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

July 26, 2010

Mr. Mark A. Schimmel
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 05000282/2010003; 05000306/2010003

Dear Mr. Schimmel:

On June 30, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed a baseline inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the inspection findings, which were discussed on July 8, 2010, 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.

Based on the results of this inspection, one NRC-identified and two self-revealed findings of very low safety significance were identified. Two findings involved a violation of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as non-cited violations (NCVs) in accordance with Section VI.A.1 of the NRC Enforcement Policy.

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

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 Public Document Room or from the Publicly Available Records System (PARS) component of NRC's document 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 by Kenneth Riemer for/

Robert J. Orlikowski, Acting Chief
Branch 4
Division of Reactor Projects

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

Enclosure: Inspection Report 05000282/2010003; 05000306/2010003
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306; 72-010
License Nos:	DPR-42; DPR-60; SNM-2506
Report No:	05000282/2010003; 05000306/2010003
Licensee:	Northern States Power Company, Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, MN
Dates:	April 1 through June 30, 2010
Inspectors:	K. Stoedter, Senior Resident Inspector P. Zurawski, Resident Inspector D. Betancourt, Reactor Engineer L. Haeg, Resident Inspector - Monticello D. Jones, Reactor Inspector R. Langstaff, Senior Fire Protection Inspector R. Lerch, Project Engineer M. Phalen, Health Physics Inspector
Approved by:	R. Orlikowski, Acting Chief Branch 4 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000282/2010003; 05000306/2010003; 4/1/2010 – 6/30/2010; Prairie Island Nuclear Generating Plant, Units 1 and 2; Event Follow-Up.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Two self-revealed and one NRC-Identified Green findings were identified. Two of the findings were considered non-cited violations of NRC regulations. 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 was identified following an automatic reactor trip on April 16, 2010. Specifically, the licensee failed to appropriately establish and implement actions to correct the causes of a turbine trip/reactor trip in 2001 and a turbine trip in 2003 even though the actions were required by the corrective action procedure in use at the time of the event. The failure to appropriately establish and implement actions to correct the causes of the previous events resulted in creating a large difference in Unit 2 condenser pressures while operating at lower power levels and a subsequent turbine trip/reactor trip. Corrective actions for this issue included correcting system deficiencies which led to the large difference in condenser pressures and improving procedural guidance regarding the sealing steam system.

  The inspectors determined that this issue was more than minor because it was associated with the design control, configuration control and procedure quality attributes of the Initiating Events Cornerstone and impacted the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. This finding was determined to be of very low safety significance because it did not contribute to a reactor trip with mitigating equipment not available. No cross-cutting aspect was assigned to this finding because the decisions made in regard to the 2001 and 2003 actions were made more than 2 years ago. No violation of NRC requirements was identified because the system deficiencies that contributed to the turbine trip/reactor trip were associated with non safety-related systems. (Section 4OA3.7)

Cornerstone: Mitigating Systems

- Green. A self-revealed finding of very low safety significance and a non-cited violation of Technical Specification 5.4.1 was identified on April 9, 2010, due to the licensee's failure to implement Step 5.1.1 of Procedure FP-G-DOC-03, "Procedure Use and Adherence." Step 5.1.1 of FP-G-DOC-03 required that personnel perform activities affecting quality using working copies of continuous or reference use procedures. However, operations personnel failed to use a working copy of reference use Procedure C37.13, "Containment and Auxiliary Building Cooling System," when performing valve alignments to support the performance of a surveillance test. The failure to use a working copy of C37.13 resulted in the operator performing a valve alignment incorrectly and a loss of one-half of the Unit 2 containment cooling system. Corrective actions for this issue included restoring the containment cooling system, briefing licensee personnel on the event, and reinforcing the use of the human performance tools.

The inspectors determined that this finding was more than minor because it was associated with the human performance attribute of the Mitigating System Cornerstone and impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that this finding was of very low safety significance because it did not represent a loss of a system safety function, the fan coil units were inoperable for less than the Technical Specification allowed outage time, and the finding was not potentially risk significant due to external events. The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because licensee personnel did not ensure human error prevention techniques were used such that work activities were performed safely (H.4(a)). (Section 4OA3.8)

- Green. A finding of very low safety significance and a non-cited violation of 10 CFR Part 50, Appendix B, Criterion V was identified by the inspectors on March 15, 2010, due to the licensee's failure to have instructions and procedures appropriate to the circumstance for performing Work Order 382152 and Surveillance Procedure 1295, "D1 Diesel Generator 6 Month Fast Start Test." The failure to have instructions and procedures appropriate to the circumstance resulted in rendering the D1 diesel generator inoperable for 28 hours due to the introduction of foreign material into the lube oil sump during oil addition activities. Corrective actions included retrieving the hose and nozzle, replacing the plastic oil cans with new solid metal cans, and revising the pre-job brief instructions and "Are You Ready" checklist to include a question whether foreign material will be generated through the use of portable equipment or tools.

  The inspectors determined that the finding was more than minor because it was associated with the procedure quality and human performance attributes of the Mitigating Systems Cornerstone and impacted the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that this finding was of very low safety significance because it did not represent a loss of a system safety function and the diesel generator was inoperable for less than the Technical Specification allowed outage time. This finding was determined to be cross-cutting in the Human Performance, Work Control area because the licensee failed to appropriately plan work activities by incorporating job site conditions which may impact plant structures, systems, or components (H.3(a)). (Section 4OA3.10)

B. Licensee-Identified Violations

Violations of very low safety significance that 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 corrective action program. 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 full power levels throughout the inspection period.

Unit 2 operated at or near full power levels with the following exceptions:

- In early April, operations personnel began reducing reactor power to perform valve testing prior to the refueling outage.
- On April 16, 2010, the Unit 2 reactor automatically tripped from 13 percent power due to a high differential pressure condition within the main condenser;
- Refueling Outage 2R26 began immediately following the automatic reactor trip on April 16, 2010;
- Operations personnel began Unit 2 startup activities on May 19, 2010;
- The Unit 2 reactor achieved criticality on May 22, 2010;
- On May 25, 2010, the Unit 2 reactor automatically tripped from 31 percent power due to the loss of the 21 feedwater pump;
- The Unit 2 reactor returned to criticality on May 26, 2010.
- Operations personnel identified a primary to secondary leak and entered Abnormal Operating Procedure 2C4 AOP 2, “Steam Generator Tube Leak,” on May 28, 2010.
- Operations personnel returned Unit 2 to 100 percent power on May 31, 2010.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Onsite Alternating Current 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 operations personnel 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 operations personnel when the offsite power system was returned to normal.

The inspectors also verified that plant 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.

Documents reviewed are listed in the Attachment to this report. The inspectors also reviewed corrective action program (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 the corrective action procedures.

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

b. Findings

No findings of significance were identified.

.2 Readiness for Bio-fouling Concerns

a. Inspection Scope

During the week of April 14, 2010, the inspectors observed licensee activities associated with the treatment of raw water systems to control the population of zebra mussels. The inspectors observed pre-job briefings to determine whether the briefings met licensee standards. The inspectors reviewed prerequisites identified in Procedure D104.1, “Zebra Mussel Control Treatment: Circulating Water System,” to determine whether they were completed prior to the initiation of treatment. The inspectors were specifically interested in the licensee’s actions to ensure that the following safety-related equipment was not impacted by mussel settling:

- Diesel-Driven Cooling Water Pump Heat Exchangers, and
- D1 and D2 Diesel Generators.

As the zebra mussel treatment progressed, the inspectors periodically reviewed licensee activities and data collection to determine whether mussel settlement was being properly monitored. The inspectors also reviewed CAP items to verify that the licensee was identifying zebra mussel treatment issues at an appropriate threshold and entering them into the CAP in accordance with procedures. Specific documents reviewed during this inspection are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- Spent Fuel Pool Cooling System;
- 21 Motor-Driven Auxiliary Feedwater (AFW) Pump; and
- D6 Diesel Generator.

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, Updated Safety Analysis Report (USAR), Technical Specification (TS) requirements, outstanding work orders (WOs), CAP documents, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and were operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

.2 Semiannual Complete System Walkdown

a. Inspection Scope

On April 1, 2010, the inspectors performed a complete system alignment inspection of the Unit 2 diesel generator fuel oil system to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment line ups, electrical power availability, system pressure and temperature indications, as appropriate, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings of significance 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 areas:

- Fire Zone 8 - Auxiliary Building Ground Floor;
- Fire Zone 40 - Unit 2 Auxiliary Building 695 Foot Elevation;
- Fire Zone 51 - Auxiliary Building Unit 2 Operating Level Elevation 735;
- Fire Zones 3, 4, and 14 - Unit 1 Turbine Building; and
- Fire Zone 20 - Bus 15 and 16 Switchgear Rooms.

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 with later additional insights and their potential to impact equipment, which could initiate or mitigate a plant transient. 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 five quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings of significance were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

As discussed in NRC Inspection Report (IR) 05000282/2010010; 05000306/2010010, the inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed design documents, including the USAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's CAP documents with respect to past flood-related items to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant area to assess the adequacy of doors and that the licensee complied with its commitments:

- 11, 12, 21, and 22 Battery Rooms.

The documents reviewed during this inspection are listed in the Attachment to NRC IR 05000282/2010010; 05000306/2010010.

This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

A preliminary greater than green finding was identified. See Section 4OA5 of NRC IR 05000282/2010010; 05000306/2010010 for additional details.

1R08 Inservice Inspection Activities (71111.08P)

From April 19 through May 13, 2010, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the reactor coolant system (RCS), steam generator tubes, emergency feedwater systems, risk-significant piping and components and containment systems.

The inspections described in Sections 1R08.1, 1R08.2, 1R08.3, 1R08.4, and 1R08.5 below constituted one ISI sample as defined in IP 71111.08.

.1 Piping Systems Inservice Inspection

a. Inspection Scope

The inspectors observed the following non-destructive examinations mandated by the American Society of Mechanical Engineers (ASME) Section XI Code to evaluate compliance with the ASME Code Section XI and Section V requirements and if any indications and defects were detected, to determine if these were dispositioned in accordance with the ASME Code or an NRC approved alternative requirement.

- Ultrasonic examination of the residual heat removal system elbow to elbow weld 18, Report Number 2010U001; and
- Ultrasonic examination of the residual heat removal system elbow to pipe weld 19, Report Number 2010U002;

The inspectors reviewed records of the following non-destructive examinations:

- Visual examination of the reactor vessel closure head, Report Number PI2RF2010;
- Liquid Penetrant examination of the N2 to Loop B, steam generator reactor coolant pressure boundary isolation, 2RC-8-41, pipe to elbow weld 2; Report Number BOP-PT-08-047; and
- Liquid Penetrant examination of the N2 to Loop B, steam generator reactor coolant pressure boundary isolation, 2RC-8-41, socket weld-pipe to valve weld 8; Report Number BOP-PT-08-051.

During non-destructive surface and volumetric examinations performed since the previous refueling outage, the licensee had not identified any recordable indications. Therefore, no NRC review was completed for this inspection procedure attribute.

The inspectors reviewed the following pressure boundary welds completed for risk-significant systems during the last refueling outage to determine if the licensee applied the pre-service non-destructive examinations and acceptance criteria required by ASME Code Section XI. Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine if the weld procedures were qualified in accordance with the requirements of Construction Code and the ASME Code Section IX.

