July 21, 2005

Mr. Thomas Palmisano
Site Vice-President
Prairie Island Nuclear Generating Plant
Nuclear Management Company, LLC
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000282/2005004; 05000306/2005004

Dear Mr. Palmisano:

On June 30, 2005, the U. S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on July 12, 2005, with you and other members of your staff.

This 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, the inspectors identified four NRC-identified findings of very low safety significance (Green), three of which involved violations of NRC requirements. Because these three violations were of very low safety significance and because the issues were entered into the licensee's corrective action program, the NRC is treating these findings as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, 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, D.C. 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, D.C. 20555-0001; and the Resident Inspector Office 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 and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

George Wilson, Chief (Acting)
Branch 3
Division of Reactor Projects

Docket Nos. 50-282; 50-306
License Nos. DPR-42; DPR-60

Enclosure: Inspection Report 05000282/2005004; 05000306/2005004
w/Attachment: Supplemental Information

cc w/encl: C. Anderson, Senior Vice President, Group Operations
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306
License Nos:	DPR-42; DPR-60
Report No:	05000282/2005004; 05000306/2005004
Licensee:	Nuclear Management Company, LLC
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	April 1 through June 30, 2005
Inspectors:	J. Adams, Senior Resident Inspector D. Karjala, Resident Inspector M. Holmberg, Reactor Inspector J. Neurauter, Reactor Inspector M. Mitchell, Radiation Specialist M. Wilk, Reactor Engineer
Approved by:	G. Wilson, Chief (Acting) Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000282/2005004, 05000306/2005004; 04/01/2005 - 06/30/2005; Prairie Island Nuclear Generating Plant, Units 1 and 2; Adverse Weather Protection; Fire Protection; Inservice Inspection Activities. and Other Activities.

This report covers a 3-month period of baseline resident inspection and announced baseline inspection on radiation protection, security, and emergency preparedness. The inspection was conducted by the resident inspectors and inspectors from the Region III office. Four Green findings were identified, three of which involved violations of NRC requirements. 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 3, dated July 2000.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a plate of aluminum material unsecured on the south side of the fuel oil transfer house and an unsecured prestaged temporary storage tank in close proximity to the 2M, 2RX, and 2RY transformers. Plant personnel failed to identify these discrepant conditions during the performance of a plant surveillance procedure with the purpose of identifying and removing potential missile hazards from areas where they could damage important plant electrical equipment during adverse weather conditions.

  The finding was more than minor because it affected the protection against external factors attribute of the initiating events cornerstone designed to limit the likelihood of events that upset plant stability. The finding was determined to be of very low safety significance since the finding did not contribute to the likelihood of a primary or secondary system loss of coolant accident initiator, nor did it contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available, and the finding did not increase the likelihood of a fire, or internal or external flooding. The inspectors determined that no violation of NRC requirements were associated with this finding. (Section 1R01.1)

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50.48(a)(2)(I) associated with the licensee’s storage of transient combustibles in the Unit 2 reactor building without required administrative controls.

  The finding was more than minor because it affected the initiating events cornerstone of protection against external factors (fire), and if left uncorrected could have resulted in a greater probability of a fire. Plant personnel failed to identify these transient combustibles during the fire hazard review for work activities and housekeeping tours.

The finding was determined to be of very low safety significance because it was in the category of fire prevention and administrative controls. (Section 1R05.1)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50.55a(g)(4) associated with the licensee's failure to specify an ultrasonic calibration block with appropriate calibration reflectors, that met the American Society of Mechanical Engineers Code in a procedure that performed examinations of the reactor vessel flange-to-shell welds.

  This finding was greater than minor because it affected the barrier integrity cornerstone objective of reactor coolant system equipment and barrier performance, and if left uncorrected could have resulted in allowing unacceptable flaws to remain in-service and the licensee would have relied on an inadequate examination for credit toward completing the required code weld volumetric coverage. The finding was of very low safety significance because this inadequate procedure was identified prior to taking Code credit for this weld examination, and a separate Code qualified examination was conducted on the affected vessel weld. (Section 1R08)

Cornerstone: Mitigating Systems

- Green. The inspector identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having a very low safety significance involving the licensee's failure to adequately apply design control measures to verify the adequacy of certain design calculations. These calculations provided the basis to ensure the safety injection (SI) system would be capable of injecting water into the reactor vessel to remove decay heat following a postulated reactor vessel closure head (RVCH) drop onto the reactor vessel flange. Specifically, non-conservative assumptions and a non-conservative design methodology were used without justification and the calculations did not include all of the structural components that would be affected by a reactor vessel head drop in the design evaluations that provided the basis for the maximum lift elevation allowed for the reactor vessel head removal and replacement during refueling operations.

  This finding was greater than minor because it affected the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events and if left uncorrected, it could become a more significant safety concern, in that the calculational deficiencies resulted in a non-conservative determination of maximum allowable head lift height. The finding was of very low safety significance because the polar crane capacity had considerable margin with respect to the original, lighter weight RVCH, and the issue was appropriately addressed prior to lifting of the heavier replacement RVCH. (Section 4OA5.2)

B. <u>Licensee-Identified Violations</u>

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power throughout the inspection period.

Unit 2 operated at or near full power until April 16, 2005, when it was shut down to repair the D5 diesel generator engines. The unit remained shut down and began refueling outage 2R23. The reactor was restarted on June 9, 2005, and the generator was placed on line on June 11, 2005. The unit was returned to full power on June 13, 2005, and operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Tornado and High Wind Preparations

a. Inspection Scope

On April 28, 2005, the inspectors performed a detailed in-office review of the licensee's procedures and an in-plant walkdown of four systems to observe the licensee's preparations for adverse weather conditions that could result from nearby tornados or high wind conditions. The inspectors performed a detailed review of the tornado and high winds hazard procedures; the Updated Safety Analysis Report (USAR); design basis documents for the Unit 1 and Unit 2 switchyard; and the Prairie Island Individual Plant Examination of External Events (IPEEE.) The inspectors verified that required surveillance tests were scheduled and performed at the specified frequencies. During system walkdowns, the inspectors examined the material condition of major system components for evidence of system degradation. As part of this inspection, the documents in the Attachment were utilized to evaluate the potential for an inspection finding.

The inspectors evaluated readiness for seasonal susceptibilities for the following systems, completing one inspection procedure sample:

- the Unit 1 diesel generator D1;
- the plant substation system;
- the cooling tower substation system including transformers CT-11 and CT-12; and
- auxiliary and standby transformer system.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) for the failure to control materials in the north protected area. The finding was not considered a violation of regulatory requirements.

Description: On April 28, 2005, the inspectors walked down the risk significant portions of the off-site power systems including the switchyard. The inspectors used the walkdown to assess the licensee's preparations to preclude or minimize potential damage from high velocity winds associated with severe thunderstorms and tornados. During the walkdown, the inspectors identified an unsecured aluminum plate covering a below grade pit on the south side of the fuel oil transfer house. The inspectors concluded that high velocity winds combined with the close proximity of these loose materials increased the potential to damage transformers, breakers, disconnects, or other electrical equipment. This issue was entered into the licensee's corrective action program with corrective action program action request (CAP) 042183. The licensee immediately secured the plate with a length of chain.

The inspectors also noted that a large tank was prestaged in close proximity to the 2M, 2RX, and 2RY transformers in preparation for planned outage work on the Unit 2 main power transformer. The inspector noted that the tank was not secured and was located in the north protected area as it is defined in surveillance procedure (SP) 1039. The licensee performed a missile evaluation and concluded that the tank could be blown off its base and fall on 2M, 2RX, or 2RY resulting in transformer damage. This issue was entered into the licensee's corrective action program with CAP 042156. The licensee immediately secured the tank with chains to concrete barriers.

Analysis: The inspectors determined that the failure of operations personnel to identify loose material in the north protected area was a performance deficiency. The inspectors evaluated the finding and determined it to be more than minor in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on June 20, 2003. The inspectors determined that the finding was more than minor because it affected the protection against external factors attribute of the initiating events cornerstone designed to limit the likelihood of events that upset plant stability. Specifically, the increased number of potential missiles in the vicinity of risk significant power systems raised the probability that severe weather could cause a loss of power to Technical Specifications (TS) required power supplies or a loss of off-site power, and thereby initiate a plant transient.

The inspectors completed the significance determination of this finding using IMC 0609, "Significance Determination Process," dated March 21, 2003, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated December 1, 2004. The Phase 1 Significance Determination worksheet identified that the finding did not contribute to the likelihood of a primary or secondary system loss of coolant accident initiator; the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available; and the finding did not increase the likelihood of a fire or internal or external flooding. Therefore, the finding was determined to be of very low safety significance (Green).

Enforcement: SP 1039, Tornado Hazard Monthly Site Inspection, Revision 9, Section 7 directs operators to inspect specified areas and identify the presence of potential missile hazards, and to secure or remove any identified items. If the missile hazard cannot be readily removed or secured, then a work request card shall be submitted. Contrary to the above, operators failed to identify the aluminum plate on the south side of the fuel oil transfer house and the prestaged tank in the proximity of the 2M, 2RX, and 2RY transformers.

The inspectors determined that the performance of the personnel performing the tornado hazard inspection per SP 1039 was inadequate to identify loose materials that could become missile hazards in the event of a tornado or high wind adverse weather conditions. The inspectors reviewed the basis for the surveillance procedure and found that the licensee committed to perform the surveillance procedure in Licensee Event Report (LER) 92-007. After further investigation, the inspectors determined that the commitment made by the licensee in LER 92-007 was specific to the D1 diesel generator only. The inspectors determined that the equipment in the switchyard, and the 1M, 2M, 1R, 2RX and 2RY transformers were not safety-related equipment. However, no violation of NRC requirements occurred because the affected components were not subject to the requirements of 10 CFR Part 50, Appendix B (FIN 05000282/2005004-01; 05000306/2005004-01).

.2 Hot Weather Preparations

a. Inspection Scope

On May 9 and 10, 2005, the inspectors performed an in-office review of the summer plant operation program; the USAR; applicable TS; and the Prairie Island IPEEE. This inspection effort completed the hot weather preparation inspection sample. The inspectors performed in-plant walkdowns of selected systems and verified that the as-found conditions of those systems were consistent with the description provided in the above documents. The inspectors performed in-plant walkdowns of the following risk significant mitigating system support systems for a total of one inspection sample:

- main power, auxiliary, and substation transformers;
- screenhouse safety-related ventilation system; and
- screenhouse normal ventilation system.

The inspectors reviewed the selected systems and verified that the material conditions and system configurations supported the systems' availability and operability under adverse hot weather conditions, and verified that additional cooling equipment, where specified in the summer plant operation procedure, was available and operable.

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

b. Findings

No findings of significance were identified.

1R02 Evaluation of Changes, Tests, or Experiments (71111.02)

Reactor Vessel Closure Head (RVCH) Replacement (71007)

a. Inspection Scope

From April 25, 2005, through April 29, 2005, and from May 23, 2005, through May 27, 2005, the inspector reviewed the licensee's evaluations of applicability determination and screening questions for the design changes associated with the RVCH replacement to determine, for each change, whether the requirements of 10 CFR 50.59 had been appropriately applied. Specifically, the inspector reviewed Part 1 of Design Change 03RV05, "Replace Unit 1 and 2 Reactor Vessel Heads and Associated Components," which included a review of the function of each changed component, the change description and scope of the 10 CFR 50.59 screenings, and 10 CFR 50.59 evaluation for the:

- reactor vessel head, penetrations, and spare penetration caps;
- full length control rod drive mechanism (CRDM) pressure housing and internals;
- thermocouple penetration adapter upgrades, core exit thermocouple nozzle assemblies;
- reactor coolant gas ventilation system (RCGVS) and reactor vessel level indication system (RVLIS) pipe and supports; and
- load combination change from absolute sum to the square root sum of the squares method.

The inspector also reviewed the 10 CFR 50.59 screenings and 10 CFR 50.59 evaluation associated with Part 2 of Design Change 03RV05, "Reactor Vessel Head Assembly Upgrade Package (HAUP)," which included a review of the function of each changed component, the change description and scope the 10 CFR 50.59 screenings, and 10 CFR 50.59 evaluation for the:

- reactor vessel CRDM seismic platform, seismic spacer plate, adjustment plate assembly, cable supports;
- thermocouple and CRDM coil bridge, rod position indication and CRDM drawbridge, messenger lines;
- CRDM cooling: coils, fans, pipe/pipe supports and instrumentation and control;
- reactor vessel CRDM shroud, support ring, access doors, and radiation shield; and
- reactor vessel missile shield.

The inspector used, in part, Nuclear Energy Institute 96-07, "Guidelines for 10 CFR 50.59 Implementation," to determine acceptability of the completed pre-screenings and screening. The Nuclear Energy Institute document was endorsed by the NRC in Regulatory Guide 1.187, "Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments." The inspectors also consulted Part 9900 of the

NRC Inspection Manual, “10 CFR Guidance for 10 CFR 50.59, Changes, Tests, and Experiments.”

The records reviewed by the inspector are identified in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdowns

a. Inspection Scope

The inspectors performed four inspection samples comprised of partial system walkdowns of accessible portions of trains of risk-significant mitigating systems equipment during times when the trains were of increased importance due to the redundant trains or other related equipment being unavailable. In addition, the inspectors reviewed CAPs associated with equipment alignment issues to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

The inspectors utilized the valve and electric breaker checklists to verify that the components were properly positioned and that support systems were lined up as needed. The inspectors also examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious performance deficiencies. The inspectors reviewed outstanding work orders (WOs) and CAPs associated with the trains to verify that those documents did not reveal issues that could affect train function. The inspectors used the information in the appropriate sections of the USAR to determine the functional requirements of the systems.

The inspectors verified the alignment of the following trains:

- diesel generator D6 during the unavailability of diesel generator D5 on April 13, 2005;
- A cooling water header during the isolation of the B cooling water header for planned maintenance on May 16, 2005;
- diesel generator D2 during the unavailability of diesel generator D1 on June 15, 2005; and
- 121 control room ventilation during the unavailability of the 122 control room ventilation system on June 20, 2005.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Protection Area Walkdowns

a. Inspection Scope

The inspectors conducted in-office and in-plant reviews of portions of the licensee's Fire Hazards Analysis and Fire Strategies to verify consistency between these documents and the as-found configuration of the installed fire protection equipment and features in the fire protection areas listed below. The inspectors selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the IPEEE; their potential to impact equipment which could initiate a plant transient; or their impact on the plant's ability to respond to a security event. The inspectors assessed the control of transient combustibles and ignition sources, the material and operational condition of fire protection systems and equipment, and the status of fire barriers. In addition, the inspectors reviewed CAPs associated with fire protection issues to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

The following eight fire areas were inspected by in-plant walkdowns supporting the completion of eight fire protection zone walkdown samples:

- Fire Area 20, safety-related bus 16 room on April 14, 2005;
- Fire Area 102, D6 diesel generator engine room on April 14, 2005;
- Fire Area 114, D6 diesel generator fuel oil day tank room on April 14, 2005;
- Fire Area 118, safety-related bus 26 room on April 14, 2005;
- Fire Area 128, safety-related bus 27 room on April 14, 2005;
- Fire Area 72, Unit 2 shield building annulus on May 11, 2005;
- Fire Area 71, Unit 2 reactor building on May 18, 2005; and
- Fire Area 18, Unit 1 and 2 relay room on May 19, 2005.

b. Findings

Introduction: The inspectors identified a Non-Cited Violation (NCV) of 10 CFR 50.48(a)(2)(I) having very low safety significance (Green) for storage of transient combustibles stored in the Unit 2 reactor building without required administrative controls.

Description: Inspectors identified that significant quantities of transient combustible materials were stored in the Unit 2 reactor building during refueling outage 2R23 without required administrative controls. The materials in the reactor building included six 55-gallon barrels of lubricating oil, storage shelves and racks of radiation protection materials (cloth, paper, and plastic contamination control supplies), bags of accumulated waste (cloth, paper, and plastic), temporary cables and hoses, and plastic shipping containers. Permits did not exist for the storage of these materials. Several potential ignition sources were identified including welding, grinding, and use of portable or temporary electrical equipment.

Analysis: Inspectors determined that the quantity of transient combustibles exceeded the quantities included in the Fire Hazard Analysis, F5, paragraph 5.2.4, which assumes that transient combustible are limited to the equivalent of 1000 pounds of wood and 10 gallons of acetone. The Fire Prevention Practices Procedure 5AWI 3.13.2 requires a Combustion Source Use Permit for transient combustible liquids greater than 2 gallons or large amounts of combustible material. The inspectors determined that failing to implement administrative controls for transient combustible materials in the reactor building was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issues Disposition Screening," issued January 14, 2004. The finding affected the reactor safety initiating events cornerstone objective to limit the likelihood of events that upset plant stability during shutdown, specifically protection against external factors (fire).

