidelines; Revision. 2

<u>4OA7 Licensee Identified Findings</u>

- CAP 1325986; U2 Manual Reactor Trip Due To HI HI Feedwater Heater Levels; February 22, 2012
- CAP 1335689; Review Commitment 01024151-01 for Reportability; April 28, 2012
- ECE 1325966-03; Equipment Cause Evaluation 2R27 Manual Reactor Trip; March 15, 2013
- L-HU-06-021; Response to NRC Phase 1 Item B.2.m.1 – Spent Fuel Dispersal; April 26, 2006
- SWI NE-8; Generation of Fuel Transfer Log; Revision 24

## LIST OF ACRONYMS USED

| | |
|---|---|
| AC | Alternating Current |
| ADAMS | Agencywide Document Access Management System |
| AOP | Abnormal Operating Procedure |
| ARP | Alarm Response Procedure |
| CAP | Corrective Action Program |
| CC | Component Cooling |
| CFR | Code of Federal Regulations |
| CVCS | Control Volume Control System |
| DDCLP | Diesel Driven Cooling Water Pump |
| EC | Engineering Change |
| EDG | Emergency Diesel Generator |
| EP | Emergency Plan |
| EPRI | Electric Power Research Institute |
| FCU | Fan Coil Unit |
| FIN | Finding |
| IMC | Inspection Manual Chapter |
| INPO | Institute of Nuclear Power Operations |
| IP | Inspection Procedure |
| Ips | Inches per Second |
| IST | Inservice Test |
| LER | Licensee Event Report |
| LERF | Large Early Release Frequency |
| MD | Motor Damper |
| MDCLP | Motor Driven Cooling Water Pump |
| MSPI | Mitigating Systems Performance Index |
| MSR | Moisture Separator Reheater |
| NCV | Non-Cited Violation |
| NEI | Nuclear Energy Institute |
| NRC | U.S. Nuclear Regulatory Commission |
| OOS | Out of Service |
| OPR | Operability Recommendations |
| OSP | Outage Safety Plan |
| PARS | Publicly Available Records System |
| PI | Performance Indicator |
| PM | Post Maintenance |
| PRA | Probabilistic Risk Assessment |
| RFO | Refueling Outage |
| RG | Regulatory Guide |
| RHR | Residual Heat Removal |
| SDP | Significance Determination Process |
| SI | Safety Injection |
| SRA | Senior Risk Analyst |
| SSC | Structures, Systems, and Components |
| TDAFWP | Turbine-Driven Auxiliary Feedwater Pump |
| TS | Technical Specification |
| TSO | Transmission System Operator |
| UFSAR | Updated Final Safety Analysis Report |
| URI | Unresolved Item |

| | |
|---|---|
| USAR | Updated Safety Analysis Report |
| VTM | Vendor Technical Manual |
| WO | Work Order |

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Sincerely,

***/RA/***

Kenneth Riemer, Chief
Branch 2
Division of Reactor Projects

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

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Letter to J. Molden from K. Riemer dated August 9, 2012

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 - NRC INTEGRATED INSPECTION REPORT 05000282/2011005; 05000306/2011003

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