- ASME Section XI repair/replacement welding of reactor coolant system, ASME Class 1, Valve 2RC-8-41 in N2 to Loop B steam generator reactor coolant pressure boundary isolation, WO 304396.

b. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the Unit 2 reactor vessel head, a bare metal visual examination was required this outage pursuant to 10 CFR 50.55a(g)(6)(ii)(D).

The inspectors reviewed records of the visual examination conducted on the Unit 2 reactor vessel head at penetrations 12, 21, 25, and 33 to determine if the activities were conducted in accordance with the requirements of ASME Code Case N-729-1 and 10 CFR 50.55a(g)(6)(ii)(D). In particular, the inspectors confirmed that:

- the required visual examination scope/coverage was achieved and limitations (if applicable were recorded) in accordance with the licensee procedures;
- the licensee criteria for visual examination quality and instructions for resolving interference and masking issues were adequate; and
- if indications of potential through-wall leakage were identified, the licensee entered the condition into the CAP and implemented appropriate corrective actions.

The licensee did not perform any welded repairs to vessel head penetrations since the beginning of the preceding outage for Unit 2. Therefore, no NRC review was completed for this inspection procedure attribute.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control

a. Inspection Scope

The inspectors performed an independent walkdown of all portions of accessible containment systems, which had received a recent licensee boric acid walkdown and verified whether the licensee's boric acid corrosion control visual examinations emphasized locations where boric acid leaks can cause degradation of safety significant components.

The inspectors reviewed the following licensee evaluations of RCS components with boric acid deposits to determine if degraded components were documented in the CAP. The inspectors also evaluated corrective actions for any degraded RCS components to determine if they met the component ASME Section XI Code.

- Condition Evaluation 1227969, MV-32169 Unit 2 RCS Loop B Cold Leg Residual Heat Removal Injection Motor Valve Boric Acid Evaluation; and
- Condition Evaluation 1195401, 2SI-10-2 Body to Bonnet Gasket Leak Corrosion Evaluation.

The inspectors reviewed the following corrective actions related to evidence of boric acid leakage to determine if they were consistent with the requirements of the ASME Code Section XI and 10 CFR Part 50, Appendix B, Criterion XVI.

- 21 Boric Acid Transfer Pump Shut Down Due to Seal Leakage; WO 386738; and
- Boric Acid on 21/22 Residual Heat Removal Heat Exchanger Outlet Flow Element Flange; WO 386836.

b. Findings

No findings of significance were identified.

.4 Steam Generator Tube Inspection Activities

a. Inspection Scope

The NRC inspectors observed acquisition of eddy current (ET) data, interviewed ET data analysts, and reviewed documentation related to the steam generator (SG) ISI program to determine if:

- in-situ SG tube pressure testing screening criteria used were consistent with those identified in the Electric Power Research Institute (EPRI) TR-107620, "Steam Generator In-Situ Pressure Test Guidelines," and that these criteria were properly applied to screen degraded SG tubes for in-situ pressure testing;
- in-situ pressure test records demonstrated pressure and hold times consistent with EPRI TR-107620;
- in-situ pressure test results were properly applied to SG tube integrity performance criteria identified in EPRI TR-107621;
- the numbers and sizes of SG tube flaws/degradation identified was bound by the licensee's previous outage Operational Assessment predictions;
- the SG tube ET examination scope and expansion criteria were sufficient to meet the TSs, and EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 6;
- the SG tube ET examination scope included potential areas of tube degradation identified in prior outage SG tube inspections and/or as identified in NRC generic industry operating experience applicable to these SG tubes;
- the licensee identified new tube degradation mechanisms and implemented adequate extent of condition inspection scope and repairs for the new tube degradation mechanism;
- the licensee implemented repair methods which were consistent with the repair processes allowed in the plant TS requirements and to determine if qualified depth sizing methods were applied to degraded tubes accepted for continued service;
- the licensee implemented an inappropriate "plug on detection" tube repair threshold (e.g., no attempt at sizing of flaws to confirm tube integrity);
- the primary-to-secondary leakage (e.g., SG tube leakage) was below 3 gallons per day or the detection threshold during the previous operating cycle;
- the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, "Performance Demonstration for Eddy Current Examination," of EPRI 1003138, Revision 6; and
- the licensee performed secondary side SG inspections for location and removal of foreign materials.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI/SG related problems entered into the licensee's CAP and conducted interviews with licensee staff to determine if:

- the licensee had established an appropriate threshold for identifying ISI/SG related problems;
- the licensee had performed a root cause (if applicable) and taken appropriate corrective actions; and
- the licensee had evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity.

The inspectors performed these reviews to evaluate compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On April 6, 2010, the inspectors observed a crew of licensed operators in the simulator during licensed operator training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

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

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 of significance 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:

- Steam Exclusion System; and
- External Circulating Water 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/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 of significance 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:

- emergent work on multiple diesel generators and the potential impact on spent fuel pool cooling functionality;
- delays in returning the blue channel of over power delta temperature to service following an unexpected channel failure;
- emergent work on the Unit 1 AFW system due to an unexpected regulating valve failure;
- emergent work on the Unit 2 residual heat removal system due to a surveillance testing failure;
- unplanned Orange Shutdown Safety Assessment due to the RCS not being intact when expected; and
- emergent work associated with the breaker for the D5 and D6 fuel oil transfer pumps.

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.

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

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- CAP 1207232; Load Sequencer Alarm Sensing Capabilities with Laptop;

- CAP 1226049; Low Wall Thickness Found on Line 24-CL-13;
- CAP 1229117; Pressurizer Power-Operated Relief Valve Isolation Valve Dual Indication;
- CAP 1231470; Cooling Water System Piping Below Minimum Wall in Two Locations;
- CAP 1233935; Potential Common-mode Failure of Unit 2 Fuel Oil Transfer Pumps; and
- CAP 1230668; Unit 1 Safeguard Bus Source Breakers.

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 of significance were identified.

1R18 Plant Modifications (71111.18)

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary modification:

- Temporary Air Compressor for Service Air System (EC 12617)

The inspectors compared the temporary configuration change and associated 10 CFR 50.59 screening and evaluation information 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 also compared the licensee's information to operating experience information to ensure that lessons learned from other utilities had been incorporated into the licensee's decision to implement the temporary modification. The inspectors, as applicable, performed field verifications to ensure that the modification was installed as directed; the modification operated as expected; modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modification did not impact the operability of any interfacing systems. Lastly, the inspectors discussed the temporary modification with operations, engineering, and training personnel to ensure that the individuals were aware of how extended operation with the temporary 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 temporary modification sample as defined in IP 71111.18-05.

b. Findings

No findings of significance were identified.

.2 Permanent Plant Modifications

a. Inspection Scope

The following engineering design package was reviewed and selected aspects were discussed with engineering personnel:

- Generic Letter (GL) 2008-01, Vent Valve Modification for Emergency Core Cooling System (ECCS) Piping in Unit 2.

This document and related documentation were reviewed for adequacy of the associated 10 CFR Part 50.59 safety evaluation screening, consideration of design parameters, implementation of the modification, post-modification testing, and relevant procedures, design, and licensing documents were properly updated. The inspectors observed ongoing and completed work activities to verify that installation was consistent with the design control documents. The modification was completed in response to GL 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems." This modification will help prevent the accumulation of gas voids in the Safety Injection, Residual Heat Removal, and Containment Spray Systems. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

This inspection constituted one permanent plant modification samples as defined in IP 71111.18-05.

b. Findings

No findings of significance were identified.

.3 Permanent Plant Modifications Associated with Temporary Instruction 2515/177, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems”

a. Inspection Scope

As discussed in Section 1R18.2 above, the following engineering design package associated with the scope of GL 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems,” was reviewed and selected aspects were discussed with engineering personnel:

- EC 13483; GL 2008-01 Vent Valve Modification for ECCS Piping in Unit 2.

The inspectors verified that the licensing basis verification documents were updated or were in the process of being updated to reflect the modifications associated with the licensee’s resolution of GL 2008-01 (Temporary Instruction (TI) 2515/177, Section 04.01). The verified documents included TS, TS Bases, USAR, and licensee controlled documents and bases, such as the Technical Requirements Manual.

In addition, the inspectors verified that the drawings were up-to-date with respect to recent hardware changes and that any discrepancies between as-built configurations and the drawings were documented and entered into the corrective action program for resolution (TI 2515/177, Section 04.02.a.6).

Similarly, the inspectors verified that Piping and Instrumentation Diagrams accurately described the subject systems, that they were up-to-date with respect to recent hardware changes, and any discrepancies between as-built configurations, the isometric drawings, and the Piping and Instrumentation Diagrams were documented and entered into the CAP for resolution (TI 2515/177, Section 04.02.b).

Documents reviewed are listed in the Attachment to this report.

This inspection effort counts towards the completion of TI 2515/177, which will be closed in a later Inspection Report.

b. Findings

No findings of significance 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:

- Various procedures following D5 diesel generator refueling outage maintenance;
- Surveillance Procedure (SP) 2073A; Monthly Train A Shield Building Ventilation System Test following maintenance on a shield building ventilation damper;

- D6 break-in run after maintenance;
- SP 2102; 22 Turbine-Driven AFW Pump Monthly Test;
- SP 2331; 21 Motor-Driven AFW Pump Auto Start and Functional Testing Each Refueling Shutdown; and
- Various vent valve locations; GL 2008-01, Vent Valve Modification for ECCS Piping in Unit 2.

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 TS, 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 six post-maintenance testing samples as defined in IP 71111.19-05.

b. <u>Findings</u>

No findings of significance were identified.

1R20 <u>Outage Activities</u> (71111.20)

.1 <u>Refueling Outage Activities</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 2 refueling outage (RFO), conducted April 16 through May 22, 2010, 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 observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below. Documents reviewed during the inspection are listed in the Attachment to this report.

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the 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;
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- 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;
- Refueling activities;
- Startup and ascension to full power operation;
- Tracking of startup prerequisites and a walkdown of the primary containment to verify that debris had not been left which could block ECCS suction strainers; and
- Licensee identification and resolution of problems related to RFO activities.

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

b. Findings

No findings of significance were identified.

.2 Refueling Cavity Leakage

a. Inspection Scope

Over the past 7 months both units have undergone refueling outages. During each outage, the inspectors have monitored licensee actions to resolve refueling cavity leakage. As part of outage activities, the licensee implemented measures to resolve the leakage through weld repairs to susceptible leakage areas in the lower portion of the cavity. Primary repair areas included the internals stands and the change fixture supports. As a result of these repairs, the licensee estimated the leakage had been reduced by approximately 95 percent. Following the 2R26 weld repairs and cavity flood-up, the licensee noted leakage into Sump C. Additionally, the licensee identified an approximate 0.8 gallon per hour (gph) leak into Sump B during the few days following the cavity flood-up. This leak diminished to 0.02 gph four days after the cavity flood-up. The licensee intended to continue monitoring outage related cavity leakage with specific focus on the sealing of sand plug covers. As part of the first refueling outage following refueling cavity leak repairs for each unit, the licensee planned to evaluate the condition of the containment pressure vessel, concrete, and rebar through a small excavation in Sump C. Additionally, concrete degradation will be assessed by obtaining a concrete sample from a location known to have been wetted by borated water leakage from the refueling cavity. These upcoming evaluations were part of the licensee’s license renewal commitments. Previous evaluations have not revealed any degradation of the containment pressure vessel, concrete, or rebar due to refueling cavity leakage.