The inspectors completed a significance determination of the finding using IMC 0609, "Significance Determination Process," issued March 21, 2003, Appendix F, "Fire Protection Significance Determination Process," issued February 28, 2005. The finding was determined to be in the category, "Fire Prevention and Administrative Controls," and was assigned a LOW degradation rating, and therefore was determined to be of very low safety significance (Green).

Enforcement: 10 CFR 50.48(a)(2)(I) requires that each operating nuclear power plant implement a fire protection plan that includes administrative controls for fire prevention. Amendment Number 144 to Prairie Island License Number DPR-60, requires that an approved fire protection program shall be implemented and maintained. The USAR Section 10.3.1 describes the fire protection program and states that the results of the fire hazards analysis were incorporated into Operations Manual F5, Appendix F, "Fire Hazards Analysis." Operations Manual F5, Appendix F, section 5.2.4, limits the quantity of transient combustibles. Contrary to this requirement, significant quantities of transient combustible materials were found in the Unit 2 reactor building without the required administrative controls. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program with CAP 042539, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000306/2005004-02)

.2 Annual Fire Drill Observation

a. Inspection Scope

On April 20, 2005, inspectors observed an unannounced fire brigade drill. An oil fire was simulated at the Unit 1 generator hydrogen seal oil area. The inspectors observed the fire brigade's response at the scene of the simulated fire. This inspection effort completed the required annual fire drill observation sample.

The inspectors verified that the fire brigade donned the appropriate turnout gear and self-contained breathing apparatus; that plant personnel adequately controlled access to the affected area; that the fire brigade made a controlled approach to the simulated fire; that the fire brigade responded with sufficient equipment of the appropriate type to extinguish the fire; that communications between the fire brigade, fire brigade leader, and control room were clear and concise; that fire brigade members checked for victims and for fire propagation into other plant areas; and that the fire brigade correctly used fire fighting pre-plans. Additionally, the inspectors verified that the drill scenario was followed and that drill objectives and acceptance criteria were met. The inspectors attended the post drill critique and verified that weaknesses noted during the drill were discussed with the drill participants. The inspectors verified that the licensee was identifying fire protection issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

b. Findings

No findings of significance were identified.

.3 Loss of Fire Suppression Capability to the unit 1 and 2 Relay Room

a. Inspection Scope

On May 16, 2005, the inspectors began an investigation of the circumstances associated with the licensee's identification of a configuration control event that resulted in the loss of carbon dioxide fire suppression capability to the Unit 1 and 2 relay room. The inspectors began assessment of the event for risk significance in accordance with IMC 0609 "Significance Determination Process," dated March 21, 2003, Appendix F, "Fire Protection Significance Determination Process," dated February 28, 2005.

b. Findings

Introduction: The inspectors identified that the licensee failed to assess the significance of the loss of fire suppression capability to the Unit 1 and 2 relay room when the licensee found the carbon dioxide outlet valve, FP-14-1, one and a half turns from the fully closed position. Pending the results of the significance determination evaluation, this issue is being treated as an Unresolved Item (URI).

Description: On May 16, 2005, during a routine problem identification and resolution review, the inspectors identified that the licensee failed to assess the significance of a mispositioning event that resulted in loss of automatic fire suppression system to the Unit 1 and 2 relay room. The inspectors recognized the event as potentially risk significant and notified the licensee of the potential significance.

The inspector reviewed the licensee's investigation of the event noting that the licensee opened valve FP-14-1 upon discovery of its mispositioning on February 11, 2005, eliminating any immediate safety concern. The licensee's investigation found that FP-14-1 was isolated for a corrective maintenance activity to replace a Cardox system indicating light flasher unit under Work Order 0406433 on December 9, 2004. On January 29, 2005, SP 1200, "Fire Protection System Supply to Safety-Related Areas Valve Check," was performed by operators. The operator performing the check of valve FP-14-1 documented the position as open. However, the licensee's review of operating logs, work orders, system isolations, and procedures were unable to identify any time between December 9, 2004, and February 11, 2005, when FP-14-1 would have been closed. The licensee investigation concluded that the most likely cause was a failure to re-open the valve on December 9, 2004. Additionally, the licensee evaluated this event for reportability and concluded the event was not reportable. Since May 16, 2005, the licensee has reopened CAP 040948, initiated a root cause evaluation (RCE 000200), initiated CAP 043409 for the failure to identify the potential significance and appropriately assess the event, and commenced a detailed risk assessment and significance evaluation of the event with completion expected July 2005.

Analysis: The inspectors began assessment of the event for risk significance in accordance with IMC 0609 "Significance Determination Process," dated March 21, 2003, Appendix F, "Fire Protection Significance Determination Process," dated February 28, 2005. The Phase 1 evaluation established the following:

Finding Category	Fixed Fire Protection Systems
Degradation Rating	High
Duration Factor	1.0
Generic Fire Area Frequency - Cable Spreading Room Cables Plus Other Electrical Equipment	6E-3
Phase 1 Qualitative Screening Criteria	1E-6

Since the Generic Fire Area Frequency for the relay room multiplied by the Duration Factor resulted in a ΔCDF greater than the Phase 1 Qualitative Screening Criteria of 1E-6, the finding does not screen to Green and requires analysis using the Phase 2 Significance Determination Process.

Inspectors and Regional Senior Risk Analysts have commenced a Phase 2 analysis of the finding. Since the significance of this finding cannot yet be determined, this finding will be considered an Unresolved Item (URI 05000282/2005004-03; 05000306/2005004-03). This is also discussed briefly in Section 4OA2.1 of this report.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

On May 10 and 11, 2005, the inspectors performed an in-plant walkdown of the Unit 1 and 2 auxiliary feedwater pump rooms and the Unit 1 containment spray pump rooms completing one internal flood protection inspection sample. These areas of Unit 1 and 2 contain safety-related and risk significant equipment including both trains of the auxiliary feedwater pumps, instrument air compressors, and the Unit 1 containment spray pumps. The inspectors reviewed the applicable sections of the USAR, Individual Plant Examination, and plant procedures associated with internal flooding auxiliary feedwater pump rooms and adjacent areas. The inspectors verified by physical inspection that the licensee maintained the material condition of piping systems in these areas. The inspectors also verified that drain paths from these areas had been maintained and that there was no accumulation of loose materials that could plug drain paths.

The inspectors reviewed a CAP to verify that problems associated with plant equipment relied upon to prevent or minimize flooding were identified at an appropriate threshold, and that corrective actions commensurate with the significance of the issue were identified and implemented. The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08)

.1 Piping Systems ISI

a. Inspection Scope

From April 25, 2005, through May 20, 2005, the inspectors conducted a review of the implementation of the licensee's ISI program for monitoring degradation of the reactor coolant system (RCS) boundary and the risk significant piping system boundaries for Unit 2. The inspectors selected the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI required examinations and Code components in order of risk priority as identified in Section 71111.08-03 of the inspection procedure, based upon the ISI activities available for review during the onsite inspection period.

The inspectors observed the following two types of nondestructive examination activities:

- automated ultrasonic testing (UT) examination of the RCS nozzle-to-shell weld at the 148 degree azimuth location on the reactor vessel;
- automated UT examination of the safety injection system nozzle-to-shell weld at the 288 degree azimuth location on the reactor vessel;
- automated UT examination of the reactor vessel circumferential shell weld No. 2 and No. 4;
- visual testing (VT)-3 and VT-1 visual examinations of supports H-1 and H-4 on the 2-inch diameter cold leg resistance temperature detector takeoff line for RCS loop B;
- VT-1 visual examinations of the pressure retaining bolting for check valve 2SI-9-1; and
- VT-3 and VT-1 visual examinations of the support and integral attachments for the No. 21 motor driven auxiliary feedwater pump.

The inspectors observed these examinations to evaluate compliance with the ASME Code Section XI and Section V requirements and to determine if indications and defects were dispositioned in accordance with the ASME Code Section XI requirements.

The inspectors reviewed VT-3 visual examinations from the previous outage with relevant indications identified on sway strut supports CWH-26 and CWH-29 to determine if indications and defects were dispositioned in accordance with the ASME Code Section XI requirements.

The inspectors reviewed pressure boundary brazing activities for a Class 2 system which were completed since the beginning of the previous refueling outage, to determine if the brazing materials, acceptance and preservice examinations (e.g., brazing procedure qualification tensile tests and section quality tests) were performed in accordance with ASME Code Sections V, IX, and XI requirements. Specifically, the inspectors reviewed records of brazed joints associated with the tube repairs made on the No. 23 fan cooler unit.

The inspectors performed a review of ISI-related problems that were identified by the licensee and entered into the corrective action program, conducted interviews with licensee staff, and reviewed licensee corrective action records to determine if:

- the licensee had described the scope of the ISI related problems;
- the licensee had established an appropriate threshold for identifying issues;
- the licensee had evaluated industry generic issues related to ISI and pressure boundary integrity; and
- the licensee implemented appropriate corrective actions.

The inspectors performed these reviews to ensure 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.

The reviews as discussed above counted as one inspection sample.

b. Findings

.1 Inadequate Reactor Vessel Weld Examination Procedure

Introduction: A Green NCV of 10 CFR 50.55a(g)(4) was identified for the licensee's failure to specify a calibration block that met the ASME Code requirements in a procedure that performed UT examinations of the reactor vessel-to-flange welds for Unit 1 and Unit 2.

Description: On April 13, 2005, while performing preparation for the baseline ISI at Prairie Island Unit 2, the inspectors identified that the licensee had implemented an inadequate UT examination procedure for the reactor vessel flange-to-shell weld. The licensee's procedure WDI-SSP-082, "Manual Ultrasonic Examination of the Reactor Vessel Upper Shell to Flange Weld for Prairie Island," Revision 1, relied on a calibration block NSP-RV-1 which was not constructed in accordance with the ASME Code Section V, Article 4, requirements. Specifically, this calibration block exceeded the Code specified thickness (14 inches vice 9 inches), did not have reflectors (side drilled holes) located at the required locations (1/4T, 1/2T, and 3/4T (where T equals the calibration block thickness)), and it lacked a square notch type reflector.

The location of the side drilled holes within the calibration block supports the development of a distance amplitude correction (DAC) curve for UT system calibration. The DAC curve is then used in identification and characterization of potential crack indications observed during the UT examination. Without a properly established DAC curve, the UT examination of the vessel weld may not have effectively identified weld defects (e.g., cracks). In addition, the calibration block lacked a square notch reflector that was required to be located at the near and far sides of the calibration block. Without this notch, the licensee could not comply with the ASME Code requirement to compare the amplitude of UT indications identified during the examination with the UT calibration notch signals to estimate the depth of surface breaking flaws. Therefore, the inspectors were concerned that this non-Code compliant examination could result in failure to detect or properly size flaws in the reactor vessel flange-to-shell weld.

To address these deficiencies, the licensee elected to not credit Code volumetric coverage for the examination of the Unit 2 vessel flange-to-shell weld and documented this issue in the corrective action system (CAP 042091). Instead, the licensee intended to credit the UT examinations performed from the inside weld surface using automated equipment that was qualified in accordance with the ASME Code Section XI, Appendix VIII requirements to obtain a valid weld UT examination.

Analysis: The licensee's performance deficiency associated with this finding, is failure to incorporate the applicable Code requirements related to calibration of the UT equipment into procedure WDI-SSP-082. The inspectors compared this performance deficiency to the findings identified in Appendix E, "Examples of Minor Issues," of IMC 0612, "Power Reactor Inspections Reports," to determine whether the finding was minor. The inspectors concluded that none of the examples listed in Appendix E of IMC 0612 accurately represented this example. As a result, the inspectors compared this performance deficiency to the questions contained in

Section 3, "Minor Questions," of Appendix B of IMC 0612. The inspectors concluded that this finding was greater than minor, because if left uncorrected, it could have resulted in allowing unacceptable weld flaws to remain in-service and the licensee would have relied on this inadequate examination for credit towards completing the required Code weld volumetric coverage.

This finding was assigned to the barrier integrity cornerstone because it affected the barrier integrity cornerstone objective of RCS equipment and barrier performance. The inspectors determined that the finding could not be evaluated using the Significance Determination Process in accordance with NRC IMC 0609, "Significance Determination Process," because the SDP for the barrier integrity cornerstone only applied to degraded systems/components, not to deficiencies in the procedures that are designed to detect component degradation. Therefore, this finding was reviewed by a Regional Branch Chief in accordance with IMC 0612, Section 05.04c, who agreed with the inspectors, that this finding was of very low safety significance (Green). Because this non-Code UT procedure was identified prior to taking Code credit for this weld examination, and a separate Code qualified examination was conducted on the affected vessel weld, the inspectors determined that this finding was of very low risk significance.

<u>Enforcement</u>: On April 13, 2004, while performing preparations for the baseline inservice inspection procedure 71111.08, the inspectors identified an NCV of 10 CFR 50.55a(g)4.

Title 10 CFR 50.55a(g)4 required, in part, that throughout the service life of a boiling or pressurized water reactor facility, components classified as ASME Code Class 1, 2, and 3 must meet requirements of Section XI.

ASME Code Section XI (1989 Edition), paragraph IWA-2232 and Appendix I, I-2100 required that the "Ultrasonic examination of vessel welds greater than 2 inches thickness shall be conducted in accordance with Article 4 of Section V, ..."

ASME Code, Section V, Article 4, Paragraph T-441.1.3.1 required for the calibration block "A square notch shall also be used."

ASME Code, Section V, Article 4, Paragraph T-441.1.3.4 required a calibration block be used in accordance with Figure T-441.1. Figure T-441.1 specified side drilled holes be established at the 1/4T, 1/2T, and 3/4T locations.

ASME Code, Section V, Article 4, Paragraph T-441.1.3.4 required that for each weld thickness on the component must be represented by a block having a component thickness relative to the component weld as shown on Figure T-441.1. Figure T-441.1 specified a calibration block thickness of 9 inches or t (where t is the actual component weld thickness, which was 9 inches for the Prairie Island vessel flange-to-shell weld).

Contrary to these requirements, the inspectors identified that Step 6.1 of procedure WDI-SSP-082, "Manual Ultrasonic Examination of the Reactor Vessel Upper Shell to Flange Weld for Prairie Island," Revision 1, required "Prior to the examinations, the completed system to be utilized shall be calibrated on the appropriate calibration block (NSP-RV-1) for the examinations to be conducted." Calibration block NSP-RV-1, did not contain side drilled holes located at the 1/4T, 1/2T, and 3/4T locations, and did not contain a square notch reflector. Further, the calibration block thickness was 14 by 36 inches instead of 9 inches thick. This violation had existed since the procedure was approved on July 14, 2004. The inspectors concluded that this violation did not represent a safety concern as discussed above. Because of the very low safety significance of this finding and because the issue was entered into the licensee's corrective action program (CAP 042091), it is being treated as an NCV, consistent with Section VI.A.1 of the

Enforcement Policy (NCV 05000282/2005004-04; NCV 05000306/2005004-04).

.2 Pressurized Water Reactor Vessel Head Penetration ISI

a. Inspection Scope

The inspectors did not perform Section 02.02, “Pressurized Water Reactor Vessel Upper Head Penetration Inspection Activities,” of inspection procedure (IP) 71111.08 (reduction in one inspection sample), because the licensee replaced the Unit 2 vessel head during this outage and therefore no vessel head penetration inspections were performed.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

On May 3, 2005, and from May 11, 2005, through May 13, 2005, the inspectors reviewed the Unit 2 BACC inspection activities conducted pursuant to licensee commitments made in response to NRC Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary.”

The inspectors observed the licensee during BACC visual examinations of the reactor coolant and other borated systems conducted on May 3, 2005, to evaluate compliance with licensee BACC program requirements and 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requirements. In particular, the inspectors observed these examinations to determine if the licensee focused on locations where boric acid leaks can cause degradation of safety significant components and that degraded or non-conforming conditions were properly identified in the licensee’s corrective action system.

The inspectors reviewed engineering evaluations performed for boric acid found on RCS piping and components to verify that the minimum design code required section thickness had been maintained for the affected component(s). Specifically, the inspectors reviewed:

- Operability Recommendation (OPR) 000453 (CAP 032754) for a boric acid leak at valve 2RH-10-1, and
- OPR 000454 (CAP 032755) for a boric acid leak at valve 2RH-1-1.

The inspectors reviewed licencee corrective actions implemented for evidence of boric acid leakage to confirm that they were consistent with requirements of Section XI of the ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI. Specifically, the inspectors reviewed:

- CAP 039932, “As left condition of the reactor head after cleaning boric acid from conoseal leakage”; and
- CAP 037863, “1R23 leakage from instrument port conoseals.”

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

The reviews as discussed above counted as one inspection sample.

b. Findings

No findings of significance were identified.