This activity was conducted as part of the normal baseline activities discussed in Section 1R20.1 of this report and therefore, was not considered an inspection sample.

b. Findings

No findings of significance were identified.

.3 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for an unplanned outage that began following an automatic reactor trip on May 25, 2010, and continued through May 26, 2010. The inspectors reviewed activities to ensure that the licensee considered risk in implementing the outage schedule.

The inspectors observed or reviewed outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, startup and heatup activities, and identification and resolution of problems associated with the outage.

This inspection constituted one other outage sample as defined in IP 71111.20.

b. Findings

No findings of significance 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 2314; 22 Battery Refueling Outage Discharge Test (routine);
- SP 1090B; 12 Containment Spray Pump Quarterly Test (inservice testing);
- SP 1094; Bus 15 Load Sequencer Test (routine);
- SP 2277; General Examination of the Containment Liner for ASME Subsection IWE (routine);
- SP 2431; Main Steam Safety Valve Test (Power Operation) (routine);
- SP 2083; Unit 2 Integrated SI Test With a Simulated Loss of Offsite Power (containment isolation valve);
- SP 2070; Reactor Coolant System Integrity Test (reactor coolant system).

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, demonstrate 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 were 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 ASME Section XI and reference values were consistent with the system design basis;
- were applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- were applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- were 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 four routine surveillance testing samples, one inservice testing sample, one RCS leak detection inspection sample, and one containment isolation valve sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

.1 Training Observation

a. Inspection Scope

The inspector observed a simulator training evolution for licensed operators on April 6, 2010, which required emergency plan implementation by a licensee operations crew. This evolution was planned to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that the licensee evaluators noted the same issues and entered them into the corrective action program. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the Attachment to this report.

This inspection of the licensee's training evolution with emergency preparedness drill aspects constituted one sample as defined in IP 71114.06-05.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstones: Public and Occupational Radiation Safety

2RS8 Radioactive Solid Waste, Processing and Radioactive Material Handling, Storage, and Transportation (71124.08)

This inspection constituted one radioactive solid waste processing and radioactive material handling, storage, and transportation sample as defined in IP 71124.08-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the solid radioactive waste system description in the USAR, the Process Control Program (PCP), and the recent radiological effluent release report for information on the types, amounts, and processing of radioactive waste disposed.

The inspectors reviewed the scope of any quality assurance audit in this area since the last inspection to gain insights into the licensee's performance and inform the "smart sampling" inspection planning.

b. Findings

No findings of significance were identified.

.2 Radioactive Material Storage (02.02)

a. Inspection Scope

The inspectors selected three areas where containers of radioactive waste are stored, and evaluated whether the containers were labeled in accordance with 10 CFR 20.1904, "Labeling Containers," or controlled in accordance with 10 CFR 20.1905, "Exemptions to Labeling Requirements," as appropriate.

The inspectors assessed whether the radioactive materials storage areas were controlled and posted in accordance with the requirements of 10 CFR Part 20, "Standards for Protection Against Radiation." For materials stored or used in the controlled or unrestricted areas, the inspectors evaluated whether they were secured against unauthorized removal and controlled in accordance with 10 CFR 20.1801, "Security of Stored Material," and 10 CFR 20.1802, "Control of Material Not in Storage," as appropriate.

The inspectors evaluated whether the licensee established a process for monitoring the impact of long term storage (e.g., buildup of any gases produced by waste decomposition, chemical reactions, container deformation, loss of container integrity, or re-release of free-flowing water) that was sufficient to identify potential unmonitored, unplanned releases or nonconformance with waste disposal requirements.

The inspectors selected six containers of stored radioactive materials, and assessed them for signs of swelling, leakage, and deformation.

b. Findings

No findings of significance were identified.

.3 Radioactive Waste System Walkdown (02.03)

a. Inspection Scope

The inspectors walked down accessible portions of selected radioactive waste processing systems to assess whether the current system configuration and operation agreed with the descriptions in the USAR, offsite dose calculation manual, and PCP.

The inspectors reviewed administrative and/or physical controls (i.e., drainage and isolation of the system from other systems) to assess whether the equipment which was not-in-service or abandoned in place would not contribute to an unmonitored release path and/or affect operating systems or be a source of unnecessary personnel exposure. The inspectors assessed whether the licensee reviewed the safety significance of systems and equipment abandoned in place in accordance with 10 CFR Part 50.59, "Changes, Tests, and Experiments."

The inspectors reviewed the adequacy of changes made to the radioactive waste processing systems since the last inspection. The inspectors evaluated whether changes from what was described in the USAR were reviewed and documented in accordance with 10 CFR Part 50.59, as appropriate and to assess the impact on radiation doses to members of the public.

The inspectors assessed whether the waste stream mixing, sampling procedures, and methodology for waste concentration averaging were consistent with the PCP, and provided representative samples of the waste product for the purposes of waste classification as described in 10 CFR Part 61.55, “Waste Classification,” for selected waste processes.

The inspectors evaluated whether the tank recirculation procedures provided sufficient mixing for systems that provide tank recirculation.

The inspectors assessed whether the licensee’s PCP correctly described the current methods and procedures for dewatering and waste stabilization (e.g., removal of freestanding liquid).

b. Findings

No findings of significance were identified.

.4 Waste Characterization and Classification (02.04)

a. Inspection Scope

The inspectors selected the following radioactive waste streams for review:

- Dry Active Waste (DAW);
- High Level Resin; and
- Low Level Filters.

For the waste streams listed above, the inspectors assessed whether the licensee’s radiochemical sample analysis results (i.e., “10 CFR Part 61” analysis) were sufficient to support radioactive waste characterization as required by 10 CFR Part 61, “Licensing Requirements for Land Disposal of Radioactive Waste.” The inspectors evaluated whether the licensee’s use of scaling factors and calculations to account for difficult-to-measure radionuclides was technically sound and based on current 10 CFR Part 61 analyses for the selected radioactive waste streams.

The inspectors evaluated whether changes to plant operational parameters were taken into account to: (1) maintain the validity of the waste stream composition data between the annual or biennial sample analysis update; and (2) assure that waste shipments continued to meet the requirements of 10 CFR Part 61 for the waste streams selected above.

The inspectors evaluated whether the licensee had established and maintained an adequate Quality Assurance program to ensure compliance with the waste classification and characterization requirements of 10 CFR 61.55 and 10 CFR 61.56, “Waste Characteristics.”

b. Findings

No findings of significance were identified.

.5 Shipment Preparation (02.05)

a. Inspection Scope

The inspectors observed shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and licensee verification of shipment readiness. The inspectors assessed whether the requirements of applicable transport cask certificate of compliance had been met. The inspectors evaluated whether the receiving licensee was authorized to receive the shipment packages. The inspectors evaluated whether the licensee's procedures for cask loading and closure procedures were consistent with the vendor's current approved procedures.

The inspectors observed radiation workers during the conduct of radioactive waste processing and radioactive material shipment preparation and receipt activities. The inspectors assessed whether the shippers were knowledgeable of the shipping regulations and whether shipping personnel demonstrated adequate skills to accomplish the package preparation requirements for public transport with respect to:

- the licensee's response to NRC Bulletin 79-19, "Packaging of Low-Level Radioactive Waste for Transport and Burial," dated August 10, 1979; and
- Title 49 CFR Part 172, "Hazardous Materials Table, Special Provisions, Hazardous Materials Communication, Emergency Response Information, Training Requirements, and Security Plans," Subpart H, "Training."

Additionally, due to limited opportunities for direct observation, the inspectors reviewed the technical instructions presented to workers during routine training. The inspectors assessed whether the licensee's training program provided training to personnel responsible for the conduct of radioactive waste processing and radioactive material shipment preparation activities.

b. Findings

No findings of significance were identified.

.6 Shipping Records (02.06)

a. Inspection Scope

The inspectors evaluated whether the shipping documents indicated the proper shipper name; emergency response information and a 24-hour contact telephone number; accurate curie content and volume of material; and appropriate waste classification, transport index, and UN number for the following radioactive shipments:

- Shipment Number 09-024; Hn-215 Cask – Dewatered Resin; November 2009;
- Shipment Number 09-025; Hn-215 Cask – Dewatered Resin; November 2009;
- Shipment Number 09-030; DAW Sealands; December 2009;
- Shipment Number 10-005; DAW Sealands; January 2010; and
- Shipment Number 10-008; DAW Sealands; February 2010.

Additionally, the inspectors assessed whether the shipment placarding was consistent with the information in the shipping documentation.

b. Findings

No findings of significance were identified.

.7 Identification and Resolution of Problems (02.07)

a. Inspection Scope

The inspectors assessed whether problems associated with radioactive waste processing, handling, storage, and transportation, were being identified by the licensee at an appropriate threshold, were properly characterized, and were properly addressed for resolution in the licensee's CAP. Additionally, the inspectors evaluated whether the corrective actions were appropriate for a selected sample of problems documented by the licensee that involve radioactive waste processing, handling, storage, and transportation.

The inspectors reviewed results of selected audits performed since the last inspection of this program and evaluated the adequacy of the licensee's corrective actions for issues identified during those audits.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS leakage performance indicator (PI) for Units 1 and 2 for the period of the second quarter 2009 through the first quarter of 2010. To determine the accuracy of the PI data reported during those periods, PI guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, was used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, CAPs, event reports and NRC Integrated Inspection Reports for the period listed above to validate the accuracy of the submittals. The inspectors also reviewed the licensee's corrective action system to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two RCS leakage samples as defined in IP 71151-05.

b. Findings

No findings of significance 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: the complete and accurate identification of the problem; that timeliness was commensurate with the safety significance; that 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 attached List of Documents Reviewed.

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 of significance 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 licensee's daily condition report packages.

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

b. Findings

No findings of significance were identified.

.3 Semiannual 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 period of December 2009 through June 2010 although some examples expanded beyond those dates where the scope of the trend warranted.

The review also included issues documented outside the normal CAP in system health reports, quality assurance audit/surveillance reports, self assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's CAP trending reports. 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 of significance were identified.

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

.1 Retraction of Event Notification 45855: Limiting Condition for Operation 3.0.3 Entry and Loss of Safety Function Due to Loss of Turbine Building High Energy Line Break Compensatory Measure

a. Inspection Scope

The inspectors reviewed the event notification, the notification retraction, a supplemental engineering change, and discussed the event notification with operations personnel to determine whether the licensee's retraction was performed in accordance with NRC requirements. Documents reviewed in this inspection are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

.2 (Closed) Licensee Event Report 05000282/2009-006-00: Unanalyzed Condition Due to Potential Safety System Susceptibility to Turbine Building Flooding Due to a Postulated High Energy Line Break

a. Inspection Scope

This Licensee Event Report (LER) discussed the potential for turbine building flooding to occur following a high energy line break. The licensee postulated that the subsequent turbine building flooding may be sufficient to impact the safety function of multiple safety-related systems. The details of this LER, and the inspectors review of this issue, were documented in NRC IR 05000282/2010010; 05000306/2010010 as a potentially greater than Green finding. The documents reviewed are listed in IR 2010010.

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

b. Findings

One potentially greater than Green finding was identified. See IR 05000282/2010010; 05000306/2010010 for additional details. This LER is closed.

.3 (Closed) Licensee Event Report Supplement 05000282/2009-006-01: Unanalyzed Condition Due to Potential Safety System Susceptibility to Turbine Building Flooding Due to a Postulated High Energy Line Break

a. Inspection Scope

This LER provided supplemental information regarding the licensee's review of the potential for turbine building flooding to occur following a high energy line break. The inspectors discussed the supplemental information with engineering and operations personnel as part of an inspection documented in NRC IR 05000282/2010010; 05000306/2010010. The documents reviewed are listed in IR 2010010.

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

b. Findings

One potentially greater than Green finding was identified.
See NRC IR 05000282/2010010 for additional details. This LER is closed.

.4 (Closed) Licensee Event Report 05000306/2010-001-00: Unit 2 Turbine Trip During Reactor Shutdown Resulting in a Reactor Scram

a. Inspection Scope

This LER provided information regarding the reactor trip discussed in Section 4OA3.7 of this inspection report. No new information was provided in this LER.

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

b. Findings

See Section 4OA3.7 of this report for finding details. This LER is closed.

.5 (Closed) Licensee Event Report 05000282/2010-002-00: Postulated Flooding of Unit 1 Fuel Oil Transfer Pump Motor Starters Could Have Resulted in Reduced Fuel Oil Inventory

a. Inspection Scope

This LER documented a condition where the motor starters for the diesel-driven cooling water fuel oil transfer pumps could have been rendered inoperable by an internal flood in the plant screenhouse. The inspectors reviewed the information provided in the LER and compared this information with the inspection item documented in Section 1R06.1 of NRC IR 05000282/2010002; 05000306/2010002 to ensure that no new information was provided.

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

b. Findings

An inspector-identified Green NCV was identified in Section 1R06.1 of NRC IR 05000282/2010002; 05000306/2010002. This LER is closed.

.6 Failure of D6 Direct Current Breaker 8/WCS1/D6

a. Inspection Scope

The inspectors observed the licensee's maintenance plan and troubleshooting efforts associated with finding direct current breaker 8/WCS1/D6 in a tripped condition. The inspectors' efforts included discussing the issue with operations, engineering, and maintenance personnel, reviewing drawings and design basis information, and reviewing the licensee's repair plan to ensure that the maintenance activity was performed in accordance with regulatory requirements.

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

b. Findings

No findings of significance were identified.

.7 Unit 2 Reactor Trip on April 16, 2010

a. Inspection Scope

The inspectors observed operations personnel in the control room, reviewed procedures, strip chart records, sequence of event logs, narrative logs and emergency response computer system data, and held discussions with licensee personnel to determine the cause of a Unit 2 automatic reactor trip. The inspectors also used this information to determine whether operations personnel had responded appropriately following the reactor trip.

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

b. Findings

Introduction: A self-revealed finding of very low safety significance was identified following a Unit 2 automatic reactor trip on April 16, 2010. Specifically, the licensee failed to appropriately establish and implement actions to address previous events in 2001 and 2003. As a result, several of the actions to address these events were not completed. This resulted in a sequence of events that led to a turbine trip and a reactor trip.

Description: At 7:00 p.m. on April 16, 2010, operations personnel began lowering Unit 2 reactor power in preparation for beginning Refueling Outage 2R26. At 10:34 p.m., the Unit 2 reactor automatically tripped from 13 percent power. The inspectors were in the control room when the trip occurred. The inspectors observed operations personnel respond to the reactor trip condition. No issues were identified.

The licensee initiated CAP 1227647 to document the reactor trip. The licensee also completed a root cause evaluation of this event. The licensee determined that the Unit 2 reactor trip occurred because the slope of the sealing steam line to the moisture separator reheater (MSR) safety valves on the south side of the Unit 2 turbine allowed a buildup of condensation that eventually blocked the flow of sealing steam. The lack of sealing steam to the MSR safety valves as the MSR shell became sub-atmospheric, allowed the MSR safety valves to partially open. The partially open safety valves caused a rapid reduction in condenser vacuum. Once the difference in vacuum between the condensers exceeded a specific level an automatic trip signal was sent to the turbine and the reactor.

The licensee also identified the following contributing causes:

- inadequate procedural guidance for aligning gland sealing steam and air ejectors to the heating steam system prior to a large power reduction;
- inadequate procedural guidance regarding the maintenance of gland sealing steam pressure when the system is aligned to the heating steam system;
- inadequate alarm response guidance for addressing high air ejector flow rates;
- degraded gland seal segments on low pressure turbine 2; and
- inadequate corrective action for previous similar events.

The inspectors reviewed the licensee’s corrective action system and found that a similar event had occurred in 2001 and 2003. Specifically on May 9, 2001, Unit 2 experienced a manual turbine trip and reactor trip after experiencing a high differential pressure condition between the two condensers. The licensee determined that this event likely occurred due to air leakage through the MSR relief valves to the condensers due to inadequate sealing steam pressure. Unit 2 also experienced an automatic turbine trip on September 12, 2003, due to air in-leakage caused by steam inlet pressure to the low pressure turbine becoming sub-atmospheric. Corrective actions for the 2001 event included identifying operational requirements or modifications needed to provide adequate sealing steam pressure to the MSRs and changing operating procedures to ensure that adequate guidance was provided to prevent high air leakage flows from flooding the air ejectors. No evidence could be found to show that these actions were taken.

The licensee conducted an equipment investigation of the 2003 event and recommended that the slope of the sealing steam lines to the MSR safety valve headers be verified. Another recommendation was made regarding the need to install more appropriate steam traps on the sealing steam lines. The inspectors found that the licensee had not considered these recommendations to be corrective actions because this event had not caused a reactor trip. This was contrary to the requirements of FP-PA-ARP-01, "Action Request Process," Revision 1 (the revision in place in 2003) which required that the 2003 event be classified as a significance level B condition. This procedure also required that significance level B conditions have actions established and implemented to correct the condition. Lastly, the inspectors found documentation from 2004 showing that the recommendations from the 2003 event became focused on the steam trap installation. As a result, actions to verify the slope of the sealing steam lines were not completed.

Analysis: The inspectors determined that the failure to appropriately establish and implement actions to address the previous turbine trip and/or reactor trip events in 2001 and 2003 was a performance deficiency that required a Significance Determination Process (SDP) evaluation. The inspectors determined that this finding impacted the Initiating Events Cornerstone. The inspectors determined that this finding was more than minor because it was associated with the design control, configuration control, and procedure quality attributes of the Initiating Events Cornerstone and impacted the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. This finding was determined to be of very low safety significance in accordance with IMC 0612 "Significance Determination Process" Attachment 4 Table 4a, because it did not contribute to a reactor trip with mitigating equipment not available. This finding was not cross-cutting because decisions regarding the 2001 corrective actions and the 2003 recommendations were made more than two years ago. (Finding (FIN) 05000306/2010003-01: Failure to Address Design Vulnerability Results in Reactor Trip).

Enforcement: No violations of NRC requirements were identified since the sealing steam system and the MSR safety valves were non-safety related. Corrective actions for this event included revising the appropriate gland sealing steam and alarm response procedures, repairing the gland seal segments on the low pressure turbine, and correcting the slope of the gland seal piping.

.8 Failure to Implement Procedure Use and Adherence Requirements Results in Partial Loss of Containment Cooling

a. Inspection Scope

The inspectors reviewed operator logs and corrective action documentation to determine the sequence of events that led to a partial loss of Unit 2 containment cooling on April 9, 2010.

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

b. Findings

Introduction: A self-revealed finding of very low safety significance and an NCV of TS 5.4.1 was identified on April 9, 2010, due to operations personnel failing to implement requirements designated in Procedure FP-G-DOC-03, "Procedure Use and Adherence." This resulted in an operator failing to use Procedure C37.13, "Containment and Auxiliary Building Cooling System," during system alignments for the 22/24 fan coil unit valve stroke test and a partial loss of Unit 2 containment cooling.

Description: On April 9, 2010, operations personnel were scheduled to perform SP 2245B, "22/24 Fan Coil Unit Valve Stroke Test." Prior to performing this test, operations personnel needed to perform valve alignments using Procedure C37.13. These valve alignments included the opening of two manual valves to ensure that cooling water to the 22 and 24 fan coil units was not lost during the performance of SP 2245B. As operations personnel began performing SP 2245B, cooling water to the 22 and 24 fan coil units was unexpectedly lost. This resulted in a loss of one half of the cooling capacity for the Unit 2 containment building. Control room personnel quickly restored the fan coil unit valve alignment, which allowed the restoration of cooling to the Unit 2 containment.

Step 5.1.1 of Procedure FP-G-DOC-03 required that personnel use working copies of continuous or reference use procedures when performing activities affecting quality. Procedure C37.13 directed activities affecting quality and was designated as a reference use procedure. However, the operator performing the valve alignment reviewed but did not print a copy of Procedure C37.13 for use at the work location. Additionally, the licensee's evaluation concluded the operator had performed the system alignment a number of times and over-confidence was involved in the operator's decision to perform the task without the procedure. Due to the lapse in procedure usage, the two manual valves required to be open were overlooked as part of the alignment process.

Analysis: The inspectors concluded that the failure to follow Step 5.1.1 of Procedure FP-G-DOC-03 and use Procedure C37.13 for the system alignment was a performance deficiency that required an evaluation using the SDP. The inspectors determined that this finding was more than minor because the finding associated with the human performance attribute of the Mitigating Systems Cornerstone and impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that this finding was of very low safety significance in accordance with IMC 0612 "Significance Determination Process" Attachment 4 Table 4a, because it did not represent a loss of a system safety function and the fan coil units were inoperable for less than the TS allowed outage time. The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because licensee personnel did not ensure human error prevention techniques were used such that work activities were performed safely (H.4(a)).

Enforcement: Technical Specification 5.4.1 requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978.

Section 1.d of Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, requires that written procedures be established, implemented and maintained regarding procedural adherence.

Procedure FP-G-DOC-03, "Procedure Use and Adherence," was the licensee's procedure used to implement the requirements of Regulatory Guide 1.33, Section 1.d and TS 5.4.1.

Step 5.1.1 of Procedure FP-G-DOC-03 stated that all personnel shall perform activities affecting quality using working copies of continuous or reference use procedures.

Procedure C37.13, “Containment and Auxiliary Building Cooling System,” directed activities affecting quality and was designated as a reference use procedure.

Contrary to the above, on April 9, 2010, operations personnel failed to implement the procedure use and adherence requirements designated in Procedure FP-G-DOC-03. Specifically, the operators failed to use a working copy of reference use procedure C37.13, an activity affecting quality, while performing a system alignment. This resulted in the failure to manipulate two valves and a partial loss of Unit 2 containment cooling. However, because this violation was of very low safety significance and was entered into your corrective action program as CAP 1226738, it was treated as an NCV consistent with Section VI.A.1 of the Enforcement Policy (NCV 05000306/2010003-02; Lack of Operator Procedure Use During System Alignment). Corrective actions for this issue included the completion of a human performance event investigation, briefing plant personnel on the details of this event, and reinforcing the expectation to use the human performance tools.