.4 <u>Steam Generator (SG) Tube ISI</u>

a. <u>Inspection Scope</u>

From May 11, 2005, through May 19, 2005, the inspectors performed an on-site review of SG tube examination activities conducted pursuant to TS and the ASME Code Section XI requirements.

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

- in-situ SG tube pressure testing screening criteria and the methodologies used to derive these criteria were consistent with the Electric Power Research Institute (EPRI) TR-107620, "Steam Generator In-Situ Pressure Test Guidelines;"

- the in-situ SG tube pressure testing screening criteria were properly applied in terms of SG tube selection based upon evaluation of the list of tubes with measured/sized flaws;

- the numbers and sizes of SG tube flaws/degradation identified were consistent with that evaluated and expected in the licensee's SG Operational Assessment;

- the SG tube ET examination scope and expansion criteria were sufficient to identify tube degradation based on site and industry operating experience by confirming that the ET scope completed was consistent with the licensee's procedures, plant TS requirements and EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 6;"

- the SG tube ET examination scope included tube areas which represent ET challenges such as the tubesheet regions, expansion transitions and support plates;

- the licensee identified new tube degradation mechanisms;

- the licensee implemented repair methods which were consistent with the repair processes allowed in the plant TS requirements;

- the licensee primary-to-secondary leakage (e.g., SG tube leakage) was below 3 gallons per day for each SG during the last operating cycle;

- the licensee did an evaluation for unretrievable loose parts; and

- 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, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 6.

The inspectors performed a review of SG ISI-related problems that were identified by the licensee and entered into the corrective action program, and conducted interviews with licensee staff to determine if:

- the licensee had described the scope of the SG-related problems;
- the licensee had established an appropriate threshold for identifying issues;
- the licensee had evaluated industry generic issues related to SG tube integrity; and
- the licensee implemented appropriate corrective actions.

The inspectors performed these reviews to ensure 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.

The NRC inspectors concluded that the reviews discussed above did not count as a completed inspection sample as described in Section 71111.08-5 of the inspection procedure, but the sample was completed to the extent possible.

The specific activities which were not available for the NRC inspectors' review to complete the procedure sample and the basis for their unavailability is identified below.

- Procedure 71111.08, Steps 02.04.a.3 and 02.04.a.4 associated with review of in-situ pressure testing and tube performance criteria were not available for review because none of the degraded SG tubes met the screening requirements for pressure testing.

- Procedure 71111.08, Step 02.04.d associated with review of licensee activities for new SG tube degradation mechanisms was not available for review because no new tube degradation mechanisms were identified.

- Procedure 71111.08, Step 02.04.h associated with review of corrective actions for primary-to-secondary leakage greater than 3 gallons per day was not available for review because primary-to-secondary leakage was below this threshold during the previous operating cycle.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On June 20, 2005, the inspectors performed a quarterly review of licensed operator requalification training in the simulator, completing one licensed operator requalification inspection sample. The inspectors observed a crew during an evaluated exercise in the plant's simulator facility. The inspectors compared crew performance to licensee management expectations. The inspectors verified that the crew completed all of the critical tasks for each exercise scenario. For any weaknesses identified, the inspectors observed that the licensee evaluators noted the weaknesses and discussed them in the critique at the end of the session.

The inspectors assessed the licensee's effectiveness in evaluating the requalification program, ensuring that licensed individuals would operate the facility safely and within the conditions of their licenses, and evaluated licensed operator mastery of high-risk operator actions. The inspection activities included, but were not limited to, a review of high-risk activities, emergency plan performance, incorporation of lessons learned, clarity and formality of communications, task prioritization, timeliness of actions, alarm response actions, control board operations, procedural adequacy and implementation, supervisory oversight, group dynamics, interpretations of TS, simulator fidelity, and licensee critique of performance.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed repetitive maintenance activities to assess maintenance effectiveness, including maintenance rule (10 CFR 50.65) activities, work practices, and common cause issues. The inspectors performed two issue/problem-oriented maintenance effectiveness samples completing a total of two samples. The inspectors assessed the licensee's maintenance effectiveness associated with repetitive problems on the following SSCs:

- Unit 2 diesel generator D5 and D6 cylinder and piston indications; and
- Unit 1 and 2 volume control tank level transmitter failures.

The inspectors reviewed the licensee's maintenance rule evaluations of equipment failures for maintenance preventable functional failures and equipment unavailability time calculations, comparing the licensee's evaluation conclusions to applicable Maintenance Rule (a)1 performance criteria. Additionally, the inspectors reviewed scoping, goal-setting (where applicable), performance monitoring, short-term and long-term corrective actions, functional failure definitions, and current equipment performance status.

The inspectors reviewed CAPs for significant equipment failures associated with electrical equipment problems for risk significant and safety-related mitigating equipment to ensure that those failures were properly identified, classified, and corrected. The inspectors reviewed other CAPs to assess the licensee's problem identification threshold for degraded conditions, the appropriateness of specified corrective actions, and that the timeliness of the actions were commensurate with the significance of the identified issues.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed risk assessments for four planned and two emergent maintenance activities associated the following combinations of equipment unavailability completing six risk assessment and emergent work control inspection samples:

- the simultaneous unavailability of diesel generator D5, 22 charging pump, and volume control system valve 2VC-21-13 on April 11, 2005;
- the simultaneous unavailability of the Unit 2 intake bay (21 cooling water pump and 121 screenwash pump), electrical buses 221/222, load sequencers for bus 16 and bus 26, and diesel generator D2, on May 9, 2005;
- the simultaneous unavailability of the Unit 2 intake bay (21 cooling water pump and 121 screenwash pump), loop B cooling water header, 12 component cooling water heat exchanger, 12 safety injection pump, D2 diesel generator, 122 control room chiller, and the 122 safeguards traveling screen on May 16, 2005;
- the emergent failure of cooling water valve CW-19-6 with the unavailability of Unit 2 intake bay (21 cooling water pump and 121 screenwash pump) results in an orange risk condition on Unit 1 on May 20, 2005;
- the simultaneous unavailability of the A cooling water header and the Blue Lake transmission line on June 14, 2005; and
- the emergent increase in Unit 2 risk due to severe thunderstorms with the unavailability of 122 control room ventilation, and cooling water valve CL-19-6 on June 20, 2005.

During these reviews, the inspectors compared the licensee's risk management actions to those actions specified in the licensee's procedures for the assessment and management of risk. The inspectors verified that evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and minimize the duration where practical, and that contingency plans were in place where appropriate. The inspectors used the licensee's daily configuration risk assessment records, observations of shift turnover meetings, observations of daily plant status meetings, and observations of shiftly outage meetings to verify that the equipment configurations had been properly listed, that protected equipment had been identified and was being controlled where appropriate, and that significant aspects of plant risk were communicated to the necessary personnel. The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance Related to Non-Routine Plant Evolutions and Events (71111.14)

.1 Technical Specification Required Shutdown for the Repair of the D5 Diesel Generator

a. Inspection Scope

On April 15, 2005, the inspectors reviewed licensee personnel performance during a shutdown of Unit 2 required by TS for the repair the D5 diesel generator engines. The review constituted one inspection procedure sample. The inspectors observed the performance of operations personnel in the control room during the planned but non-routine evolution. The inspectors compared the actions of plant personnel to the action required by TS and plant procedures. The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Loss of Refueling Water Storage Tank Inventory to the Containment Recirculation Sump

a. Inspection Scope

On April 27, 2005, the inspectors reviewed licensee personnel performance following notification from personnel in containment that the containment recirculation sump was overflowing. The review constituted one inspection procedure sample. The inspectors observed the performance of operations personnel in the control room during the unplanned and non-routine evolution. The inspectors compared the actions of plant personnel to the action required by TS and plant procedures. The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the technical adequacy of three operability evaluations completing three operability evaluation inspection samples. The inspectors conducted these inspections by in-office review of associated documents and in-plant observations of affected areas and plant equipment. The inspectors compared degraded or nonconforming conditions of risk-significant structures, systems, or components associated with mitigating systems against the functional requirements described in TS, the USAR, and other design basis documents; determined whether compensatory measures, if needed, were implemented; and determined whether the evaluation was consistent with the requirements of 5AWI 3.15.5, “Operability Determinations.” The following operability evaluations were reviewed:

- OPR 000545, that documented the operability of D6 diesel generator following discovery of abnormal wear indication in D5 diesel generator on April 22, 2005;
- OPR 000546, that documented the operability of decay heat removal capability following a heavy load drop over the reactor vessel; and
- Prompt Operability for CAP 042996, that documented the operability of the RCS temperature indication following discovery that the resistance temperature detector bypass loop flow orifice was installed backwards.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (OWAs) (71111.16)

.1 Unit 2 Diesel Generator Crankcase Pressure Indication OWA

a. Inspection Scope

On April 22, 2005, the inspectors reviewed one operator workaround that had not been evaluated by the licensee and that had been formalized as long-term corrective action for a degraded or non-conforming condition associated with the D5 and D6 diesel generator crankcase manometers to determine if the mitigating system function was affected. Specifically, the inspectors evaluated if the operator's ability to implement abnormal and emergency operating procedures was affected by the workaround. The inspectors also reviewed OWA for increased potential for personnel error including:

- required operations contrary to past training or require more detailed knowledge of the system than routinely provided;
- required a change from longstanding operational practices;
- required operation of system or component in a manner that is different from similar systems or components;
- created the potential for the compensatory action to be performed on equipment or under conditions for which it is not appropriate;
- impaired access to required indications, increase dependence on oral communications, or require actions under adverse environmental conditions; or
- required the use of equipment and interfaces that had not been designed with consideration of the task being performed.

b. Findings

No findings of significance were identified.

.2 Cumulative Effect of OWAs

a. Inspection Scope

On April 13, 2005, the inspectors performed an in-office review of the cumulative effect of all identified OWAs to determine if there was a significant impact on plant risk or on the operators' ability to respond to a transient or an accident. The inspection effort completed one operator workaround inspection sample. The inspectors used related abnormal and emergency operating procedures as well as the documents listed in the Attachment to evaluate the list of OWAs.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed permanent changes to the primary chemistry program lithium and hydrogen limits completing one permanent plant modification inspection sample. Specifically, this change revises the USAR's maximum limit for RCS hydrogen to 50 cubic centimeters per kilogram and lithium concentrations to 5 parts per million for the first 150 mega-watt days per metric ton of uranium.

The inspectors performed an in-office review of the change package including the 50.59 evaluation, safety evaluation, EPRI Pressurized Water Primary Chemistry Guidelines, and Westinghouse recommendations. The inspectors reviewed affected parameters to verify that design and/or licensing bases and the performance capability of risk significant structures, systems or components were not degraded through the change. Inspector reviewed emergency/abnormal procedures as well as key safety functions, and the operator's ability to respond to a loss of key safety function and verified that the changes to the primary chemistry resulted in no adverse affects.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors performed seven assessments of post-maintenance testing completing seven post-maintenance test inspection samples. The inspectors selected post-maintenance tests associated with important mitigating and barrier integrity systems to ensure that the testing was performed adequately, demonstrated that the maintenance was successful, and that operability of associated equipment and/or systems was restored. The inspectors conducted this inspection by in-office review of documents and in-plant walkdowns of associated plant equipment. The inspectors observed and assessed the post-maintenance testing activities for the following maintenance activities:

- diesel generator D5 following major corrective maintenance (complete engine rebuild) on April 23, 2005;
- 23 containment fan coil unit following major corrective maintenance (replacement of coil faces) on May 18, 2005;

- diesel generator D6 following boroscopic inspection of engine cylinders on May 15, 2005;
- 22 safety injection pump following motor replacement on May 31, 2005;
- replacement of solenoid valve SV-37465 following a failure of the containment fan coil unit to swap to the safeguards water supply during the integrated safety injection test on June 6, 2005;
- 22 residual heat removal pump mechanical seal replacement following observation of seal leakage on June 9, 2005; and
- Unit 2 A main steam isolations valve following the failure of the valve to meet surveillance procedure acceptance criteria on June 13, 2005.

The inspectors reviewed the appropriate sections of the TS, USAR, and maintenance documents to determine the systems' safety functions and the scope of the maintenance. The inspectors also reviewed CAPs to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

.1 Containment Fan Coil Unit Forced Outage

a. Inspection Scope

The inspectors observed the licensee's performance during a Unit 2 maintenance outage conducted between March 30 and April 3, 2005, to repair containment fan coil units (CFCU). These inspection activities represent one forced outage inspection sample.

This inspection consisted of a in-office and in-plant review of outage activities performed by the licensee. The inspectors conducted in-office reviews of outage related documentation and in-plant observations of the following outage activities:

- attended outage management turnover meetings to verify that the current shutdown risk status was accurate, well understood, and adequately communicated;
- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- observed the operability of RCS instrumentation and compared channels and trains against one another;
- reviewed of selected issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance; and
- observed the reactor start up from the control room.

b. Findings

No findings of significance were identified.

.2 Unit 2 Technical Specification Required Shutdown and Forced Outage for an Inoperable D5 Diesel Generator

a. Inspection Scope

The inspectors observed the licensee's performance during a Unit 2 maintenance outage conducted between April 16 and May 2, 2005, to replace cylinder liners and pistons on the D5 diesel generator due to observed high crankcase pressure. These inspection activities represent one forced outage inspection sample. On May 2, 2005, the licensee made the decision to commence a planned refueling outage at 6:00 a.m..

This inspection consisted of a in-office and in-plant review of outage activities performed by the licensee. The inspectors conducted in-office reviews of outage related documentation and in-plant observations of the following outage activities:

- observed the reactor shutdown and RCS cooldown;
- attended outage management turnover meetings to verify that the current shutdown risk status was accurate, well understood, and adequately communicated;
- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- observed the operability of RCS instrumentation and compared channels and trains against one another; and
- reviewed of selected issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance.

b. Findings

No findings of significance were identified.

.3 Refueling and Reactor Head Replacement Outage

a. Inspection Scope

The inspectors observed the licensee's performance during the Unit 2 refueling outage 2R23 conducted between May 2 and June 10, 2005, following a continuation of a forced outage to replace D5 cylinder liners and pistons. This constitutes one refueling inspection sample.

This inspection consisted of an in-office and in-plant review of outage activities performed by the licensee. The inspectors conducted in-office reviews of outage related documentation and in-plant observations of the following outage activities daily:

- attended outage management turnover meetings to verify that the current shutdown risk status was accurate, well understood, and adequately communicated;
- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- observed the operability of RCS instrumentation and compared channels and trains against one another;
- observed reduced inventory operations;
- conducted frequent walkdowns in the Unit 2 containment;
- observe ongoing work activities and foreign material exclusion control;
- reviewed selected issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance;
- observed RCS fill and venting;
- observed RCS heat up and pressurization;
- observed start up operations including the approach to critical and criticality;
- observed power ascension; and
- reviewed post-refueling start up testing results.

Additionally, the inspectors performed in-plant or observation or in-office review of the following specific activities:

- conducted a walkdown of plant areas which are inaccessible during power operations for evidence of leakage and integrity of structures, systems, and components in accordance with IP 71111.20, Section 02.02 in the volume control tank room, and the letdown heat exchanger rooms;
- observed the reload of fuel into the reactor from the containment, spent fuel pool area, and the control room;
- observed core inventory verification; and
- conducted as-found boric acid walkdowns of the RCS in accordance with IP 71111.08, Section 02.03.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

During this inspection period, the inspectors completed nine inspection samples. SP 2070 completed the quarterly inservice testing inspection requirement of risk-significant valves. SP 2072.29A completed the surveillance inspection requirement to review a local leak rate test each refueling outage. The inspectors selected the following surveillance testing activities:

- SP 1307, D2 Diesel Generator 6-Month Fast Start Test, on April 4, 2005;
- SP 2295, D5 Diesel Generator 6-Month Fast Start Test, on April 25, 2005;

- SP 2407, Leakage Examination of Canopy Seals, Mechanical Joints, and Other Pressure Retaining Components on the Reactor Vessel Head, on May 2, 2005;
- SP 2405, Mid-Cycle and Refueling Outage Boric Acid Corrosion Examinations Inside Containment, on May 3, 2005;
- SP 2083, Unit 2 Integrated Safety Injection Test With a Simulated Loss of Offsite Power, on May 4, 2005;
- SP 2177, Core Inventory Verification, on May 23, 2005;
- SP 2072.29A, Local Leak Rate Test of Penetration (29A) Containment Spray on May 28, 2005;
- SP 2070, Reactor Coolant System Integrity Test at Normal Operating Pressure and Temperature on June 9, 2005; and
- SP 2750, Post-Outage Containment Close-Out Inspection on June 9, 2005.

During completion of the inspection samples, the inspectors observed in-plant activities and reviewed procedures and associated records to verify that:

- preconditioning does not occur;
- effects of the testing had been adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria was clearly stated, demonstrated operational readiness, and was consistent with the system design basis;
- plant equipment calibration was correct, accurate, properly documented, and the calibration frequency was in accordance with TS, 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 frequency met TS requirements to demonstrate operability and reliability;
- the tests were performed in accordance with the test procedures and other applicable procedures;
- jumpers and lifted leads were controlled and restored where used;
- test data/results were accurate, complete, and valid;
- test equipment was removed after testing;
- where applicable for in-service testing activities, testing was performed in accordance with the applicable version of Section XI, ASME Code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data have been accurately incorporated in the test procedure;
- 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 in the corrective action program.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors conducted in-plant observations of the physical changes to the equipment and an in-office review of documentation associated with one temporary modification completing one temporary modification inspection sample. As part of this inspection, the documents in the Attachment were utilized to evaluate the potential for an inspection finding.

The inspectors reviewed temporary modification 04T175 associated with a temporary installation of air bottles to supplement the air accumulator for each pressurizer power operated relief valve (PORV) on May 12 and 13, 2005.

The inspection activities included, but were not limited to, a review of design documents, safety screening documents, and the USAR to determine that the temporary modification was consistent with modification documents, drawings, and procedures. The inspectors also reviewed the post-installation test results to confirm that tests were satisfactory and the actual impact of the temporary modification on the permanent system and interfacing systems were adequately verified. The inspectors also reviewed the CAPs listed in the Attachment to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed a licensed shift operating crew perform an “as-found” exercise on the simulator on June 27, 2005, completing one emergency planning simulator exercise sample. The inspectors observed activities in the control room simulator that include event classification and notification and attended the post-exercise critique. The inspectors evaluated the drill performance and verified that licensee evaluators’ observations were consistent with those of inspectors and that deficiencies were entered into the corrective action program.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review of Licensee Performance Indicators for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors reviewed the licensee's occupational exposure control cornerstone performance indicators (PIs) to determine whether or not the conditions surrounding the PIs had been evaluated, and identified problems had been entered into the corrective action program for resolution. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following three radiologically significant work areas within radiation areas, high radiation areas, and airborne radioactivity areas in the plant and reviewed work packages, which included associated licensee controls and surveys of these areas to determine if radiological controls including surveys, postings, and barricades were acceptable:

- reactor vessel head replacement;
- containment fan cooler replacement; and
- steam generator eddy current testing.

This review represented one sample.

The inspectors reviewed the radiation work permits (RWPs) and work packages used to access these three areas and other high radiation work areas to identify the work control instructions and control barriers that had been specified. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Workers were interviewed to verify that they were aware of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed. This review represented one sample.

The inspectors walked down and surveyed (using an NRC survey meter) these three areas to verify that the RWP, procedure, and engineering controls were in place; that licensee surveys and postings were complete and accurate; and that air samplers were properly located. This review represented one sample.

The inspectors reviewed procedures and methods for controlling airborne radioactivity areas to verify barrier integrity and engineering controls performance (e.g., high efficiency particulate air ventilation system operation) and to determine if there was a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. There were no airborne areas created as a result of major activities observed during the inspection. This review represented one sample.

Work areas having a history of, or the potential for, airborne transuranics were evaluated to verify that the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection. This review represented one sample.

The adequacy of the licensee’s internal dose assessment process for internal exposures greater than 50 millirem committed effective dose equivalent was assessed. There were no internal exposures greater than 50 millirem. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee’s self-assessments, audits, Licensee Event Reports, and Special Reports related to the access control program to verify that identified problems were entered into the corrective action program for resolution. This review represented one sample.

The inspectors reviewed 15 corrective action reports related to access controls and four high radiation area radiological incidents (non-performance indicators identified by the licensee in high radiation areas less than 1R/hr). Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of NCVs tracked in the corrective action system; and
- Implementation/consideration of risk significant operational experience feedback.

This review represented one sample.

The inspectors evaluated the licensee’s process for problem identification, characterization, and prioritization and verified that problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies. This review represented one sample.

The inspectors reviewed licensee documentation packages for all PI events occurring since the last inspection to determine if any of these PI events involved dose rates greater than 25 R/hr at 30 centimeters or greater than 500 R/hr at 1 meter. Barriers were evaluated for failure and to determine if there were any barriers left to prevent personnel access. There were no PI events occurring since the last inspection. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following three jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- reactor vessel head replacement;
- containment fan cooler replacement; and
- steam generator eddy current testing.

The inspectors reviewed radiological job requirements for these three activities, including RWP requirements and work procedure requirements, and attended As Low As Reasonably Achievable (ALARA) job briefings. This review represented one sample.

Job performance was observed with respect to these requirements to verify that radiological conditions in the work area were adequately communicated to workers through pre-job briefings and postings. The inspectors also verified the adequacy of radiological controls including required radiation, contamination, and airborne surveys for system breaches; radiation protection job coverage which included audio and visual surveillance for remote job coverage; and contamination controls. This review represented one sample.

Radiological work in high radiation work areas having significant dose rate gradients was reviewed to evaluate the application of dosimetry to effectively monitor exposure to personnel and to verify that licensee controls were adequate. Specifically, the steam generator eddy current work was reviewed. This work area involved an area where the dose rate gradients were severe which increased the necessity of providing multiple dosimeters and/or enhanced job controls. This review represented one sample.

b. Findings

No findings of significance were identified.

.5 High Risk Significant, High Dose Rate High Radiation Area and Very High Radiation Area Controls

a. Inspection Scope

The inspectors held discussions with the Radiation Protection Manager concerning high dose rate/high radiation area and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection, in order to verify that any procedure modifications did not substantially reduce the effectiveness and level of worker protection. This review represented one sample.

The inspectors discussed with Radiation Protection supervisors the controls that were in place for special areas that had the potential to become very high radiation areas during certain plant operations, to determine if these plant operations required communication beforehand with the Radiation Protection group, so as to allow corresponding timely actions to properly post and control the radiation hazards. This review represented one sample.

The inspectors conducted plant walkdowns to verify the posting and locking of entrances to high dose rate high radiation areas and very high radiation areas. This review represented one sample.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and evaluated whether workers were aware of the significant radiological conditions in their workplace, of the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present. This review represented one sample.

The inspectors reviewed radiological problem reports which found that the cause of the event was due to radiation worker errors to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. These problems, along with planned and taken corrective actions were discussed with the Radiation Protection Manager. This review represented one sample.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation protection technician performance with respect to radiation protection work requirements and evaluated whether they were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities. This review represented one sample.

The inspectors reviewed radiological problem reports which found that the cause of the event was radiation protection technician error to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. This review represented one sample.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

.1 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities ranked by estimated exposure that were in progress and reviewed the following three work activities of highest exposure significance:

- reactor vessel head replacement;
- containment fan cooler replacement; and
- steam generator eddy current testing.

This review represented one sample.

For these three activities, the inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures, and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances. This review represented one sample.

The inspectors compared the results achieved including dose rate reductions and person-rem used with the intended dose established in the licensee's ALARA planning for these three work activities. Reasons for inconsistencies between intended and actual work activity doses were reviewed. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Declared Pregnant Workers

a. Inspection Scope

The inspectors reviewed dose records of declared pregnant workers for the current assessment period to verify that the exposure results and monitoring controls employed by the licensee complied with the requirements of 10 CFR Part 20. At the time of the inspection, there were two declared pregnant workers. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolutions

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, and Special Reports related to the ALARA program since the last inspection to determine if the licensee's overall audit program's scope and frequency for all applicable areas under the occupational cornerstone met the requirements of 10 CFR 20.1101. This review represented one sample.

b. Findings

No findings of significance were identified.

2PS2 Radioactive Material Processing and Transportation (71122.02)

.1 Waste Characterization and Classification of the Reactor Pressure Vessel Head

a. Inspection Scope

The inspectors reviewed the licensee's waste stream radiochemical sample analysis results, radiological surveys, and shielding and source term calculations that were used to develop the Class "A" waste characterization of the Reactor Pressure Vessel Head (RPVH). These reviews were conducted to verify that the licensee's characterization assured compliance with 10 CFR 61.55 and 10 CFR 61.56, as required by Appendix G of 10 CFR Part 20. Additionally, the inspectors reviewed the licensee's calculations used to determine the Department of Transportation sub-typing for the shipment of the RPVH, so as to verify the Low Specific Activity-II sub-typing complied with 49 CFR Parts 172, 173, and 177. No samples under the baseline inspection procedure were completed by this review.

b. Findings

No findings of significance were identified.

.2 Shipment Preparation and Shipping Records for the RPVH

a. Inspection Scope

The inspectors reviewed the licensee's procedures and documentation for shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and licensee verification of shipment readiness for the shipment of the RPVH to the low-level radioactive waste disposal facility, Envirocare of Utah, Inc., in Clive, Utah. The inspectors selectively verified that the requirements of 10 CFR Parts 20 and 61 and those of the Department of Transportation in 49 CFR 170-189 were met for the RPVH shipment to Envirocare. This review represented one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As 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 corrective action program at an appropriate threshold, that adequate attention was given to ensure timely corrective actions, and that adverse trends were identified and addressed. This does not count as an annual sample.

b. Findings

On May 16, 2005, during a routine problem identification and resolution review, the inspectors identified that the licensee failed to assess the significance of a mispositioning event that resulted in loss of automatic fire suppression system to the Unit 1 and 2 relay room. The inspectors recognized the event as potentially risk significant with respect to fire protection of the relay room and notified the licensee of the potential significance. This finding will be treated as an Unresolved Item pending determination of significance. See Section 1R05.3 of this report for a more detailed discussion of this finding.

.2 Annual Problem Identification and Resolution Sample

a. Inspection Scope

During the week of June 26, 2005, the inspectors selected a corrective action program issue for detailed review completing one problem identification and resolution annual inspection sample. The inspectors selected an licensee identified issue associated with the establishment of a potential chemical and volume control system configuration during the replacement of boric acid transfer pump seals that would result in an inadvertent dilution of the RCS if left uncorrected. This condition was entered into the licensee's corrective action program with CAP 039236.

The inspectors conducted a review of the previously referenced CAPs and other related corrective action program documents in order to assess the effectiveness of the licensee's efforts to correct the identified problem. The inspectors placed particular attention on the review of the licensee's corrective actions taken to address the noted deficiencies and the effectiveness of those actions. The inspectors also ensured that the licensee had identified the full extent of the issue, conducted an appropriate evaluation, and that licensee-identified corrective actions were appropriately prioritized. The key documents reviewed by the inspectors associated with this inspection are listed in the Attachment to this inspection report.

b. Findings and Observations

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a semi-annual review of licensee trending activities to verify that emerging adverse trends that could indicate the existence of a more significant safety issue were adequately identified, were entered into the licensee's corrective action program at an appropriate threshold, and that timely corrective actions were implemented. This inspection effort completed one semi-annual trending inspection sample. The effectiveness of the licensee trending activities were assessed by comparing trends identified by the licensee with those issues identified by the NRC during the conduct of routine plant status and baseline inspections. The inspectors performed the inspection by in-office review of licensee corrective action program and other reports, including the following:

- trend reports;
- performance indicators;
- equipment problem lists;
- rework lists;
- system health reports;
- program health reports;
- maintenance rule reports;
- corrective action program document searches of risk significant structures, systems and components; and
- corrective action program document searches by key words.

This does not count as an annual inspection sample.

b. Findings

No findings of significance were identified.

4OA3 Event Followup (71153)

a. Inspection Scope

LER 05000282/2005-001-00: Discovery of Single Failure Vulnerability of Unit 1 Safeguards Buses

On February 5, 2005, a review of an event reported at Crystal River resulted in the determination that the Prairie Island Unit 1 safeguards buses had a single failure vulnerability due to current transformer circuits for the source breakers on common wires which fed metering equipment. Failure in the common portion of the current transformer circuit could actuate an overcurrent relay in each bus causing a lockout of both safeguards buses. Plant operators declared Unit 1 safeguards buses 15 and 16 inoperable and declared one path from the grid inoperable. The buses were transferred to an alternate source, the relaying disconnects were opened, and the buses were declared operable. On February 8, 2005, a temporary modification of the relaying scheme was implemented. The inspectors reviewed the licensee's apparent cause evaluation, the corrective actions implemented and planned, and compliance with requirements. LER 05000282/2005001-00 is closed to URI 05000282/2005004-05.

b. Findings

Introduction: The inspectors determined that the licensee failed to identify the introduction of the single failure vulnerability when bus 15 and 16 metering circuits were added as part of the station blackout modification in 1989. A potential violation of 10 CFR 50, Appendix B, Criterion III, for failure to identify a single failure vulnerability of safety-related equipment during a modification. Pending the results of the significance determination evaluation, this issue is being treated as an Unresolved Item .

Description: Unit 1 safeguards buses 15 and 16 are required to mitigate the consequences of an accident because they supply 4KV electrical power to safety-related equipment. These buses are required to meet single failure criterion. Buses 15 and 16 are tied together with a secondary current transformer on common wires that feeds metering equipment. A failure in the common portion of this current transformer circuit could result in current great enough to actuate an overcurrent relay, that would actuate the lockout relays for both buses 15 and 16, resulting in a total loss of all safeguards alternating current (AC) power to Unit 1. The metering portion of the circuit were added as part of the Station Blackout modification in 1989. The licensee's apparent cause evaluation states that the apparent cause is a failure of the modification process to identify the potential single failure vulnerability. Additionally, the licensee's Appendix R safe shutdown circuit analysis also failed to identify the cross train single failure potential.

Analysis: Inspectors determined that the single failure vulnerability did not comply with Section 8.1 of the USAR, which requires the design of these circuits to comply with

General Design Criteria 39. The inspectors determined that the introduction of a single failure vulnerability was a performance deficiency warranting a significance evaluation because the design failed to meet a requirement and the cause was reasonably within the licensee's ability to foresee and correct and could have been prevented. The inspectors also concluded that the issue was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issues Disposition Screening," issued January 14, 2004, since the failure to meet single failure design criteria for safety-related buses 15 and 16 could reasonably be viewed as a precursor to a significant event.

The inspectors began the assessment of the bus 15 and 16 single failure vulnerability for risk significance in accordance with IMC 0609 "Significance Determination Process," dated March 21, 2003, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated December 1, 2004. Phase 1 significance determination performed using IMC 609, Appendix A, Attachment 1, " Users Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations," Phase 1 worksheets resulted in the need for a Phase 2 evaluation since both the initiating event and mitigating system cornerstones were affected. Inspectors and Regional Senior Risk Analysts have commenced a Phase 2 analysis. Since the significance of this finding cannot yet be determined, this finding will be considered an Unresolved Item (URI 05000282/2005004-05).

4OA5 Other Activities

.1 Reactor Vessel Head Replacement Inspection (IP 71007)

a. Inspection Scope

From April 25, 2005, through April 29, 2005, and May 11, 2005, through May 19, 2005, regional inspectors performed an on-site review of preservice nondestructive examination records for the replacement reactor pressure vessel head in accordance with Section 02.05.e of IP 71007, "Reactor Vessel Head Replacement Inspection." The inspectors' review was performed to confirm that the required preservice examinations were conducted and that appropriate acceptance criteria had been applied to the replacement vessel head in accordance with the requirements of Section XI and Section III of the ASME Code, 1998 Edition through 2000 Addenda.

Resident inspectors performed an in-office review of the replacement head foreign material exclusion, lifting, and rigging procedures; observed the replacement head lift on May 25, 2005; and reviewed reactor head startup testing results including multiple rod drop testing, control rod drive mechanism timing test while cold, and control rod drive mechanism timing test while hot. The inspectors compared the actual results to predicted results and acceptance criteria contained in plant procedures to verify that the desired performance was achieved.

The records reviewed by the inspectors are identified in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 Final Performance Testing Review of the Unit 1 Replacement Steam Generators (IP 50001)

a. Inspection Scope

The inspectors reviewed replacement steam generator thermal performance results with the steam generator replacement project engineer. Final review of steam generator performance was delayed due to the inability to achieve 100 percent power on Unit 1 due to hydrogen seal problems on the main generator during the 4th quarter of 2004. During the 1st quarter of 2005, the licensee shutdown Unit 1 and completed the required repairs. Final performance data was taken and evaluated by the licensee. The inspectors compared the actual results to predicted results to verify no significant differences existed.

b. Findings

The information gathered during this TI was forwarded to the office of NRR.

.3 Operational Readiness of Offsite Power (Temporary Instruction 2515/163)

a. Inspection Scope

The objective of Temporary Instruction (TI) 2515/163, "Operational Readiness of Offsite Power," was to confirm, through inspections and interviews, the operational readiness of offsite power systems in accordance with NRC requirements. From May 2 through 13, 2005, the inspectors reviewed licensee procedures and discuss the attributes identified in TI 2515/163 with licensee personnel. The results of the inspectors' review included documenting observations and conclusions in response to the questions identified in TI 2515/163.

b. Observations

Summary: The licensee meets NRC requirements for managing the operational readiness of offsite power systems.