.9 Unit 2 Automatic Reactor Trip Due to the Loss of Operating Feedwater Pump

a. Inspection Scope

The inspectors responded to the control room, attended meetings, reviewed the licensee’s post-trip report, and monitored the licensee’s troubleshooting efforts to determine the cause of a Unit 2 automatic reactor trip from 33 percent power on May 25, 2010.

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

b. Findings

Introduction: One unresolved item was identified.

Description: During Unit 2 power ascension activities on May 25, 2010, operations personnel experienced an automatic reactor trip from 33 percent power. The inspectors observed the operators’ response to the event and reviewed the licensee’s post-trip report. The inspectors preliminarily determined that the Unit 2 reactor automatic trip was caused by an unexpected turbine trip. The turbine trip was caused by the unexpected shut down of the operating feedwater pump. The licensee conducted troubleshooting activities and determined that the feedwater pump shut down after receiving a low suction pressure signal. The low suction pressure signal was caused by components inside a pressure switch becoming disconnected. The licensee subsequently replaced the pressure switch. The licensee also inspected several other pressure switches to ensure that the internal components would remain connected during plant operation. The cause of the internal components becoming disconnected remained under review at the conclusion of the inspection period. As a result, the inspectors were unable to determine whether a performance deficiency resulted in the unexpected feedwater pump shutdown and the reactor trip. This issue was determined to be unresolved pending the inspectors’ review of the licensee’s corrective action evaluation. (Unresolved Item (URI) 05000306/2010003-03; Review Licensee’s Evaluation to Determine Whether Performance Deficiency Existed).

.10 Introduction of Foreign Material Renders Diesel Generator Inoperable

a. Inspection Scope

The inspectors reviewed applicable procedures and CAP documents to determine the sequence of events that resulted in introducing foreign material into the D1 lube oil sump.

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

b. Findings

Introduction: A finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion V was identified by the inspectors on March 15, 2010, due to the licensee's failure to have instructions and procedures appropriate to the circumstance for performing WO 382152 and SP 1295, "D1 Diesel Generator 6 Month Fast Start Test." The failure to have instructions and procedures appropriate to the circumstance resulted in rendering the D1 diesel generator inoperable for 28 hours due to the introduction of foreign material into the lube oil sump during oil addition activities.

Description: On March 15, 2010, the licensee implemented WO 382152 which directed the performance of surveillance procedure SP 1295. Step 3.7 of SP 1295 directed operations personnel to check the engine oil level using the dipstick. If the oil level was low, the SP directed the operators to add oil as necessary. The operators determined that approximately 20 gallons of oil needed to be added. After adding about 5 gallons of oil using a 1 gallon oil safe container, the container's tube and nozzle became disconnected and fell into the lube oil sump. The introduction of this foreign material (the tube and nozzle) into the sump rendered the D1 diesel generator inoperable until the material was retrieved. The licensee initiated CAP 1222649 to document this issue.

The inspectors reviewed the licensee's apparent cause investigation report for this event. The licensee determined that the foreign material was introduced into the D1 lube oil sump because operations personnel failed to consider potential foreign material impacts when performing routine tasks or when confronted with changes in job conditions. The licensee's apparent cause report also documented that the operators were sensitive to the foreign material concerns of having the oil fill connection open to the environment and this was discussed as part of the pre-job brief. However, the introduction of the oil nozzle into the fill connection was not recognized or discussed at the pre-job brief.

The inspectors independently reviewed the following documents:

- WO 382152; SP 1295 D1 Diesel Generator 6 Month Fast Start;
- SP 1295; D1 Diesel Generator 6 Month Fast Start;
- FP-G-DOC-03; Procedure Use and Adherence; and
- 5AWI 8.7.0; Foreign Material Exclusion Program Description.

Based upon this document review, the inspectors were not in full agreement with the licensee's apparent cause. The inspectors determined that Section 6.1 of 5AWI 8.7.0 required that a determination be made regarding which systems or components must be opened or accessed in connection with a scheduled task as part of the work planning process. The inspectors reviewed WO 382152 and found that it failed to contain a determination or any other information regarding the need to invoke foreign material exclusion requirements even though Step 3.7 of SP 1295 could result in opening the D1 diesel generator lube oil system to add oil. The inspectors also noted that Step 3.7 of SP 1295 directed operations personnel to add oil using a 55 gallon drum of “filtered” oil as necessary. Prior to mid-2009, operations personnel added oil by transporting a 55 gallon drum of oil into the diesel generator room. Due to the erection of partial walls to protect the diesel generators from the impact of an internal flood, 55 gallon drums were no longer able to be easily transported into the diesel generator rooms. As a result, the method of performing Step 3.7 of SP 1295 had changed. However, this change had not been evaluated for potential impact by operations personnel. The inspectors also questioned whether a procedure change needed to be initiated to address the change in methodology. Had a procedure change been initiated, the need for additional foreign material exclusion controls may have been identified.

Analysis: The inspectors determined that failure to provide instructions and procedures appropriate to the circumstance was a performance deficiency that required an evaluation using the SDP. The inspectors determined that the finding was more than minor because it was associated with the procedure quality and human performance attributes of the Mitigating Systems Cornerstone and impacted the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that this finding was of very low safety significance in accordance with IMC 0612 “Significance Determination Process” Attachment 4 Table 4a, because it did not represent a loss of a system safety function and the diesel generator was inoperable for less than the TS allowed outage time. This finding was determined to be cross-cutting in the Human Performance, Work Control area because the licensee failed to appropriately plan work activities by incorporating job site conditions, which may impact plant structures, systems or components (H.3(a)).

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality shall be prescribed by, and be accomplished in accordance with, documented instructions or procedures appropriate to the circumstance. Contrary to the above, on March 15, 2010, the licensee failed to accomplish WO 382152 and SP 1295 (activities affecting quality) with instructions and procedures appropriate to the circumstance. Specifically, both the SP and the WO failed to contain a determination regarding the need for foreign material exclusion controls even though steps were taken to open the D1 diesel generator lube oil sump and the methodology for adding the oil had changed. This resulted in the introduction of foreign material into the D1 lube oil sump rendering the diesel generator inoperable. Since this finding was of very low safety significance, and because it was entered into the corrective action program as CAP 1222649, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy. (NCV 05000282/2010003-04; Inadequate Foreign Material Exclusion Controls Associated with Work on Emergency Diesel Generators). Corrective actions included retrieving the hose and nozzle, replacing the plastic oil cans with new solid metal cans, and revising the pre-job brief instructions and “Are You Ready” checklist to include a question whether foreign material will be generated through the use of portable equipment or tools.

4OA5 Other Activities

.1 (Discussed) NRC Temporary Instruction 2515/177: Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems (NRC Generic Letter 2008-01)

As documented in Section 1R18 of this report, the inspectors reviewed permanent modifications made to the above systems to address the reduction or elimination of air in system piping. This inspection effort counted towards the completion of TI 2515/177, which will be closed in a later inspection report.

.2 (Closed) Unresolved Item 05000282/2009007-03; 05000306/2009007-03: Sequential Starting of Fire Pumps

The inspectors reviewed a previously identified issue concerning the starting sequence for fire pumps. The Prairie Island Nuclear Generating Plant fire pumps were arranged to start sequentially upon decreasing pressure in the fire protection system. Specifically, the electric-driven fire pump would start at 95 pounds per square inch gauge (psig) and the diesel-driven fire pump would start at 90 psig. The pumps were installed in parallel. At the time of the April 2009 inspection, the licensee provided information to the inspectors that no time delays had been incorporated into the pump circuits. A lack of time delays is contrary to National Fire Protection Association (NFPA) 20 – 1969, "Standard for the Installation of Stationary Pumps for Fire Protection" requirements to incorporate sequential timing devices in the controllers for multiple pump units.

On April 9, 2010, the licensee informed the inspectors that the controller for the diesel-driven fire pump incorporated a 10-second time delay and that previously provided information was incorrect. The inspectors reviewed the schematic diagrams for the diesel fire pump circuitry and confirmed that there was a 10-second time delay shown as part of the circuitry. In addition, the licensee confirmed through review of computer logs of previously conducted surveillance tests, that there was a 10-second time delay from the time the pressure reached the set point and when the diesel fire pump started. The inspectors considered the installed time delay to be sufficient to meet the intent of the NFPA 20 standard requirement to prevent multiple pumps from starting simultaneously.

Based on this review, this URI is closed.

.3 Unit 2 Primary-to-Secondary Leakage

a. Inspection Scope

The inspectors reviewed the operator response and procedure guidance regarding the identification of a primary to secondary leak on Unit 2. Specifically, the inspectors reviewed the licensee's abnormal operating procedure and compared the procedure guidance to industry information developed by the EPRI and endorsed by the NRC. The inspectors also monitored the results of the licensee's sampling program and ensured that the frequency met procedural requirements. At the conclusion of the inspection period, the inspectors were continuing to monitor the licensee's efforts to identify the affected steam generator and the amount of leakage.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 8, 2010, the inspectors presented the inspection results to Mr. Mark Schimmel and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The results of the radioactive solid waste processing and radioactive material handling, storage, and transportation inspection with Mr. Brad Sawatzke, Director Site Operations, on April 30, 2010;
- The results of the inservice inspection with Mr. Brad Sawatzke, Director Site Operations, on May 13, 2010; and
- The closure of URI 05000282/2009007-03; 05000306/2009007-03, "Sequential Starting of Fire Pumps," with Mr. Kevin Ryan, Plant Manager, and other members of the licensee's staff via telephone on June 10, 2010.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements, which meet the criteria of Section VI.A.1 of the NRC Enforcement Policy for being dispositioned as NCVs.

- Section 50.65 (a)(iv) of Title 10 of the Code of Federal Regulations requires that licensee's assess and manage the increase in risk that may result from proposed maintenance activities prior to performing maintenance. Contrary to the above, on May 12, 2010, the licensee failed to properly assess and manage the risk associated with establishing the RCS as intact, releasing the containment airlock operator from duties, and the removal of equipment hatch from the Unit 2 containment. This resulted in Unit 2 entering an unplanned orange shutdown safety assessment path for the containment closure function. This issue was documented in CAP 1232396. Corrective actions included re-establishing the RCS as intact, closing the equipment hatch, re-instating the airlock operator, developing a procedure to clearly state the requirements to be met to declare the RCS intact, and a review of other outage activities to ensure that they were governed by specific procedures appropriate to the circumstance.

  The inspectors determined that the failure to properly assess plant risk in accordance with 10 CFR Part 50.65(a)(iv) was a performance deficiency that required an SDP evaluation. The inspectors consulted Inspection Manual Chapter (IMC) 0609, Appendix K, "Maintenance Rule Risk Assessment Significance Determination Process," and found that this appendix could not be used due to the qualitative nature of shutdown safety assessments. Appendix K suggested that qualitative risk assessment issues be evaluated through a management review performed in accordance with IMC 0609, Appendix M. The inspectors were concerned with this approach since Unit 2 was shut down at the time this finding occurred. The inspectors consulted a Region III Senior Reactor Analyst (SRA) for additional assistance. Using IMC 0609, Appendix G, "Significance Determination Process for Shutdown Conditions," the SRA determined that Unit 2 was in plant outage state #2. The SRA also found that the shutdown SDP stated that IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," should be used for shutdown findings related to containment issues. Using Section 4.0 of Appendix H, the SRA determined that this finding was a type B finding since it was related to a condition that had potentially important implications for the integrity of containment without affecting the likelihood of core damage. The SRA then used Section 6.2, "Approach for Assessing Type B Findings at Shutdown," and determined that this finding was of low safety significance (Green) because it occurred during the late time window of the outage.

- Criterion V to 10 CFR Part 50, Appendix B, requires that activities affecting quality be prescribed by instructions, procedures and drawings appropriate to the circumstance. Contrary to the above, on May 19, 2010, the procedure for testing the 21 and 22 residual heat removal pump suction line check valves, SP 2369, was not appropriate to the circumstance. Specifically, the procedure was not written to appropriately account for system and testing configuration changes made to address previously identified voiding issues. As a result, the test failed to meet the pre-established acceptance criteria. This issue was documented in CAP 1233577. Corrective actions for this issue included revising the testing methodology to account for the system and test configuration changes and successfully re-performing the test. The licensee also planned to review other procedure changes made to address the voiding issue.

  The inspectors determined that the failure to have a procedure appropriate to the circumstance was a performance deficiency that required an SDP evaluation. The inspectors determined that this finding was of very low safety significance (Green) because it was not a design or qualification deficiency, it did not represent a loss of safety function, and it did not screen as potentially risk significant due to a seismic, flooding or severe weather initiating event.

- Technical Specification 5.4.1 requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, Section 9.b requires that preventive maintenance schedules be developed to specify the inspection or replacement of parts that have a specific lifetime. Contrary to the above, on January 26, 2010, the licensee determined that a preventive maintenance schedule for the motor capacitors for the diesel-driven cooling water pump oil storage tank pumps were not developed such that the motor capacitors (which have a 10 year lifetime) were replaced on a periodic basis.

As a result, the 122 diesel cooling water pump oil storage tank pump failed surveillance testing due to a failed motor capacitor. This issue was documented in CAP 1215266. Corrective actions for this issue included replacing the 122 oil storage tank pump and developing a periodic capacitor replacement schedule.

The inspectors determined that the failure to develop a preventive maintenance schedule for replacement of the motor capacitors was a performance deficiency that required an SDP evaluation. The inspectors determined that this finding was of very low safety significance (Green) because it was not a design or qualification deficiency, it did not represent a loss of safety function, and it did not screen as potentially risk significant due to a seismic, flooding or severe weather initiating event.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Schimmel, Site Vice President
B. Sawatzke, Director Site Operations
K. Ryan, Plant Manager
J. Anderson, Regulatory Affairs Manager
S. Derleth; Radiation Protection Shipping Specialist
C. England, Radiation Protection/Chemistry Manager
D. Kettering, Site Engineering Director
J. Lash, Operations Manager
R. Madjerich, Production Planning Manager
M. Milly, Maintenance Manager
J. Muth, Nuclear Oversight Manager
S. Northard, Performance Improvement Manager
K. Peterson, Business Support Manager
A. Pullam, Training Manager

Nuclear Regulatory Commission

J. Giessner, Reactor Projects Branch 4 Chief
R. Orlikowski, Reactor Projects Branch 4 Chief (Acting)
T. Wengert, Office of Nuclear Reactor Regulation Project Manager

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

050000306/2010003-01	FIN	Failure to Address Design Vulnerability Results in Reactor Trip
050000306/2010003-02	NCV	Lack of Operator Procedure Use During System Alignment
050000306/2010003-03	URI	Review Licensee's Evaluation to Determine Whether Performance Deficiency Existed
050000282/2010003-04	NCV	Inadequate Foreign Material Exclusion Controls Associated with Work on Emergency Diesel Generators

Closed

050000306/2010003-01	FIN	Failure to Address Design Vulnerability Results in Reactor Trip
050000306/2010003-02	NCV	Lack of Operator Procedure Use During System Alignment
050000282/2010003-04	NCV	Inadequate Foreign Material Exclusion Controls Associated with Work on Emergency Diesel Generators
05000282/2009-006-00	LER	Unanalyzed Condition Due to Potential Safety System Susceptibility to Turbine Building Flooding Due to a Postulated High Energy Line Break

05000282/2009-006-01	LER	Unanalyzed Condition Due to Potential Safety System Susceptibility to Turbine Building Flooding Due to a Postulated High Energy Line Break
05000306/2010-001-00	LER	Unit 2 Turbine Trip During Reactor Shutdown Resulting in a Reactor Scram
05000282/2010-002-00	LER	Postulated Flooding of Unit 1 Fuel Oil Transfer Pump Motor Starters Could Have Resulted in Reduced Fuel Oil Inventory
05000282/2009007-03; 05000306/2009007-03	URI	Sequential Starting of Fire Pumps

Discussed

2515/177	TI	Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems

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

- Procedure D104.1; Zebra Mussel Control Treatment: Circulating Water System; Revision 10
- CAP 1181810; CT 12 Gas Pressure Low Out of Spec; May 12, 2009
- CAP 1187578; Negative Dissolve Gas Trends for 2GT, 2M, and 1GT Transformer; June 20, 2009
- CAP 1188320; CT1 High Voltage Bushings Degraded and Needs to be Replaced; July 7, 2009
- CAP 1189481; Missing Section of Filter Media on 2GT Transformer; July 15, 2009
- CAP 1189513; PM 4910-16 for Six Month Large Transformers Advisory Items; July 16, 2009
- CAP 1191004; Evaluate NRC IN 2009-10: Transformer Failures – Recent Operating Experience; July 27, 2009
- CAP 1192491; Unable to Perform Quarterly Planned Preventive Station Transformers; August 6, 2009
- CAP 1195856; CT 12/XFMR the Breaker for the Fans and Heaters Tripped; August 31, 2009
- CAP 1199559; PI Requested 101.8 Percent Post-Trip Volts due to Inadequate C20.3; September 25, 2009
- CAP 1202922; 2RS Transformer low Gas Pressure; October 17, 2009
- CAP 1207827; Damaged Cooling Fan on 10 Bank; November 22, 2009
- CAP 1510022; Maintenance Procedures for 1R Transformers Not Implemented by PMRQs; December 9, 2009
- CAP 1212590; CT1 Transformer Dissolved Gas Analysis Shows High Oxygen Content; January 5, 2010
- CAP 1213070; CT-12 Transformer Gas Pressure at Vacuum During Cold Weather; January 9, 2010
- CAP 1222094; CT1 Transformer Dissolved Gas Analysis Shows High Oxygen Content; March 10, 2010
- CAP 1236672; 10 Bank Transformer Total Dissolved Combustible Gas Level into Condition 2; June 9, 2010
- CAP 1236667; CT 12 Transformer Dissolved Gas Analysis Shows Step Change in Oxygen Content; June 9, 2010
- C20.3 AOP12; Grid Voltage or Frequency Disturbances; Revision 5
- C20.3; Electrical Power System Security Analysis; Revision 15
- Transformer Health and Status Report; June 10, 2010

1R04 Equipment Alignment

- Procedure C1.1.20.7-13; D6 Diesel Generator Valve Status; Revision 14
- Procedure C1.1.20-7-14; D6 Diesel Generator Auxiliaries and Local Panels and Switches; Revision 12
- Procedure C1.1.20.7-15; D6 Diesel Generator Main Control Room Switch and indicating Light Status; Revision 6
- Procedure C1.1.20.7-16; D6 Diesel Generator Circuit Breakers and Panel Switches; Revision 8

- Procedure C16-1; Spent Fuel Pool Cooling System Prestart Checklist; Revision 14
- Operations Manual B16; Spent Fuel Pool Cooling System; Revision 7
- Operations Manual C-16; Spent Fuel Pool Cooling System; Revision 52
- CAP 1231015; MC-32122 Closed with no Operator Action; May 4, 2010
- WO 385223; Three Year Pressure Test SP 1168.5; April 16, 2010
- D5 Diesel Generator Maintenance Rule a(1) Plan; Revision 5
- Health and Status Report; D5 Diesel Generator; March 26, 2010
- Procedure C1.1.20.7-10; D5 Diesel Generator Auxiliaries and Local Panel Switches; Revision 11
- Procedure C1.1.20.7-11; D5 Diesel Generator Main Control Room Switch and Indicating Light Status; Revision 5
- Procedure C1.1.20.7-12; D5 Diesel Generator Circuit Breakers and Panel Switches; Revision 9
- Procedure C28-7; Auxiliary Feedwater System Unit 2; Revision 50
- C1.1.20.7-9; D5 Diesel Generator Valve Status; Revision 11
- CAP 1206719; Connecting Rod Bearing Part 21 Issues; November 12, 2009
- CAP 1210203; Rockwell-Edwards Valve, Part 21 Issues; December 10, 2009
- CAP 1097138; Oil Sump Level Switch Mount Discrepancy; June 15, 2007
- CAP 1090396; DG Surveillance Test Procedures; May 1, 2007
- CAP 1049042; EDG Frequency Variation Impact; September 8, 2006
- CAP 831627; D5 Slow Start Surveillance Terminated due to High Crankcase; April 11, 2005
- CAP 1086210; Unable to reduce D5 EDG Load<800 KW During Shutdown; April 5, 2007
- CAP 1221675; U2 D5 Engine 2 Crankcase Pressure; March 8, 2010
- CAP 1217274; D-5 Lock-Out; February 8, 2010
- CAP 1201138; U2 SP 2093 Couldn’t Reduce D5 Load <700KW; October 5, 2009

1R05 Fire Protection

- Fire Hazards Analysis
- Safe Shutdown Analysis
- Procedure F5, Appendix A; Fire Zone Plans and Maps; Various Revisions

1R08 Inservice Inspection Activities

- FP-PE-NDE-402; Ultrasonic Examination of Austenitic Pipe Welds - Supplement 2; Revision 2
- Procedure 2H25.1; Unit 2 Degradation Assessment; Revision 6
- Procedure 2H25.2; Unit 2 Steam Generator Condition Monitoring; Revision 6
- Procedure 2H25.3; Unit 2 Steam Generator Tube Repair Criteria; Revision 3
- Procedure D27.21; Steam Generator Tube Repair; Revision 30
- PI-400-001; Multi-frequency Eddy Current Examination of Non-Ferromagnetic Steam Generator Tubing; Revision 11
- PINGP 1507; Boric Acid Corrosion Control Leak Inspection; Revision 2
- SP 2403; Reactor Vessel Closure Head Bare Metal Visual Examination; Revision 3
- SP 2407; Leakage Examination of Pressure Retaining Components on the Reactor Vessel Head; Revision 3
- H2 Boric Acid Corrosion Control Program; Revision 15
- MSIP 1078; Leak Walkdowns; Revision 0
- SWI-NDE-VT-6.0; Visual Examination for Leakage on Reactor Vessel Penetrations (VT-2); Revision 0
- WO 304396; Install EC 11442, Pipe and Valve Downstream of 2RC-8-39