Evaluation of Inspection Requirements

In accordance with the requirements of TI 2515/163, inspectors evaluated licensee procedures against the attributes discussed below.

The operating procedures that the control room operator uses to assure the operability of the offsite power have the following attributes:

1. Identify the required control room operator actions to take when notified by the transmission system operator (TSO) that post-trip voltage of the offsite power at the NPP will not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply.

2. Identify the compensatory actions the control room operator is required to perform if the TSO is not able to predict the post-trip voltage at the NPP for the current grid conditions.

3. Identify the notifications required by 10 CFR 50.72 for an inoperable offsite power system when the nuclear station is either informed by its TSO or when an actual degraded voltage condition is identified.

The procedures to ensure compliance with 10 CFR 50.65(a)(4) have the following attributes:

1. Direct the plant staff to perform grid reliability evaluations as part of the required maintenance risk assessment before taking a risk-significant piece of equipment out-of-service to do maintenance activities.

2. Direct the plant staff to ensure that the current status of the offsite power system has been included in the risk management actions and compensatory actions to reduce the risk when performing risk-significant maintenance activities or when Loss of Offsite Power or Station Blackout mitigating equipment are taken out-of-service.

3. Direct the control room staff to address degrading grid conditions that may emerge during a maintenance activity.

4. Direct the plant staff to notify the TSO of risk changes that emerge during ongoing maintenance at the nuclear power plant.

The procedures to ensure compliance with 10 CFR 50.63 have the following attribute:

1. Direct the control room operators on the steps to be taken to try to recover offsite power within the Station Blackout coping time.

c. Findings

No findings of significance were identified.

.4 Transportation of Reactor Control Rod Drives in Type A Packages (TI 2515/161)

a. Inspection Scope

The inspector conducted interviews and record reviews to verify that: (1) the licensee had undergone refueling activities during calender year 2002; and (2) did not ship irradiated control rod drive mechanisms in DOT Specification 7A, Type A packages.

b. Findings

No findings of significance were identified.

.5 RVCH and CRDM Housing Replacement (IP 71007)

The original penetration nozzles were fabricated from Inconel Alloy 600 material. These nozzles were welded to the RVCH with a partial penetration weld fabricated from Inconel Alloy 182 weld filler metal. In recent years, several pressurized water reactors have experienced pressure boundary leakage caused by primary water stress corrosion cracking of these materials.

The design of the replacement RVCH is similar to the original, with some notable exceptions as follows:

- the new RVCH is constructed from a single piece forging which eliminates the dome-to-flange weld;
- the new RVCH design eliminates canopy seal welds;
- the new RVCH design eliminates the part length CRDM penetrations; and
- the use of Inconel Alloy 600 was prohibited in fabrication of the new RVCH. For example, the penetration tube material was changed from Inconel Alloy 600 to Inconel Alloy 690 which is more resistant to primary water stress corrosion cracking.

a. Inspection Scope

From April 25, 2005, through April 29, 2005, and from May 23, 2005, through May 27, 2005, the inspector reviewed the licensee’s design changes associated with the replacement efforts.

The inspector reviewed certified design specifications, certified design reports, ASME Code reconciliation reports, fabrication deviation notices, non-conformance reports, and design calculations to confirm that the replacement RVCH and CRDM housings were in compliance with the requirements of ASME Boiler and Pressure Vessel Code, Section III, Subsection NB (1998 Edition including addenda through 2000 Addendum). The inspector confirmed that the design specifications and design reports were certified by registered professional engineers competent in ASME Code requirements. The inspector confirmed that adequate documentation existed to demonstrate the certifying registered professional engineers were qualified in accordance with the requirements of the ASME Code Section III (Appendix XXIII of Section III Appendices). The inspector also confirmed that the replacement RVCH and CRDM housings were provided as Code NPT stamped components.

The records reviewed by the inspector are identified in the Attachment to this report.

b. Findings

No findings of significance were identified.

.6 Head Assembly Upgrade Package (HAUP) (71007)

During the Spring 2005 refueling outage, the licensee elected to install a reactor HAUP that integrated the design of various plant components and structures into the reactor head assembly. This integration involved the reuse of some plant components and the complete replacement of others including:

- CRDM cooling internal ducts;
- new integral reactor vessel missile shield;
- reactor vessel head lift rig;
- CRDM/rod position indication cable drawbridge;
- handrail modifications and new ladders;
- new integral radiation shielding; and
- reactor vessel head insulation.

a. Inspection Scope

From June 1, 2005, through July 1, 2005, the inspector reviewed the licensee's design documentation associated with the installation of the HAUP. Specifically, the inspector reviewed the design specification and a representative sample of design calculations to confirm that HAUP structures and components were designed in accordance with the requirements of the HAUP design specification and the American Institute of Steel Construction (AISC) and ASME design codes.

The records reviewed by the inspector are identified in the Attachment to this report.

b. Findings

.1 Non-conservative Methodology and Assumptions Used in Design Calculations

Introduction: The inspector identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," with very low safety significance (Green). The licensee failed to apply design control measures to verify the adequacy of the design calculations that provided the basis to ensure the safety injection (SI) system would be capable of injecting water into the reactor vessel to remove decay heat following a postulated reactor vessel closure head RVCH drop onto the reactor vessel flange. Specifically, non-conservative assumptions and a non-conservative design methodology were used without justification and the calculations did not include all of the structural components that would be affected by a reactor vessel head drop in the design evaluations that provided the basis for the maximum lift elevation allowed for the reactor vessel head removal and replacement during refueling operations.

Description: The inspector reviewed calculation CN-RVHP-04-83, Revision 1, "Prairie Island Reactor Head Drop Analysis: Maximum Allowable Reactor Head Weight," that was performed due to the weight increase of the combined replacement RVCH and HAUP. This calculation concluded that an accidental reactor head drop over irradiated fuel in an open reactor vessel will not adversely affect the functionality of the SI system if the reactor head weight does not exceed 195,351 pounds for a maximum lift that does not exceed the 765 foot elevation.

Calculation CN-RVHP-04-83 used the methodology, design requirements, and acceptance limits developed in calculation PI-S-014, Revision 0, "Reactor Head Drop Study," for the original RVCH weight and included calculation PI-S-014 as an appendix. Calculation PI-S-014 provided the basis for the maximum allowed lift elevation, 765 feet, over irradiated fuel in an open reactor vessel for the original RVCH that was controlled in maintenance procedures D58.1.9, Revision 10, "Unit 1 - Reactor Vessel Head Removal," and D58.2.9, Revision 10, "Unit 2 - Reactor Vessel Head Removal," and documented in the USAR, Revision 25, Section 12.2.12.1.4, "Containment Polar Crane Evaluation."

As indicated above, calculation CN-RVHP-04-83 utilized the methodology and acceptance limits from calculation PI-S-014 to determine an allowable reactor vessel head lift of 195,351 pounds. The limiting acceptance criteria were:

- $\mu = 20$ — maximum ductility ratio in the box support vertical steel plates to prevent premature buckling and thereby ensure structural stability of the box support

- $\Delta_{total} = 0.55"$ — maximum downward vertical deflection of the reactor vessel to ensure capability of the SI system to inject water into the reactor vessel to remove decay heat

The inspector reviewed calculation PI-S-014 and identified the following non-conservative or unjustified assumptions related to the evaluation methodology and acceptance criteria:

- The evaluation utilized the principle of "conservation of momentum" to evaluate the effects of the reactor vessel head impact onto the reactor vessel flange. The evaluation methodology postulated that due to a "plastic" collision, the reactor vessel head and reactor vessel will move in unison at the same velocity following impact. Due to the large mass of the reactor vessel (target) when compared to the reactor vessel head (missile), only a small portion of the total impact energy, 17 percent, was resolved into the reactor vessel supporting structural components.

The inspector reviewed calculation references that developed the methodology based on conservation of momentum. The calculation methodology assumed an idealized plastic collision without providing further justification. The inspector concluded that an idealized plastic collision between the reactor vessel head and the reactor vessel flange was non-conservative based on the physical dimensions of these structures; i.e., the reactor vessel head would not likely move in unison with the reactor vessel immediately following impact.

- The inspector noted that the calculation did not establish that the principle of "conservation of energy" was preserved. During discussions with the licensee's contractor that prepared the calculation, the inspector determined that it was assumed that the remaining impact energy, 83 percent, would be dissipated into the missile and target as heat generated at the impact boundary and plastic deformation of these structures. The inspector concluded that the assumption regrading the magnitude of the impact energy dissipated into the reactor vessel structural components was non-conservative and needed to be justified since it was based of an idealized plastic collision between the reactor vessel head and the reactor vessel flange.

- The inspector noted a calculation acceptance criterion for the allowable ductility ratio, $\mu = 20$, for the box support vertical steel plates. The calculation referenced Section 3.5.3, "Barrier Design Procedures," of NUREG-0800 where a ductility ratio of only 1.3 was indicated to be appropriate for compression members. The inspector concluded that the use of a ductility ratio equal 20 for structures in compression without providing further justification was a non-conservative assumption.

- The inspector further noted that the calculation did not evaluate all of the structural components that would be affected by a reactor vessel head drop. The inspector concluded that to postulate that these structures would remain intact following a reactor vessel head drop was a non-conservative assumption that needed to be justified.

The licensee entered this issue into their corrective action program as CAP 042052 and CAP 042117. To confirm the applicability of the methodology and unjustified assumptions utilized in calculation PI-S-014, an independent licensee contractor performed a subsequent evaluation of the postulated reactor vessel head drop using non-linear, time-history, finite element analysis methods to model the impact and evaluate the effect of the impact on the reactor vessel supporting components in order to demonstrate that the SI system would remain capable of injecting water into the reactor vessel to remove decay heat. This analysis was documented as calculation 2005-05621, Revision 1, "Analysis of Postulated Reactor Head Load Drop onto Reactor Vessel Flange."

The inspector and technical specialists from the NRC Office of Nuclear Reactor Regulation (NRR) reviewed calculation 2005-05621. To address NRC identified concerns, the licensee's contractor performed additional sensitivity analyses to bound the effects of the uncertainty associated with parameters used in the finite element model and to further demonstrate that the calculation results had adequate margin of safety. Calculation 2005-05621 demonstrated that the reactor vessel components were structurally stable, and therefore, the SI system would remain functional for the following RVCH weight and lift elevation restrictions:

- 200,000 pound maximum total weight for the RVCH lift over the reactor vessel, and
- a maximum lift height of 27 feet above the reactor vessel flange which corresponds to the 756.5 foot elevation that is 27 feet above the top of the reactor vessel flange.

Analysis: The inspector determined that a performance deficiency existed because the owner's acceptance review of their design contractor's supplied calculations CN-RVHP-04-83 and PI-S-014 failed to identify the non-conservative assumptions, the non-conservative analysis methodology, and that the evaluation of the reactor vessel supporting components was incomplete. Furthermore, the inspector determined that it was reasonably within the licensee's control to have identified the calculation concerns and ensured that the appropriate design requirements for a postulated replacement RVCH drop were correctly translated into the design and installation documents.

As a result of the inspector concern that unjustified, non-conservative assumptions and design methodology were used and that all structural components that support the reactor vessel were not evaluated in calculations CN-RVHP-04-83 and PI-S-014, a new independent calculation, 2005-05621, was performed. Comparing the results of the three calculations:

- Calculation PI-S-014 documented that the original RVCH weighing up to 187,000 pounds could be lifted up to 35.5 feet, 765 foot elevation, above the reactor vessel flange.

- Calculation CN-RVHP-04-83, using the same assumptions, methodology and acceptance criteria as calculation PI-S-014, documented that the replacement RVCH with the HAUP weighing up to 195,351 pounds could be lifted up to 35.5 feet, 765 foot elevation, above the reactor vessel flange.

- Calculation, 2005-05621, using finite element methods, showed that the replacement RVCH with the HAUP weighing up to 200,000 pounds could be lifted only 27 feet, 756.5 foot elevation, above the reactor vessel flange.

By further comparing the associated reactor vessel head drop impact energy for each calculation:

- 6,934,960 ft-lb for calculation CN-RVHP-04-83;
- 6,638,500 ft-lb for calculation PI-S-014;
- 5,400,000 ft-lb for calculation 2005-05621; and
- that calculation 2005-05621 lowered the allowable lift elevation to 756.5 feet, the inspector concluded that a non-conservative methodology and assumptions were used in calculations CN-RVHP-04-83 and PI-S-014 to allow a reactor vessel head lift up to the 765 foot elevation over the reactor vessel.

The inspector determined the finding was more than minor because it affected the mitigating systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events and if left uncorrected the finding could become a more significant safety concern. Specifically, the calculational deficiencies resulted in a non-conservative determination of maximum allowable head lift height. The SI system may not have been capable to inject water into the reactor vessel to remove decay heat as designed if the original RVCH or the replacement RVCH with the HAUP was dropped from the 765 foot elevation onto the reactor vessel as allowed in maintenance procedures D58.1.9 and D58.2.9 and as documented in the USAR for the Prairie Island Nuclear Generating Plant (PINGP).

The inspector determined the finding was of very low safety significance (Green) because the polar crane capacity had considerable margin with respect to the original, lighter weight RVCH and the issue was appropriately addressed prior to lifting the heaver replacement RVCH.

Enforcement: Criterion III, "Design Control," of 10 CFR Part 50, Appendix B, requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis, for those systems, structures and components for which this appendix applies, are correctly translated into specifications, drawings, procedures and instructions. It further requires that the design control measures provide for verifying or checking the adequacy of the design.

Contrary to the above, the adequacy of the design was not adequately verified or checked, nor was the appropriate requirement translated into procedures and the USAR in the following instance:

- The inspector identified on April 29, 2005, that calculation CN-RVHP-04-836, Revision 1, approved by electronic signature and date, and calculation PI-S-014, Revision 0, approved on September 24, 1998, used non-conservative assumptions, a non-conservative design methodology, and failed to evaluate all reactor vessel structural support components. The purpose of these calculations was to demonstrate that if the replacement RVCH with the HAUP or the original RVCH were dropped from elevation 765 feet onto the reactor vessel, the SI system would remain capable of injecting water into the reactor vessel to remove decay heat. As a result of further analysis, calculation 2005-05621, Revision 1, approved on May 23, 2005, determined that the replacement

RVCH with the HAUP and the original RVCH needed to be limited to elevation 756.5 feet over the reactor vessel in order to ensure that the SI system would remain capable of injecting water into the reactor vessel to remove decay heat.

Because of the very low safety significance of the issue and because it was entered into the licensee's corrective action program as condition reports CAP 042052 and CAP 042117, this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000306/2005004-06).

.2 Unable to Determine Significance of HAUP Design Concerns

Introduction: The inspector identified a URI concerning the design calculations that demonstrate the design adequacy of the HAUP.

Description: The inspector reviewed a sample of the design documentation that demonstrate the design adequacy of the HAUP. As a result of this review, a number of concerns were identified related to design loads, design methods, numerical errors, and the basis for acceptance criteria that were utilized in the calculations. The inspector identified concerns that include:

- Part 2 of Design Change 03RV05 indicated that Westinghouse NSAL-05-1 documented that loss of coolant accident (LOCA) loads may not have been included in the design basis for some HAUP structural components. The concern was whether HAUP components subject to LOCA loading would remain intact during a LOCA event and not affect nearby safety related structures or components. The licensee's contractor had not completed their evaluations that addressed this issue.

- Several evaluations of structural bolting failed to transform bolt design loads into the bolt analysis coordinate system used for the evaluations. These bolt design loads, when transformed from the bolt design load coordinate system into the bolt analysis coordinate system, will result in additional moment, and hence that additional moment was not analyzed. Calculations affected by this issue include CN-RVHP-04-87, Revision 1 and CN-RVHP-04-90, Revision 1.

- Examples were identified where structural components in compression were evaluated with the theoretical "K" factor instead of the AISC recommended "K" factor to determine the effective buckling length without providing a basis for the less conservative design parameter. Calculations affected by this issue include CN-RVHP-04-87, Revision 1, and CN-RVHP-04-90, Revision 1.

- In calculation CN-RVHP-04-87, Revision 1, thin-walled cooling duct should have been classified as a "non-compact" section in accordance with AISC Table B5.1. The non-conservative allowable stress used in the calculation was for an AISC "compact" section.

In addition, in calculation CN-RVHP-04-90, Revision 1, thin-walled cooling duct should have been classified as a “slender compression element” in accordance with the AISC Table B5.1 and evaluated in accordance with AISC Appendix B5 rules.

- Calculation CN-RVHP-04-87, Revision 1 appeared to contain errors in the mathematical computations that calculated the combined interaction ratio, IR_C Eq-5, in Tables 6.3.4-14, 6.3.4-15, 6.3.4-16, 6.3.4-23, and 6.3.4-24.

- Calculation CN-RVHP-04-128, Revision 1 used an effective acceptance criterion of 0.78 Fcr, where Fcr is the theoretical critical buckling stress, for compression components by specifying 1.5 times the AISC design allowable. In addition, this calculation set the upper limit for compression components to be 0.90 Fcr. The inspector requested the licensee’s basis for these calculation acceptance limits given that ASME Section III Appendix F-1331.5 limits compression to (2/3) Fcr and the corresponding AISC limit for seismic applications would be (4/3) times the design allowable or approximately (2/3) Fcr.

This item is being held as a URI pending evaluation of these concerns by the licensee and subsequent inspector review and discussion with the licensee. The licensee entered these issues into their corrective action system as condition report CAP 043325 (URI 05000306/2005004-07).

.3 Closure of Unresolved Item

(Closed) URI 05000282/2000013-06; 05000306/2000013-06: Unable to Determine the Validity of the Practice of, after a Seismic Event, Using Assumptions for Through Wall Leakage Rather Than Complete Pipe Severance.

By memorandum dated March 27, 2001, NRC Region III requested assistance from the NRR in resolving this URI under the Task Interface Agreement (TIA) process, and the issue was designated as TIA 2001-02. By memorandum dated August 29, 2002, the NRR staff’s responses to the issues identified in TIA 2001-02 were provided to Region III.

On May 3, 2004, as supplemented by letters dated February 4 and March 28, 2005, the Nuclear Management Company (NMC), LLC submitted a license amendment request PINGP Units 1 and 2, to address the issues contained in NRR’s response to TIA 2001-02.

On May 10, 2005, NRR issued Amendment No. 169 to Facility Operating License No. DPR-42 and Amendment No. 159 to Facility Operating License No. DPR-60 for the PINGP, Units 1 and 2 respectively. The amendments consist of changes to the TS in response to the PINGP application dated May 3, 2004, as supplemented by letters dated February 4 and March 28, 2005. No violations were identified. This item is closed.

4OA6 Meeting(s)

.1 Exit Meeting

The inspectors presented the inspection results to Mr. T. Palmisano and other members of licensee management at the conclusion of the inspection on July 12, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Procedure 7111108, and Section 02.05.e of Procedure 71007 with Mr. L. Clewett, and other members of licensee management at the conclusion of the inspection on May 19, 2005. The inspectors returned proprietary information reviewed during the inspection and the licensee confirmed that none of the potential report input discussed was considered proprietary.

- Occupational Radiation Safety inspection with Mr. R. Graham, Site Director of Operations on May 13, 2005.

- Inspection of the modifications associated with the replacement reactor vessel closure head (IP 71007) were discussed with Mr. J. Solymossy, Site Vice President, and other members of the licensee's staff on July 6, 2005. The licensee confirmed that the design documentation prepared by their contractors was considered proprietary. It was agreed that copies of all proprietary documentation would be returned to the licensee.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

J. Anderson, Radiation Protection and Chemistry Manager
J. Callahan, Emergency Planning Manager
L. Clewett, Plant Manager
R. Graham, Director of Site Operations
P. Huffman, Operations Manager
J. Kivi, Licensing Engineer
C. Koehler, Reactor Head Replacement Project Manager
J. Lash, Training Manager
K. Ludwig, Maintenance Manager
J. Maki, Outage and Scheduling Manager
S. McCall, Manager of Engineering Programs
C. Mundt, Engineering Plant and Systems Manager
S. Northard, Bussiness Support Manager
T. Palmisano, Site Vice President (incoming)
G. Park, Fleet ISI Supervisor
E. Perry, NOS Supervisor
A. Qualantone, Security Manager
G. Salamon, Regulatory Affairs Manager
T. Silverberg, Site Engineering Director
J. Solymossy, Site Vice President (outgoing)
S. Thomas, Engineering Supervisor
C. Tomes, Fleet Lead NMC Engineer Head Replacement
J. Wren, NDE Level III

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000282/2005-001-00	LER	Discovery of Single Failure Vulnerability of Unit 1 Safeguards Buses (Section 4OA3)
05000282/2005004-01; 05000306/2005004-01	FIN	Failure to Identify and Remove/Secure Potential Tornado Missile Hazards (Section 1RO1.1)
05000306/2005004-02	NCV	Inadequate Control of Transient Combustibles (Section 1RO5.1)
05000282/2005004-03; 05000306/2005004-03	URI	Configuration Control Event Causes a Loss of Automatic Fire Suppression to the Relay Room (Section 1RO5.3)

05000282/2005004-04; 05000306/2005004-04	NCV	Inadequate Ultrasonic Examination Procedure for the Reactor Vessel Flange-to-Shell Weld (Section 1RO8)
05000282/2005004-05	URI	Inadequate Design Control Causes Single Failure Vulnerability on Buses 15 and 16 (Section 4OA3)
05000306/2005004-06	NCV	Non-conservative Methodology and Assumptions Used in Design Calculations (Section 4OA5.6.b.1)
05000306/2005004-07	URI	Unable to Determine Significance of HAUP Design Concerns (Section 4OA5.6.b.2)

Closed

05000282/2005-001-00	LER	Discovery of Single Failure Vulnerability of Unit 1 Safeguards Buses (Section 4OA3)
05000282/2005004-01; 05000306/2005004-01	FIN	Failure to Identify and Remove/Secure Potential Tornado Missile Hazards (Section 1RO1.1)
05000306/2005004-02	NCV	Inadequate Control of Transient Combustibles (Section 1RO5.1)
05000282/2005004-04; 05000306/2005004-04	NCV	Inadequate Ultrasonic Examination Procedure for the Reactor Vessel Flange-To-Shell Weld (Section 1RO8)
05000306/2005004-06	NCV	Non-conservative Methodology and Assumptions Used in Design Calculations (Section 4OA5.6.b.1)
05000282/2000013-06; 05000306/2000013-06	URI	Unable to Determine the Validity of the Practice of, after a Seismic Event, Using Assumptions for Through Wall Leakage Rather Than Complete Pipe Severance (Section 4OA5.6.b.3)

Discussed:

None.

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

C37.8; Screenhouse Safeguards Equipment Cooling; Revision 8

C37.8-1; Screenhouse Safeguards Ventilation System; Revision 5W

TP 1636; Summer Plant Operation; Revision 19

CAP 040941; Unrestricted Condensate Pump Configuration Challenged During Summer Operations

CAP 037382; DDCLP Heat Exchanger Preventative Maintenance Did Not Contain As-Found Acceptance Criteria

CAP 041237; Busted Piping on Glycol Roof Coolers

CAP 032283; 13 Condensate Pump Motor Stator Hi Temperature

CAP 030821; Work Order 13 CD Pump Stator High Temperatures Closed Without Adequate Followup

1R02 Evaluation of Changes, Tests, or Experiments (71111.02)

Design Change 03RV05 Part 1; Replace Unit 1 and 2 Reactor Vessel Heads and Associated Components; Revision 0

Design Change 03RV05 Part 2; Reactor Vessel Head Assembly Upgrade Package (HAUP); Revision 0

10 CFR 50.59 Evaluation No. 1040; Design Change 03RV05 Part 1; Square Root Sum of the Squares Load Combination; Revision 0

10 CFR 50.59 Evaluation No. 1042; Design Change 03RV05 Part 2; RV Missile Shield Replacement; Revision 0

10 CFR 50.59 Screening No. 2120; Design Change 03RV05 Part 1, Documents Related to the Reactor Vessel Head, Penetrations, and Spare Penetration Caps; Revision 0

10 CFR 50.59 Screening No. 2121; Design Change 03RV05 Part 1, Documents Related to Full Length CRDM Pressure Housing and Internals; Revision 0

10 CFR 50.59 Screening No. 2122; Design Change 03RV05 Part 1, Documents Related to Thermocouple Penetration Adapter Upgrades, Core Exit Thermocouple Nozzle Assemblies; Revision 0

10 CFR 50.59 Screening No. 2123; Design Change 03RV05 Part 1, Documents Related to RCGVS and RVLIS Pipe and Supports; Revision 0

10 CFR 50.59 Screening No. 2125; Design Change 03RV05 Part 2, HAUP Documents Related to the Reactor Vessel CRDM Seismic Platform, Seismic Spacer Plate, Adjustment Plate Assembly, Cable Supports; Revision 0

10 CFR 50.59 Screening No. 2126; Design Change 03RV05 Part 2, HAUP Documents Related to Thermocouple and CRDM Coil Bridge, Rod Position Indication and CRDM Drawbridge, Messenger Lines; Revision 0

10 CFR 50.59 Screening No. 2127; Design Change 03RV05 Part 2, HAUP Documents Related to CRDM Cooling: Coils, Fans, Pipe/Pipe Supports and Instrumentation and Control; Revision 0

10 CFR 50.59 Screening No. 2128; Design Change 03RV05 Part 2, HAUP Documents Related to Reactor Vessel CRDM Shroud, Support Ring, Access Doors, and Radiation Shield; Revision 0

1R05 Fire Protection

Plant Safety Procedure F5, Appendix A, Revision 15; Fire Strategies for Fire Areas; 20, 102, 114, 118, 128, 72, and 71 .

Plant Safety Procedure F5, Appendix F, Revision 19; Fire Hazard Analysis for Fire Areas; 20, 102, 114, 118, 128, 72, and 71.

IPEEE NSPLMI-96001, Appendix B; Internal Fires Analysis; Revision 2

Administrative Work Instruction 5AWI 3.13.2, Fire Prevention Practices

CAP 042539; Transient Combustibles Inside of Containment During 2R23

1R06 Flood Protection Measures (Internal)

5 AWI 8.9.0; Internal Flooding Drainage Control; Revision 2

Design Basis Document (DBD) Top-05; Hazards; Revision 2W

CAP 042319; Floor Drain Appears Partially Plugged in AFW Pump Room (695' Turbine Building)

1R08 Inservice Inspection Activities

CAP 039932; as Left Condition of the Reactor Head after Cleaning Boric Acid from Conoseal Leakage; dated November 20, 2004

CAP 037863; 1R23 Leakage from Instrument Port Conoseals; dated November 6, 2004

OPR 000453 (CAP 032754); Boric Acid Leak at Valve 2RH-10-1; dated September 20, 2003

OPR 000454 (CAP 032755); Boric Acid Leak at Valve 2RH-1-1; dated September 20, 2003

OE 035584; TB-04-19 SG Channel Head Bowl Drain Line Leakage; dated November 1, 2004

OE 19662; SGs at Catawba; dated January 1, 2004

CAP 033128; Trending Small Objects Found in No. 22 SG Tubesheet; dated September 30, 2003

CAP 033116; 2R22 Outage SG ISI Repairs - Installed Incorrect Reroll in Repairable Tube; dated September 30, 2003

CA 007361; Diablo Canyon Inspection Justification and Findings; dated October 10, 2003

Corrective Action Program Documents As a Result of NRC Inspection

CAP 042091; Calibration Block Does Not Meet ASME Code Section V, Article 4; dated May 2, 2004

CAP 042491; ASME Section XI IWA-2240 Demonstration Documentation; dated May 17, 2005

CAP 042493; Review and Revise VT-2 Pressure Test; dated May 17, 2005

Documents Related to Code Pressure Boundary Brazing

WO 0503331; Repair Leak on No. 23 Containment Fan Cooler Unit Face; dated March 30, 2005

WO 0501441; Repair Leak on No. 23 Containment Fan Cooler Unit Face; dated March 28, 2005

FP-PE-31-P107P107-BR-065; Lap/Socket P107 Torch Brazing Copper/Copper; Revision 0 and Revision 1

NMC-PQR-ASME-266; Revision 0

NMC-PQR-ASME-267; Revision 0

NMC-PQR-ASME-268; Revision 0

20050304; Prairie Island Weld Control Record; dated March 28, 2005

Documents Associated with ASME Code Nondestructive Testing

UT Calibration Data Sheet No. SI-STAR-TAN-1; dated May 9, 2005

UT Calibration Data Sheet No. SI-STAR-TAN-2; dated May 9, 2005

UT Calibration Data Sheet No. SI-STAR-TAN-3; dated May 9, 2005

UT Calibration Data Sheet No. SI-STAR-TAN-4; dated May 9, 2005

UT Calibration Data Sheet No. SI-STAR-TAN-5; dated May 9, 2005

UT Calibration Data Sheet No. SI-STAR-TAN-6; dated May 9, 2005

UT Calibration Data Sheet No. S-1; dated May 9, 2005

UT Calibration Data Sheet No. S-2; dated May 9, 2005

UT Calibration Data Sheet No. S-3; dated May 9, 2005

UT Calibration Data Sheet No. S-4; dated May 9, 2005

UT Calibration Data Sheet No. S-5; dated May 9, 2005

UT Calibration Data Sheet No. S-6; dated May 9, 2005

UT Calibration Data Sheet No. US-1; dated May 9, 2005

UT Calibration Data Sheet No. US-2; dated May 9, 2005

UT Calibration Data Sheet No. US-3; dated May 9, 2005

UT Calibration Data Sheet No. US-4; dated May 9, 2005

UT Calibration Data Sheet No. US-5; dated May 9, 2005

UT Calibration Data Sheet No. US-6; dated May 9, 2005

UT Calibration Data Sheet No. US-7; dated May 9, 2005

UT Calibration Data Sheet No. US-8; dated May 9, 2005

W-1 Reactor Vessel Weld Results Summary, Shell to Flange Weld; dated May 15, 2005

W-2 Reactor Vessel Weld Results Summary, Upper Shell Weld; dated May 15, 2005

–7 Reactor Vessel Weld Results Summary, Outlet Nozzle to Shell at 28.5 Degrees; dated May 15, 2005

–10 Reactor Vessel Weld Results Summary, Outlet Nozzle to Shell at 208.5 Degrees; dated May 15, 2005

–8 Reactor Vessel Weld Results Summary, Safety Injection Nozzle to Shell at 108.5 Degrees; dated May 15, 2005

Documents Associated with Disposition of Relevant Indications

Report 2003V004; CWH-26 Sway Strut; dated September 19, 2003

CAP 032895; 2CWH-26 Misaligned; dated September 23, 2003

Report 2003V127; CWH-29 Sway Strut; dated September 24, 2003

CAP 032975; Indications Found on 2CWH-29; dated September 25, 2003

Report 2005V065; H-4 RC Support; dated May 15, 2005

CAP 042441; Loose U-Bolt and Nuts on Support 137-2RTD-3; dated May 16, 2005

Other Documents

WDI-SSP-082; Manual Ultrasonic Examination of the Reactor Vessel Upper Shell to Flange Weld for Prairie Island; Revision 1

PDI-ISI-254; Remote Inservice Examination of Reactor Vessel Shell Welds; Revision 7

PDI-ISI-254-SE; Remote Inservice Examination of Reactor Vessel Nozzle to Safe End, Nozzle to Pipe, and Safe End to Pipe Welds; Revision 1

SWI NDE-VT-2.0; Visual Examination of Components and Their Supports; Revision 0 (TCN 2005-0138)

SWI NDE-VT-1.0; Visual Examination; Revision 0 (TCN 2005-0139)

H2; Boric Acid Corrosion Control Program; Revision 6

Year 2005 Reactor Vessel Examination Program Plan; dated May 7, 2005

FA-P12-021; Condition Monitoring and Operational Assessment of Degraded Steam Generator Tubing at Prairie Island; dated September 2003

H25.1; Assessment of SG Tube Degradation Mechanisms; Revision 1

H25.2; Unit 2 Steam Generator Condition Monitoring; Revision 0

ETSS 96005.2; Revision 8

ETSS 20511.1; Revision 7

ETSS 21409.1; Revision 4

ETSS 96007.1; Revision 10

ETSS 965111.2; Revision 14

EPRI, PDQS No. 407; dated October 26, 2001

EPRI, PDQS No. 434; dated January 13, 2003

EPRI, PDQS No. 453; dated December 4, 2003

EPRI, PDQS No. 471; dated October 11, 2003

EPRI, PDQS No. 470; dated September 20, 2004

2005V067; Visual Examination of Component Supports and Snubbers (VT-3) Support RC, H-1; dated May 15, 2005

2005V068; Visual Examination of Component Supports and Snubbers (VT-3) Support RC, H-1; dated May 15, 2005

2005V066; Visual Examination of Pressure Retaining Bolting (VT-1) Support RC Valve Bolting, B-1; dated May 15, 2005

2005V074; Visual Examination of Welds (VT-1) Integral Attachment AF, H-1/1A; dated May 15, 2005

2005V073; Visual Examination of Component Supports and Snubbers (VT-3) Support AF, H-2; dated May 15, 2005