- WPS FP-PE-B31-P8P8-GTSM-037 Groove Welds and Fillet Welds, P8-P8, GTAW/SMAW, Without PWHT; Revision 2
- DAEC-W-66; PQR for WPS FP-PE-B31-P8P8-GTSM-037; October 12, 1989
- SP 2392; Unit 2 Insulated Bolted Connection Inspection; Revision 4
- SWI NDE-PT-1; Solvent Removable Visible Dye Penetrant Examination; Revision 1
- H10.5; 4th Interval Inservice Inspection Plan – Units 1 and 2, December 21, 2004, through December 20, 2014; Revision 5
- CAP 1228864; Loose Nut on Clamp; April 22, 2010
- CAP 1230558; Loose Bolt on Top Side of Tie Back; April 26, 2010
- CAP 1153719; Evaluate the 2R25 SG Degradation; October 4, 2008

1R12 Maintenance Effectiveness

- Health and Status Report; Steam Exclusion; April 7, 2010
- Health and Status Report; External Circulating Water; June 2, 2010
- Maintenance Rule System Specific Basis Document; Revision 14
- CAP 1209247; Found 48335 Out-of-Tolerance During SP 1599; December 3, 2009
- CAP 1139238; Loss of FME Control in ZD System; May 30, 2008
- CAP 1143615; Steam Exclusion Temp Out Of Tolerance; July 9, 2008
- CAP 1147073; Inadequate Documentation and Parts for Damper on PO XH-505; August 8, 2008
- CAP 1168075; CD-34188 Won't Go Full Close Per SP 1112; February 4, 2009
- CAP 1187281; TI-7005112, Bus 111 and 121 STM EXCL B Train Deviating; June 28, 2009
- CAP 1199304; TE 15688 Failed SP 1112 Out of Spec High; September 23, 2010
- CAP 1209241; Found 48326 Out-of-Tolerance During SP 1599; December 3, 2009
- CAP 1221928; SV-91308 121 Bypass Gate Emergency Open Solenoid Valve Sticking; March 10, 2010
- CAP 1223961; 121 Intake Screenhouse Bypass Gate Didn't Open on Loss of Power; March 24, 2010
- CAP 1227411; SV-91308 Failed on First Attempt on Loss of Power Twice in 2 Week Period; April 15, 2010
- CAP 1227625; Need to Revisit Resolution/Closeout of Root Cause Evaluation 171; April 16, 2010
- CAP 1160660; SV-91308 and SV-91311 121 and 122 Bypass Gate Emergency Open Solenoid Valves; November 26, 2008

1R13 Maintenance Risk Assessment and Emergent Work

- Stoplight Memo; Unit 2 Shutdown Safety Assessment Unplanned Orange Condition; May 12, 2010
- Procedure 2C4.2; Reactor Coolant System Inventory Control – Post Refueling; Revision 25
- Narrative Logs; May 11-12, 2010
- Procedure 2C1.6; Shutdown Operations – Unit 2; Revision 23
- FP-G-DOC-03; Procedure Use and Adherence; Revision 8
- CAP 1232396; Reactor Coolant System was Declared Intact When 2RC-21-1 was Open; May 12, 2010
- Unit 2 Shutdown Safety Assessments; May 11–12, 2010
- CAP 1226555; Delays in Returning Blue Channel to Service; April 9, 2010
- Procedure FP-WM-IRM-01; Integrated Risk Management; Revision 3
- WO 382583; Bad Output During SP 2003 – Replace 2TM-403V; April 8, 2010
- QF 2010; Work Order Risk Screening Worksheet; Revision 6

1R15 Operability Evaluations

- CAP 1226049; Low Wall Thickness Found on 24-CL-13; April 6, 2010
- Evaluation 1226049; Low Wall Thickness Found on 24-CL-13; April 7, 2010
- CAP 1230668; Unit 1 Bus Source Breakers; May 3, 2010
- Evaluation 1230668; Unit 1 Bus Source Breakers; Revision; May 10, 2010

1R18 Modifications

- 50.59 Screening #3424; EC 13483 – GL 08-01 Vent Valve Modification for ECCS Piping in Unit 2; Revision 1
- EC 13483; GL 08-01 Vent Valve Modification for ECCS Piping in Unit 2; Revision 0
- BOP-VE-10-021; Ultrasonic Examination Report; May 09, 2010
- BOP-VE-10-020; Ultrasonic Examination Report; May 09, 2010
- BOP-VE-10-034; Ultrasonic Examination Report; May 15, 2010
- BOP-VE-10-031; Ultrasonic Examination Report; May 15, 2010
- BOP-VE-10-033; Ultrasonic Examination Report; May 15, 2010
- BOP-VE-10-034; Ultrasonic Examination Report; May 15, 2010
- BOP-VE-10-039; Ultrasonic Examination Report; May 16, 2010
- BOP-VE-10-038; Ultrasonic Examination Report; May 16, 2010
- BOP-VE-10-037; Ultrasonic Examination Report; May 16, 2010
- BOP-VE-10-041; Ultrasonic Examination Report; May 17, 2010
- BOP-VE-10-042; Ultrasonic Examination Report; May 17, 2010
- BOP-VE-10-044; Ultrasonic Examination Report; May 18, 2010
- BOP-VE-10-047; Ultrasonic Examination Report; May 18, 2010
- Drawing SK-EC-13483-01; General Construction Notes; Revision 0A-1
- Drawing SK-EC-13483-02; Vent Valve Installation Void Location 2CS-02; Revision 0A-1
- Drawing SK-EC-13483-03; Vent Valve Installation Void Location 2CS-03; Revision 0A-1
- Drawing SK-EC-13483-04; Vent Valve Installation Void Location 2CS-06; Revision 0A-1
- Drawing SK-EC-13483-05; Vent Valve Installation Void Location 2CS-07; Revision 0A-1
- Drawing SK-EC-13483-06; Vent Valve Installation Void Location 2CS-10; Revision 0A-1
- Drawing SK-EC-13483-07; Vent Valve Installation Void Location 2CS-11; Revision 0A-1
- Drawing SK-EC-13483-08; Vent Valve Installation Void Location 2CS-12; Revision 0A-1
- Drawing SK-EC-13483-09; Vent Valve Installation Void Location 2CS-13; Revision 0A-1
- Drawing SK-EC-13483-10; Vent Valve Installation Void Location 2CS-14-1; Revision 0A-1
- Drawing SK-EC-13483-11; Vent Valve Installation Void Location 2CS-15; Revision 0A-1
- Drawing SK-EC-13483-12; Vent Valve Installation Void Location 22PIT-02-1; Revision 0A-1
- Drawing SK-EC-13483-13; Vent Valve Installation Void Location 22PIT-02-2; Revision 0A-1
- Drawing SK-EC-13483-14; Vent Valve Installation Void Location 22PIT-05; Revision 0A-1
- Drawing SK-EC-13483-15; Vent Valve Installation Void Location 2RH-06; Revision 0A-1
- Drawing SK-EC-13483-15A; Vent Valve Installation Void Location 2RH-06; Revision 0A-1
- Drawing SK-EC-13483-16; Vent Valve Installation Void Location 2RH-09; Revision 0A-1
- Drawing SK-EC-13483-17; Vent Valve Installation Void Location 2RH-10; Revision 0A-1
- Drawing SK-EC-13483-20; Vent Valve Installation Void Location 2SI-12; Revision 0A-1
- Drawing SK-EC-13483-21; Vent Valve Installation Void Location 2SI-12; Revision 0A-1
- Drawing SK-EC-13483-22; Vent Valve Installation Void Location 2SI-13; Revision 0A-1
- Drawing SK-EC-13483-23; Vent Valve Installation Void Location 2SI-14A; Revision 0A-1
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- Drawing SK-EC-13483-25; Vent Valve Installation Void Location 2SI-2; Revision 0A-1
- Drawing SK-EC-13483-26; Vent Valve Installation Void Location 2SI-33B; Revision 0A-1
- Drawing SK-EC-13483-27; Vent Valve Installation Void Location 2SI-33A; Revision 0A-1

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- Drawing SK-EC-13483-30; Vent Valve Installation Void Location 2SI-46; Revision 0A-1
- Drawing SK-EC-13483-31; Vent Valve Installation Void Location 2SI-16; Revision 0A-1
- Drawing SK-EC-13483-32; Vent Valve Installation Void Location 2RH-06; Revision 0A-1
- ENG-ME-449; Assessment of Containment Heat Sinks; Revision 1
- FP-PE-NDE-426; Ultrasonic Examination for Determination of Fluid Levels; Revision 1
- EC 12617; Temporary Air Compressor for Service Air System; Design Input Checklist - Part A Engineering Programs and Departmental Reviews; No Date
- EC 12617; Temporary Air Compressor for Service Air System; Design Input Checklist - Part B Design Considerations, Requirements, and Standards; No Date
- EC 12617; Temporary Air Compressor for Service Air System; Design Input Consultation Form; April 30, 2008
- EC 12617; Temporary Air Compressor for Service Air System; Modification Classification; April 30, 2008
- 50.59 Screening; EC 12617; Temporary Air Compressor for Service Air System; Revision 0
- C33; Station Air System; Revision 33 (with temporary change mark-ups)
- CAP 1226570; Portable Air Compressor Near Fuel Oil Storage Tanks; April 9, 2010
- EC 12617; Connect a Temporary Air Compressor to the Service Air System Using Existing 2-1/2 Inch System Header; May 14, 2008

1R19 Post-Maintenance Testing

- SP 2102; 22 Turbine-Driven AFW Pump Monthly Test; Revision 88
- WO 399163; Replace 22 Turbine-Driven AFW Pump Turbine Thermocouple; April 12, 2010
- WO 393350-14; D6 Diesel Break In Run; May 14, 2010
- Work Plan 393350-14; D6 Diesel Break In Run; May 14, 2010
- CAP 1211427; D5 Bearing Replacement Timing/ Methodology; December 21, 2009
- Evaluation 1206719; Part 21 Reporting of an Issue with Wartsila/SACM UD-45 Connecting Rod Bearings; November 13, 2009
- SP 2331; 21 Motor-Driven AFW Pump Auto Start and Functional Testing Each Refueling Shutdown; Revision 19
- WO 326939; SP 2331 21 Motor-Driven AFW Pump Auto Start and Function Testing Each Refueling Shutdown; May 1, 2010

1R20 Refueling and Outage

- 2C1.4; Unit 2 Power Operation; Revision 45
- 2C1.3; Unit 2 Shutdown; Revision 67
- D30; Post Refueling Startup Testing; Revision 48
- D58; Heavy Loads Program; Revision 33
- D58.2.9; Unit 2 Reactor Vessel Head Removal; Revision 17B
- D58.2.10; Unit 2 Reactor Vessel Head Replacement; Revision 15
- MSIP 7004; Unit 1 and Unit 2 Reactor Vessel Head Removal Pre-Job Briefing; Revision 8
- CAP 1228394; Non-Conservative Input Used in Heavy Load Drop Dose Analysis; April 21, 2010
- 50.59 Screening; Eliminate Opening Allowances in Containment while Moving Heavy Loads Over Irradiated Fuel in C19.9; April 22, 2010
- C19.9; Containment Boundary Control During Mode 5, Cold Shutdown and Mode 6, Refueling; Revision 13

- C19.9-2; Inventory and Refueling Integrity Containment Boundary Checklist – Unit 2; Revision 18
- WO 387079-01; SP 2421 Unit 2 Reactor Vessel Bottom Head Bare Metal Visual Examination; April 24, 2010
- WO 327134-01; SP 2405 Unit 2 Mid-Cycle and Refueling Outage Boric Acid Corrosion Examination Inside Containment; April 14, 2010
- SP 2405; Unit 2 Mid-Cycle and Refueling Outage Boric Acid Corrosion Examinations Inside Containment; Revision 4
- SP 2421; Reactor Vessel Bottom Head Bare Metal Visual Examination; Revision 2
- Calculation 2005-05621; Analysis of Postulated Reactor Head Load Drop; Revision 1
- WO 00326749-01; PM 3160-1 21 Containment Polar Crane Mechanical Inspection; April 15, 2010
- PM 3160-1; Containment Polar Crane Mechanical Inspection; Revision 13
- WO 00393473-10; Unit 2 Conduct ISI Exams in Containment in 2R26; April 6, 2010
- NDE Report 2010P005; CRD32 Latch Housing and Head Adapter; April 28, 2010
- NDE Report 2010P006; CRD22 Latch Housing and Head Adapter; April 28, 2010
- NDE Report 2010P007; CRD31 Latch Housing and Head Adapter; April 28, 2010
- NDE Report 2010P008; CRD26 Latch Housing and Head Adapter; April 28, 2010
- SWI NDE-PT-1; Solvent Removable, Visable Dye Penetrant Examination; Revision 1
- SP 2750; Post Outage Containment Close-Out Inspection; Revision 34
- SP 2177; Core Inventory Verification; Revision 15
- WO 327160-01; SP 2177 Refuel Core Inventory Verification
- Unit 2 Cycle 26 Core Inventory Verification Video; May 6, 2010
- 50.59 Evaluation #1076 (Document #03FH02-226); Unit 2 Cycle 26 Core Reload; Revision 0
- Westinghouse Reload Safety Evaluation – Prairie Island Unit 2 Cycle 26
- Prairie Island Nuclear Generating Plant Core Operating Limits Report – Unit 2 Cycle 26; Revision 0
- Reactor Startup Following 2R26 Plant Operations Review Committee Meeting 3109 Meeting Minutes; May 21, 2010
- Operating Experience Smart Sample FY2007-03; Crane and Heavy Lift Inspection; Revision 0
- Shutdown Safety Assessments; dated April 17, 2010, through May 21, 2010
- SP 2277; General Visual Examination of the Containment Vessel for ASME Subsection IWE; Revision 2
- NRC Commitments 1028 and 1029; Reply to Notice of Violation 92-06 – Inadequate Procedure for Draindown to Midloop; June 1, 1992
- 50.59 Evaluation 1077; Removal of NRC Commitments 1028 and 1029 for Non-Intrusive Reactor Coolant System Level Indicators During Reduced Inventory Operations; April 19, 2010
- Procedure 2C12.2; Purification and Chemical Addition – Unit 2; Revision 24
- Plant Operations Review Package; May 21, 2010
- SP 2750; Post Outage Containment Close-Out Inspection; Revision 34

1R22 Surveillance Test

- WO 376539-01; SP 2431 Main Steam Safety Valve Test (Power Operation); April 14, 2010
- SP 2431; Main Steam Safety Valve Test (Power Operation); Revision 1
- WO 367330-01; SP 2070 Reactor Coolant System Integrity Test; April 17, 2010
- SP 2070; Reactor Coolant System Integrity Test; Revision 38
- WO 397239-01; SP 1094 Bus 15 Load Sequencer; May 04, 2010
- SP 1094; Bus 15 Load Sequencer; Revision 27

- WO 327093-01; SP 2083 Unit 2 Integrated SI Test with a Simulated Loss of Offsite Power; April 17, 2010
- SP 2083; Unit 2 Integrated SI Test with a Simulated Loss of Offsite Power; Revision 31
- WO 367335-01; SP 2277 General Visual Examination of the Containment Liner for ASME Subsection IWE; April 17, 2010
- SP 2277; General Visual Examination of the Containment Liner for ASME Subsection IWE; Revision 1A
- WO 397929-01; SP 1090B 12 Containment Spray Pump Quarterly Test; May 4, 2010
- SP 1090B; 12 Containment Spray Pump Quarterly Test; Revision 17

2RS8 Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation

- CAP 1157726; Radioactive Material Shipment Exceeded DOT Limits; Revision 2
- C49.10; Clamshell Operations; Revision 13
- D11.7; Radioactive Material Shipment LSA/SCO/LDT Quantity to a Licensed Facility; Revision 21
- D11.11; Radioactive Material Shipment LSA/SCO/LDT Quantity to a Licensed Processing Facility; Revision 17
- D20.13; Sluicing Resin from 12 Mixed Bed IX to 121 Spent Resin Tank; Revision 19
- D20.16; Sluicing Resin from 11 Evap Condensate IX to a Resin Shipping Liner; Revision 16
- D59; Process Control Program for Solidification/Dewatering of Radioactive Waste from Liquid Systems; Revision 9
- FP-WM-IRM-01; Integrated Risk Management; Revision 3
- Radiological Survey Records; Various Dates
- RPIP 1303; Packaging of Radioactive Material for Shipment; Revision 5
- RPIP 1307; Radioactive Waste Classification; Revision 8
- RPIP 1310; Radioactive Waste Streams Scaling Factors; Revision 8
- RPIP 1319; Loading LSA Boxes/Sealand Containers; Revision 17
- RPIP 1721; Resin Sluice; Revision 19
- QF-2007; (FP-WM-IRM-01); Planning and Approval of High Risk or Scheduled Risk Work; Revision 3
- QF-2010; (FP-WM-IRM-01); Work Order Risk Screening Worksheet; Revision 6
- Shipment Number 09-024; Hn-215 Cask – Dewatered Resin; November 2009
- Shipment Number 09-025; Hn-215 Cask – Dewatered Resin; November 2009
- Shipment Number 09-030; DAW Sealands; December 2009
- Shipment Number 10-005; DAW Sealands; January 2010
- Shipment Number 10-008; DAW Sealands; February 2010

4OA1 Performance Indicator Verification

- SWI O-53; Operations Performance Indicators Reporting; Revision 5
- Monthly Data for RCS Identified leakage
- CAP 1186923; NRC Identifies Discrepancies with Reported Data; June 25, 2009
- SP 1001AA; Daily Reactor Coolant System Leakage Test; Revision 51
- SP 2001AA; Daily Reactor Coolant System Leakage Test; Revision 48

4OA2 Identification and Resolution of Problems

- CAP 1208884; Unit 2 Fuel Oil Out of Specification – Fuel Oil Receiving Tank; December 2, 2009

- CAP 1223538; Document the Basis for 21 D5/D6 Fuel Oil Receiving Tank Satisfying H30; March 20, 2010
- CAP 1226499; Lack of Parts to Perform 2R26 Preventive Maintenance Activities; April 28, 2010
- CAP 1210203; 10 CFR Part 21 for Rockwell Edward Valves; December 10, 2009
- CAP 1233549; Unit 2 Charging System Design Pressure Exceeded; May 19, 2010
- CAP 1233070; Lifted Relief Valve Upon Startup of Charging Pump on Outage Unit; May 16, 2010
- Procedure 2C19.1; Containment Unit 2; Revision 20
- Maintenance Rule Monthly Reports; December 2009 – May 2010
- System Health Reports; December 2009 – May 2010

4OA3 Follow-up of Events and Notices of Enforcement Discretion

- Event Notification 45855; Loss of Safety Function Due to Loss of Turbine Building High Energy Line Break Compensatory Measure; April 19, 2010
- Event Notification Retraction 45855; Loss of Safety Function Due to Loss of Turbine Building High Energy Line Break Compensatory Measure; April 22, 2010
- EC 16032; Internal Flooding Evaluation for 4/18/2010 Screen Door Closing Event; April 20, 2010
- Initial Trip Summary; April 17, 2010
- 2C1.3; Unit 2 Shutdown; Revision 66
- 2C1.4; Unit 2 Power Operation; Revision 45
- CAP 527451; Unable to Restore Condenser Vacuum After Turbine Tripped; September 13, 2003
- Equipment Problem Investigation Report; September 20, 2003
- Engineering Work Request 028155; Possible Engineering Change/Minor Modification to Re-Slope and Trap MSR Sealing Steam Lines to MSR Headers; September 19, 2003
- Engineering Work Request 030335; Possible Minor Modification to Install Trap MSR Sealing Steam Lines to MSR Headers; January 14, 2004
- CAP 20014153; During Performance of 2C1.3 – Unit 2 Turbine Manually Tripped Due to High Condenser Differential Pressure with Vacuum Decreasing; May 9, 2001

4OA5 Other Activities

- NE-40014-3; 122 Diesel Fire Pump Schematic; Revision V
- NE-40014-4; 122 Diesel Fire Pump Schematic; Revision K
- NF-40318-1; Interlock Logic Diagram for Fire Protection and Screen Wash System, Units 1 and 2; Revision L
- 2C4 AOP2; Steam Generator Tube Leak; Revision 18
- EPRI Document; Pressurized Water Reactor Primary-to-Secondary Leak Guidelines; Revision 3

4OA7 Licensee-Identified Findings

- Stoplight Memo; Unit 2 Shutdown Safety Assessment Unplanned Orange Condition; May 12, 2010
- Procedure 2C4.2; Reactor Coolant System Inventory Control – Post Refueling; Revision 25
- Narrative Logs; May 11-12, 2010
- Procedure 2C1.6; Shutdown Operations – Unit 2; Revision 23
- FP-G-DOC-03; Procedure Use and Adherence; Revision 8

- CAP 1232396; Reactor Coolant System was Declared Intact When 2RC-21-1 was Open; May 12, 2010
- Unit 2 Shutdown Safety Assessments; May 11-12, 2010
- CAP 1233577; Unit 2 RHR Suction Check Valves Fail SP 2369 Closed Function; May 19, 2010
- CAP 1215266; 122 Diesel Cooling Water Pump Oil Storage Tank Pump Failure; January 26, 2010

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
AFW	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CFR	Code of Federal Regulations
DAW	Dry Active Waste
DRP	Division of Reactor Projects
EC	Engineering Change
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPRI	Electric Power Research Institute
ET	Eddy Current
FIN	Finding
GL	Generic Letter
gph	Gallons Per Hour
HELB	High Energy Line Break
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
ISI	Inservice Inspection
LER	Licensee Event Report
MSR	Moisture Separator Reheater
NCV	Non-Cited Violation
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
OSP	Outage Safety Plan
PARS	Publicly Available Records System
PCP	Process Control Program
PI	Performance Indicator
RCS	Reactor Coolant System
RFO	Refueling Outage
SDP	Significance Determination Process
SG	Steam Generator
SP	Surveillance Procedure
SRA	Senior Reactor Analyst
TI	Temporary Instruction
TS	Technical Specification
TSO	Transmission System Operator
URI	Unresolved Item
USAR	Updated Safety Analysis Report
WO	Work Order

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Sincerely,

/RA by Kenneth Riemer for/

Robert J. Orlikowski, Acting Chief
Branch 4
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 M. Schimmel from R. Orlikowski dated July 26, 2010.

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000282/2010003; 05000306/2010003

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