2005V072; Visual Examination of Component Supports and Snubbers (VT-3) Support AF, H-1; dated May 15, 2005

2005V065; Visual Examination of Component Supports and Snubbers (VT-3) Support RC, H-4; dated May 15, 2005

5AWI 14.6.0; ASME Section XI Inservice Inspection and Pressure Testing; Revision 5

1R11 Licensed Operator Requalification Program

P9160-001, Attachment SQ 49

1R13 Maintenance Risk Assessments and Emergent Work Control

D5, 22 Charging Pump, and Valve 2VC-21-13
Unit 2 Configuration Risk Assessment for April 11, 2005

Operator Logs for April 11, 2005

Unit 2 Intake Bay, Bus 16/26 Load Sequencers, and D2

Unit 1 Configuration Risk Assessment for May 9, 2005

Operator Logs for May 9, 2005

Unit 2 Intake Bay and Loop B Cooling Water Header

Unit 1 Configuration Risk Assessment for May 16, 2005

Operator Logs for May 16, 2005

CAP 042488; Unit 1 Probabilistic Risk Assessment Core Damage Probability Calculation Error for 5/16/05 - 5/17/05 (NRC Identified)

Emergent Failure of Cooling Water Valve CL-19-6

Phase 2 At-Power Risk Report; dated May 21, 2005

CAP 042598; Unit 1 Equipment Failure Causes Probabilistic Risk Assessment Orange Category

A Cooling Water Header and Blue Lake Line

Unit 1 Configuration Risk Assessment for June 14, 2005

Emergent Severe Thunderstorms

Unit 1 and 2 Configuration Risk Assessment for June 20, 2005

1R14 Nonroutine Evolutions

Operating Procedure 2C1.3; Unit 2 Shutdown; Revision 53

Operating Procedure 2C14; Component Cooling System - Unit 2; Revision 24

Operating Procedure 2C15; Residual Heat Removal System Unit 2; Revision 32

CAP 042012; Unit 2 Sump B Motor Operated Valves Leaking

1R15 Operability Evaluations

OPR 545 - D6 Diesel Generator

OPR 000545; D6 Diesel Generator Common Mode Failure Susceptibility to Problems Identified on D5 Diesel Generator

OPR 546 - Head Drop Analysis

OPR 000546; Lift of Heavy Loads Over the Reactor Vessel; Revision 0

OPR 000546; Lift of Heavy Loads Over the Reactor Vessel; Revision 1

Reactor Coolant Loop Bypass Orifice Installation Error

CAP 042996; Received 47512-0503 Reactor Coolant Resistance Temperature Bypass Loop Low Flow

1R16 OWAs

Quarterly OWA Sample
CAP 041942; Evaluated D5/D6 Crankcase Manometer Design as Operator Workaround

Cumulative Effect

Prairie Island Operator Workaround List as Updated on April 7, 2005

1R17 Permanent Plant Modifications

50.59 Evaluation #1047; Changes to Primary Chemistry Program Lithium and Hydrogen Limits

1R19 Post-Maintenance Testing

D5 Diesel Generator

SP 2093; D5 Diesel Generator Monthly Slow Start Test; Revision 76

CAP 037095; D5 and D6 Lubricating Oil Shell Rotella T 15W-40 Engine Oil Has Changing Total Base Number

23 Containment Fan Coil Unit

Maintenance Operating Procedure 2M-ZC-274-013; 23 FCU Isolation and Restoration; Revision 0

CAP 042510; Incorrect Quality Assurance Type Specified for FCU Piping on Cooling Water System Drawings

D6 Diesel Generator

SP 2306; D6 Diesel Generator Monthly Slow Start Test; Revision 24

CAP 042430; D6 Diesel Generator Failure to Start During Performance of SP 2305

22 Safety Injection Pump

SP 2088B; Train B Safety Injection Pump Quarterly Test; Revision 8

Solenoid Valve 37465

WO 0504943; Test SV-37465 for PMT of WO 0504531

CAP 042142; During SP 2083 Train B Fan Coil Units did not Swap Over to Cooling Water on S Signal

22 Residual Heat Removal Pump

SP 2089B; Train B Residual Heat Removal Pumps; Revision 6

CAP 034618; 21 Residual Heat Removal Pump Seal Leak

Main Steam Isolation Valve

SP 2406; Main Steam Isolation Valve Inservice Test; Revision 1

CAP 042843; SP 2099 Acceptance Criteria Not Met

1R20 Refueling and Other Outage Activities

Operating Procedure 2C1.2; Unit 2 Startup Procedure; Revision 32

CAP 041619; CBA Group 2 Moved Prior to Group 1

Maintenance Procedure D30; Post Refueling Start Up Testing; Revision 40

1R22 Surveillance Testing

SP 1307; D2 Diesel Generator 6 Month Fast Start Test; Revision 29

SP 2295, D5 Diesel Generator 6 Month Fast Start Test ; Revision 28

SP 2407; Leakage Examination of Canopy Seals, Mechanical Joints, and Other Pressure Retaining Components on the Reactor Vessel Head; Revision 0

SP 2405; Mid-Cycle and Refueling Outage Boric Acid Corrosion Examinations Inside Containment; Revision 0

SP 2083; Unit 2 Integrated Safety Injection Test With a Simulated Loss of Offsite Power; Revision 27

SP 2177; Core Inventory Verification; Revision 11

SP 2072.29A; Local Leak Rate Test of Penetration (29A) Containment Spray; Revision 22

SP 2070; Reactor Coolant System Integrity Test; Revision 34

SP2750; Post-Outage Containment Close-Out Inspection; Revision 28

1R23 Temporary Modifications

04T175 Pressurizer PORV Air Accumulator Supplementation

ENG-ME-592; Determine the Minimum Amount of Air Pressure to Fully Stroke Pressurizer PORV; Revision 0

ENG-ME-584; Sizing of Supplemental Air for Pressurizer PORV Air Accumulators; Revision 0

CAP 039937; Train B Pressurizer PORV Dual Indication during Surveillance Procedure

CAP 039539; Westinghouse Analysis Reveals Higher Required Number of PORV Strokes for Low Temperature Overpressure Protection

NSP-04-189; Data on Pressurizer PORV Cycling During Cold Overpressure Mitigation System (COMS) Transients - New Analysis

CAP 041838; Unplanned U2 LCO Due to Low Temperature Overpressure Protection Supplemental Air Pressure Low

Apparent Cause Evaluation 008946; Unplanned U2 LCO Due to Low Temperature Overpressure Protection Supplemental Air Pressure Low

CAP 041852; Found CV-31233 Pressurizer PORV B Accumulator Supplementation Air Regulator Pressure Outlet at 96 psig

1EP6 Drill Evaluation

CAP 043219; Failure of ERO B-1 Table Staffing During Augmentation Test

2OS1 Access Controls for Radiologically Significant Areas

Radiation Protection Annual Self-Assessment; dated February 1, 2005

Radiation Protection Manager Expectations; Revision 1; dated January 1, 2005

CAP 038965; Poor Radiological Work Practices During Work Around Unit One RHR Pits; dated October 1, 2004

CAP 039702; Radiation Protection Self-Assessment of Outage Performance for Dose, Contamination Control, High Radiation Area/Locked High Radiation Area Controls and Radiation Worker Practices; dated November 5, 2005

CAP 038939; Electronic Dosimeter Found in Rack by NRC Still Logged-on to a Carpenter; dated September 30, 2004

CAP 038854; Worker Entered RHR Pit High Radiation Area on Wrong RWP and Received Dose Alarm; dated September 27, 2004

CAP 039121; Worker Did Not Report Dose Rate Alarms to Radiation Protection; dated October 8, 2004

CAP 040895; Dose Discrepancies Noted for July 1, 2004 to December 31, 2004, TLD Monitoring Period; dated February 8, 2004

CAP 401168; Contaminated Area Barrier Rope Missing from Boundary; dated March 1, 2005

CAP 041564; Unit 2 Fuel Defect Identified; dated March 30, 2005

CAP 041670; TLD Processor Shipped TLDs with Inadequate Shipping Control TLDs; dated April 6, 2005

CAP 042236; High Radiation Area Posting Violation Due to Protected Equipment Signs Placed Over Them; dated May 9, 2005

CAP 042252; Worker Has Dose Rate Alarm and Fails to Exit RCA and Inform Radiation Protection; dated May 9, 2005

CAP 042289; Workers Crossed Steam Generator Eddy Current Step-off-pad Without Proper Suit-up Requirements; dated May 10, 2005

CAP 042316; 2R23 Worker Contamination; dated May 11, 2005

CAP 042322; Worker Entered High Radiation Area Under Wrong RWP; dated May 12, 2005

RWP 2162; Old Reactor Vessel Head - Disassemble and Package on Head Stand and Move to the Equipment Hatch; Revision 1

RWP 2163; Rig and Move Old Reactor Vessel Head to Bigger Trailer; Revision 1

2OS2 ALARA Planning and Controls

Site ALARA Committee Meeting Minutes; dated October 25, 2004

RCS Cutting and Welding Activities ALARA Plan; dated April 7, 2004

Reactor Head Replacement Project ALARA Plan; Revision 1

CAP 039890; Pipe End Decon is at 190 Percent of the Dose Estimate; dated October 2, 2004

CAP 039196; Document Station ALARA Committee Activity for RWP Extension Requests; dated October 11, 2004

CAP 039412; RWP 1420 Steam Generator Replacement Project RCS Cutting and Welding is Significantly Over Dose Goal; dated October 21, 2004

CAP 039640; Adverse Trend in Dose Goal Estimation; dated November 2, 2005

CAP 039906; Control of In-Core Instrumentation Should be Evaluated During Outages; dated November 18, 2005

CAP 040276; Review of Dose Trends Indicate Increased General Area Dose Rates; dated December 17, 2004

CAP 040284; Adverse Trend - Inaccurate Dose Estimation and Reporting; dated December 18, 2005

CAP 042111; Shielding Installed on 2SI-6-3 in Excess of Permitted Amount; dated May 3, 2005

CAP 042127; Control of Air Flow in Containment/Annulus Was Not Maintained Negative; dated May 4, 2005

CAP 041703; Findings of ALARA Self-Assessment; dated April 7, 2005

CAP 042262; Seal Table Procedure Difficulty Contributes to Poor ALARA Practices; dated May 9, 2005

CE 006397; RWP 41410 Steam Generator Replacement RCS Cutting and Welding is Significantly Over Dose Goal; dated October 22, 2004

2PS2 Radioactive Material Processing and Transportation

Shipment No. 05-032; Reactor Pressure Vessel Head Transportation Package; dated May 26, 2005

ER-04-009; Characterization of the Prairie Island Unit-2 Reactor Pressure Vessel Head; dated October 12, 2004

4OA2 Identification and Resolution of Problems

Annual Sample - Correction of a Potential Inadvertent Dilutions Pathway

CAP 030429; Boric Acid Transfer Pump Restoration Procedures Could Result In an Inadvertent Dilution

Operating Procedure C12.6; Boric Acid Transfer Pump and Storage Tank; Revision 17

Maintenance Operating Procedure 1M-VC-145-612; 12 Boric Acid Transfer Pump Isolation and Restoration; Revision 2

Maintenance Operating Procedure 1M-VC-145-611; 11 Boric Acid Transfer Pump Isolation and Restoration; Revision 1

Maintenance Operating Procedure 2M-VC-245-031; 21 Boric Acid Transfer Pump Isolation and Restoration; Revision 2

Maintenance Operating Procedure 2M-VC-245-032; 22 Boric Acid Transfer Pump Isolation and Restoration; Revision 1

Maintenance Procedure D48; Boric Acid Pump Seal Replacement; Revision 21

Drawing X-HIAW-1-41; Chemical and Volume Control System Unit 1 and 2; Revision V

4OA3 Event Followup

CAP 040867; Single Failure Identified That Could Prevent Reenergizing Both 4KV Safeguards Buses

4OA5 Other Activities

4OA5.1 Reactor Vessel Head Replacement Inspection (IP 71007)

Corrective Action Program Documents As a Result of NRC Inspection

CAP 042483; Unit 2 Replacement Reactor Head Bimetallic Weld Dye Penetrant Exams; dated May 17, 2005

Westinghouse Letter NSP-05-137; NRC Question 59 on Prairie Island Unit 2 Preservice Inspection; dated May 3, 2005

Liquid Penetrant Examination Records

No. 3201-RVH-10E-RO-56; Latch Housing and Rod Travel Housing; dated November 3, 2004

No. 3201-RVH-10E-RO-58; Closure Cap and Spare CRDM Head Adapter; dated November 3, 2004

No. 3201-RVH-60B01-RO-26; Instrument Port Head Adapter Flange and Head Adapter; dated June 19, 2004

No. 3201-RVH-60B01-RO-40; Instrument Port Head Adapter Flange and Head Adapter; dated June 30, 2004

No. 3201-RVH-60B01-RO-41-1; Instrument Port Head Adapter Flange and Head Adapter; dated July 1, 2004

No. 3211-RVH-40B01-RO-31-1; One Piece Latch; January 29, 2004

Other Documents

UGS-L5-030244; PT Procedure (Solvent Removable); Revision 2

UGS-L5-040157; PT Procedure (Solvent Removable) for PSI; Revision 3

UGS-L5-040158; Procedure for the Manual UT Examination of Similar and Dissimilar Metal Welds Located in the NMC Top Head Rod Drive Housing; Revision 3

CN-RCOA-04-100; Nuclear Management Company Prairie Island Unit 2 RRVCH ASME Section XI Code Reconciliation; Revision 0

Appendix F of Design Report PI-KCS-04-000; Prairie Island CRDM - ASME Code Section XI Reconciliation; dated January 20, 2005

L5-03BM009; Control Rod Drive Mechanism Pressure Housing Welding Drawing; Revision 5

Design Specification 418A07; Replacement Reactor Vessel Closure Head; dated October 1, 2004

Design Specification 418A08; Control Rod Drive Mechanism Model L106A; dated October 14, 2004

WDI-PJF-1303030-FSR-001; Replacement Reactor Vessel Closure Head Pre-service Inspection Final Report Summary; dated December 2004

WesDyne International Surface Examination Data Sheets

RRVCH Full Length CRDM 4" Full Penetration Dissimilar Metal Weld No. WC-M202-1A; dated December 8, 2004

RRVCH Full Length CRDM 4" Full Penetration Dissimilar Metal Weld Nos. WC-M202-10A - 33A; dated December 8, 2004

RRVCH Full Length CRDM 4" Full Penetration Dissimilar Metal Weld Nos. WC-M202-38A - 41A; dated December 8, 2004

RRVCH Spare CRDM 4" Full Penetration Stainless Steel Weld Nos. WC-R116-2A - 5A; dated December 8, 2004

RRVCH Spare CRDM 4" Full Penetration Dissimilar Metal Weld Nos. WC-R114-2A - 5A; dated December 8, 2004

Instrumentation Port had Adapter 4" Dissimilar Metal Weld Nos. WC-R110-34A, 35A and 37A; dated December 9, 2004

RRVCH Full Length CRDM 7.385 Full Penetration Weld Nos. WC-M009-1A, 10A-33A, 38A-41A; dated December 5, 2004

RRVCH Full Length CRDM J-Groove Weld Nos. WC-R109-1A, 10A-33A, 38A-41A; dated December 5, 2004

RRVCH Full Length CRDM J-Groove Weld Nos. WC-R109-1A and 27A; dated December 8, 2004

WesDyne International Ultrasonic Calibration Data Sheets

Latch Housing to Head Adaptor 4" Dissimilar Metal Weld No. WC-M202-1A; dated December 11, 2004

Latch Housing to Head Adaptor 4" Dissimilar Metal Weld Nos. WC-M202-10A-33A; dated December 11, 2004

Latch Housing to Head Adaptor 4" Dissimilar Metal Weld Nos. WC-M202-38A-41A; dated December 10, 2004

Spare CRDM Closure Cap to Extension Pipe 4" Stainless Steel Weld Nos. WC-R116-2A - 5A; dated December 11, 2004

Spare CRDM Extension Pipe to Head Adaptor 4" Dissimilar Metal Weld Nos. WC-R114-2A - 5A; dated December 11, 2004

Instrument Port Head Adapter 4" Dissimilar Metal Weld Nos. WC-R110-34A, 35A, and 37A, dated December 11, 2004

Rod Travel Housing and Latch Housing 7.385" Weld Nos. WC-M009-1A, 10A-33A, 38A-41A; dated December 8, 2004

WesDyne International Automated Ultrasonic Examination Calibration Data Sheets

J-Groove Weld, Penetration Nos. 16, 20, 24, 13, 28, 29, 25, 21, 17, 33, 30, 10, 41, 40, 39, 38, 14, 18, 22, 26, 11, 27, 23, 19, 15, and 31; dated December 9, 2004

J-Groove Weld, Penetration Nos. 32, 12, and 1; dated December 9, 2004

J-Groove Weld, Penetration Nos. 31, 32, 28, 33, 30, 26, and 27; dated December 12, 2004

J-Groove Weld, Penetration Nos. 4, 5, 2, 34, 37, 35, and 3; dated December 11, 2004

J-Groove Weld, Vent (RVHVS) Vent; dated December 12, 2004

WesDyne International Ultrasonic Report Sheets

J-Groove Weld, Penetration No. 1; dated December 9, 2004

J-Groove Weld, Penetration No. 2; dated December 17, 2004

J-Groove Weld, Penetration Nos. 3, 4, and 5; dated December 12, 2004

J-Groove Weld, Penetration No. 10; dated December 9, 2004

J-Groove Weld, Penetration Nos. 22, 26, and 29; dated December 10, 2004

4OA5.3 TI 2515/163

Operating Procedure C20.3; Electric Power System Security Analysis; Revision 12

Abnormal Operating Procedure C20.3 AOP-1; Evaluating System Operating Conditions When Security Analysis is Out-of-Service; Revision 6

Abnormal Operating Procedure C20.3 AOP-12; Grid Voltage and Frequency Disturbances; Revision 2

Administrative Work Instruction 3.6.0; Reporting and NRC Notices of Violation; Revision 21

Emergency Plan Implementing Procedure F3-2; Classification of Emergencies; Revision 36

Emergency Plan Implementing Procedure F3-5; Emergency Notification; Revision 23

Procedure H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 9

Procedure H24.1, Appendix A; Phase One Risk Assessment Preparation; Revision 1

Xcel Energy System Operating Code GP 5.2; Revision 1

SP 1118; Verifying Paths from the Grid to Unit 1 Buses; Revision 17

SP 2118; Verifying Paths from the Grid to Unit 2 Buses; Revision 22

Emergency Procedure 1ECA-0.0; Loss of All AC Power; Revision 17

Emergency Procedure 2ECA-0.0; Loss of All AC Power; Revision 19

Emergency Procedure 1ECA-0.1; Loss of All Safeguards AC Power Without Safety Injection; Revision 13

Emergency Procedure 2ECA-0.1; Loss of All Safeguards AC Power Without Safety Injection; Revision 12

Emergency Procedure 1ECA-0.2; Loss of All Safeguards AC Power With Safety Injection; Revision 10

Emergency Procedure 2ECA-0.2; Loss of All Safeguards AC Power With Safety Injection; Revision 9

<u>4OA5.5</u> <u>Replacement Reactor Vessel Closure Head</u> (71007)

Design Change No. 03RV05 Part 1; Replace Unit 1 and 2 RV Heads and Associated Components; Revision 0

Design Report No. DAR-CI-04-20; Prairie Island Units 1 and 2, Core Exit Thermocouple Nozzle Assembly (CETNA), Design Report; Revision 0

Design Specification 418A07; Replacement Reactor Vessel Closure Head (RRVCH); Revision 2

Design Specification 418A08; CRDM; Revision 2

Document No. L5-01DR505; Prairie Island Unit 2, Replacement Reactor Vessel Closure Head, Justification for Nonconformance Reports of Replacement Reactor Vessel Closure Head; Revision 3

Document No. L5-01DR506; Prairie Island Unit 2, Replacement Reactor Vessel Closure Head, Additional Reconciliation of Applicable Documents for the Design Report; Revision 2

Document No. L5-01DR510; Prairie Island Unit 2, Replacement Reactor Vessel Closure Head, Design Report; Revision 1

Document No. L5-01DR511; Prairie Island Unit 2, Replacement Reactor Vessel Closure Head, Design Report L5-01DR510, Revision 1, Addendum; Revision 1

WCAP-16275-P, Revision 0, Addendum 2; Prairie Island Unit 2, Replacement Reactor Vessel Closure Head - Design Report; January 2005

WCAP-16275-P, Revision 0, Addendum 1; Prairie Island Unit 2, Replacement Reactor Vessel Closure Head - Design Report; December 2004

WCAP-16275-P; Prairie Island Unit 2, Replacement Reactor Vessel Closure Head - Design Report; Revision 0

Calculation Note No. CN-PAFM-04-84; Prairie Island Unit 2, RRVCH Fracture Evaluation; Revision 1

Calculation Note No. CN-RCDA-04-42; Point Beach Units 1 and 2, Replacement Reactor Vessel Closure Head - Vent Pipe ASME Code Evaluation; Revision 1

Calculation Note No. CN-RCDA-04-44; Point Beach Units 1 and 2, Replacement Reactor Vessel Closure Head - CRDM Head Adapter ASME Code Evaluation; Revision 1

Calculation Note No. CN-RCDA-04-47; Prairie Island Units 1 and 2, Replacement Reactor Vessel Closure Head - Analysis Procedure; Revision 0

Calculation Note No. CN-RCDA-04-75; Prairie Island Units 1 and 2, Replacement Head Project - Closure Head ASME Leakage Evaluation; Revision 1

Calculation Note No. CN-RCDA-04-79; Prairie Island Units 1 and 2, RVCH - Closure Head Adapter Bimetallic Weld and End Cap Analysis; Revision 0

Calculation Note No. CN-RCDA-04-93; Prairie Island Unit 2, RRVCH - Closure Head Lifting Lug Stress Analysis; Revision 0

Calculation Note No. CN-RCDA-04-100; Prairie Island Unit 2, RRVCH - ASME Section XI Code Reconciliation; Revision 1

Document No. PI-KCS-04-0001; Prairie Island Units 1 and 2, Control Rod Drive Mechanism, Design Report; Revision 2

Document No. PI-KCS-04-0002; Prairie Island Unit 2, Control Rod Drive Mechanism, Justification for Nonconformance Reports for Replacement Control Rod Drive Mechanism; Revision 3

Document No. PI-KCS-04-0006; Prairie Island Units 1 and 2, Control Rod Drive Mechanism, Design Data Report; Revision 1

Document No. PI-KCS-05-0001; Prairie Island Units 1 and 2, Control Rod Drive Mechanism, Design Report PI-KCS-04-0001, Revision 2, Addendum; Revision 0

WCAP-16276-P, Revision 0, Addendum 2; Prairie Island Units 1 and 2, Replacement Reactor Control Rod Drive Mechanism - Design Report; January 2005

WCAP-16276-P, Revision 0, Addendum 1; Prairie Island Units 1 and 2, Replacement Reactor Control Rod Drive Mechanism - Design Report; December 2004

WCAP-16276-P; Prairie Island Units 1 and 2, Replacement Reactor Control Rod Drive Mechanism - Design Report; Revision 0

Calculation Note No. WB-CN-ENG-04-20; Point Beach CRDM - Pressure Housing ASME Qualification; Revision 1

Calculation Note No. WB-CN-ENG-04-46; Prairie Island CRDM - ASME Code Section XI Reconciliation; Revision 1

Calculation Note No. WB-CN-ENG-04-51; Prairie Island Units 1 and 2, Replacement Reactor Vessel Closure Head, Applicability of the Point Beach Design Transients for Use in Stress Analysis; Revision 3

Calculation Note No. WB-CN-ENG-04-53; Prairie Island Units 1 and 2 - CRDM - Analysis Procedure; Revision 1

Calculation Note No. WB-CN-ENG-04-54; Prairie Island CRDM - Tentative Pressure Thickness Calculations per NB-3324; Revision 0

Calculation Note No. WB-CN-ENG-04-55; Prairie Island CRDM - Pressure Housing ASME Qualification; Revision 1

Calculation Note No. WB-CN-ENG-04-59; Prairie Island CRDM Seismic and LOCA Analysis; Revision 0

Westinghouse Letter LTR-RCDA-03-478, Revision 4; Subject: Kewaunee CRDM Heat Transfer; dated April 13, 2004

Westinghouse Letter LTR-RCDA-04-349; Subject: Prairie Island CRDM and RVCH Heat Transfer; dated April 30, 2004

Westinghouse Letter LTR-RCDA-04-473; Subject: Prairie Island Units 1 and 2 Replacement Reactor Vessel Closure Head - Applicability of Point Beach Head Adapter Stress Analysis; dated May 28, 2004

Westinghouse Letter LTR-RCDA-04-474; Subject: Prairie Island Units 1 and 2 Replacement Reactor Vessel Closure Head - Applicability of Point Beach Vent Pipe Stress Analysis; dated May 28, 2004

MHI Drawing L5-01DR109; Replacement Reactor Vessel Closure Head, Closure Head and Adapter Housing Assembly; Revision 2

MHI Drawing L5-01DR110; Replacement Reactor Vessel Closure Head, Instrumentation Port Head Adapter 1/2; Revision 3

MHI Drawing L5-01DR111; Replacement Reactor Vessel Closure Head, Instrumentation Port Head Adapter 2/2; Revision 3

MHI Drawing L5-01DR115; Replacement Reactor Vessel Closure Head 2/2; Revision 1

MHI Drawing L5-01DR171; Replacement Reactor Vessel Closure Head, As-Built Drawing (RV Closure Head) 1/3; Revision 2

MHI Drawing L5-01DR172; Replacement Reactor Vessel Closure Head, As-Built Drawing (RV Closure Head) 2/3; Revision 3

MHI Drawing L5-01DR173; Replacement Reactor Vessel Closure Head, As-Built Drawing (RV Closure Head) 3/3; Revision 3

MHI Drawing L5-03BM002; Prairie Island Control Rod Drive Mechanism, General Assembly; Revision 4

MHI Drawing L5-03BM003; Prairie Island Control Rod Drive Mechanism, Pressure Housing Assembly; Revision 2

MHI Drawing L5-03BM201; Prairie Island Control Rod Drive Mechanism, Rod Travel Housing; Revision 2

MHI Drawing L5-03BM202; Prairie Island Control Rod Drive Mechanism, One-Piece Latch Housing; Revision 5

4OA5.6 Head Assembly Upgrade Package (71007)

Design Change No. 03RV05 Part 2; RV Head Assembly Upgrade Package (HAUP); Revision 0

Design Specification No. 418A34; Head Assembly Upgrade Package (HAUP); Revision 5

Fabrication Specification No. 418A35; Head Assembly Upgrade Package (HAUP); Revision 4

Design Specification No. 418A76; Prairie Island Units 1 and 2, Head Assembly Upgrade Package, CRDM Cooling Fans; Revision 0

Design Specification No. 419A03; Piping Design Specification for Stress Analysis of ASME Section III RVLIS Class 1 Piping and Supports; Revision 0

Calculation No. 2005-05621; Analysis of Postulated Reactor Head Drop onto the Reactor Vessel Flange; Revision 0

Calculation No. 2005-05621; Analysis of Postulated Reactor Head Drop onto the Reactor Vessel Flange; Revision 1

Calculation No. PI-S-014; Reactor Head Drop Study; Revision 0

Calculation Note No. CN-RVHP-04-61; Prairie Island HAUP, Head Lift Rig Evaluation; Revision 2

Calculation Note No. CN-RVHP-04-66; Prairie Island HAUP - CRDM Seismic Spacer Plate Analysis; Revision 1

Calculation Note No. CN-RVHP-04-76; Prairie Island HAUP - Weight, CG, and Levelness Calculation; Revision 2

Calculation Note No. CN-RVHP-04-77; Prairie Island Units 1 and 2 HAUP - Missile Impact Analysis; Revision 1

Calculation Note No. CN-RVHP-04-80; Prairie Island Unit 2 - HAUP - RVLIS and RCGVS Piping Supports; Revision 2

Calculation Note No. CN-RVHP-04-83; Prairie Island Reactor Head Drop Analysis: Maximum Allowable Reactor Head Weight; Revision 1

Calculation Note No. CN-RVHP-04-86; Seismic Support Platform Bumper Pad and Adjustment Screw; Revision 1

Calculation Note No. CN-RVHP-04-87; Prairie Island HAUP, Plenum Stress Qualification; Revision 1

Calculation Note No. CN-RVHP-04-88; Prairie Island HAUP, Cable Bridge No. 1 Structural Analysis; Revision 2

Calculation Note No. CN-RVHP-04-90; Prairie Island Units 1 and 2 HAUP, Cooling Shroud Structural Analysis; Revision 1

Calculation Note No. CN-RVHP-04-91; Prairie Island Unit 2, RVLIS Piping Structural Analysis; Revision 2

Calculation Note No. CN-RVHP-04-94; Prairie Island HAUP, Messenger Wire Anchor and Platform Structural Analysis; Revision 1

Calculation Note No. CN-RVHP-04-128; Prairie Island HAUP, CRDM Seismic Support Evaluation; Revision 1

Calculation Note No. CN-RVHP-05-1; Prairie Island HAUP, Evaluation of Green Unistrut Cable Support Modification; Revision 1

Calculation Note No. CN-RVHP-05-19; NMC, Prairie Island Unit 2, RCGVS, and RVLIS ASME Section XI Code Reconciliation; Revision 0

Calculation Note No. CN-RVHP-05-27; Prairie Island Units 1 and 2 HAUP, Miscellaneous Hardware Seismic Evaluation; Revision 1

Calculation Note No. CN-RVHP-05-31; Prairie Island Lift Rig Tripod - Engagement of Threads in Clevises; Revision 0

Drawing NF-38434-2; Reactor Building Unit 1, Reactor Vessel Steel Supports; Revision K

Drawing NF-38435; Reactor Building Unit 1, Reactor Vessel Supports - Plans, Sections and Details; Revision F

Drawing NF-38436; Reactor Building Unit 1, Reactor Vessel Column Supports - Sections and Details; Revision F

Drawing NF-38490-2; Reactor Building Unit 2, Reactor Vessel Steel Supports; Revision C

Maintenance Procedure D58.1.9; Unit 1 - Reactor Vessel Head Removal; Revision 10

Maintenance Procedure D58.2.9; Unit 2 - Reactor Vessel Head Removal; Revision 10

NUREG-0800; Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants - Section 3.5.3, Barrier Design Procedures; July 1981

PINGP Updated Safety Analysis Report; Section 12.2.12.1.4: Containment Polar Crane Evaluation; Revision 25

CAP 041407; Westinghouse NSAL 05-1 Issue, RCGVS and RVLIS Not Analyzed for LOCA Movements; dated March 17, 2005

Corrective Action Reports Initiated as a Result of NRC Inspection

CAP 042052; Methodology Used for Reactor Head Drop Analysis Questioned; dated April 29, 2005

CA 010793; Methodology Used for Reactor Head Drop Analysis Questioned; dated May 18, 2005

CA 010794; Methodology Used for Reactor Head Drop Analysis Questioned; dated May 18, 2005

CE 007701; Methodology Used for Reactor Head Drop Analysis Questioned; dated May 2, 2005

CE 008035; Methodology Used for Reactor Head Drop Analysis Questioned; dated May 27, 2005

CAP 042117; Incomplete Documented Basis for Assumptions in Reactor Head Drop Analysis; dated May 3, 2005

OPR 000546; Operability Recommendation Related to CAP042117; Revision 0

OPR 000546; Operability Recommendation Related to CAP042117; Revision 1

OPR 000546; Operability Recommendation Related to CAP042117; Revision 2

OPR 000546; Operability Recommendation Related to CAP042117; Revision 3

CAP 043235; NRC Head Replacement Inspection - Lift Rig Analysis; dated June 27, 2005

CAP 043236; NRC Head Replacement Inspection - Missile Shield Analysis; dated June 27, 2005

CAP 043325; NRC Head Replacement Inspection Questions; dated July 5, 2005

CAP 043326; Lack of OE During Head Replacement Inspection; dated July 5, 2005

4OA5.6 Closure of URI

J. A. Grobe (DRS - Region III) Memorandum to S. C. Black (NRR); Request for Technical Assistance - Design Basis Assumptions for Non-Seismic Piping Failures at the Prairie Island Plant (TIA 2001-02); dated March 27, 2001

L. B. Marsh (NRR) Memorandum to J. A. Grobe (DRS - Region III); Response to Task Interface Agreement (TIA 2001-02) and Task Interface Agreement (TIA 2001-04) Regarding Evaluation of Service Water System Design Basis Requirements at Prairie Island (TAC No. MB1402, MB1403, MB1855, and MB1856); dated August 29, 2002

Nuclear Management Company, LLC; Prairie Island Nuclear Generating Plant, Units 1 and 2; License Amendment Request (LAR) for Resolution of Unresolved Items Related to Methods for Evaluation of Cooling Water System; dated May 3, 2004

M. L. Chawla (NRR) Letter to J. M. Solymossy (PINGP); Subject: Prairie Island Nuclear Generating Plant, Units 1 and 2 - Issuance of Amendments (TAC Nos. MC3043 and MC3044); dated May 10, 2005

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Documents Access and Management System
AISC	American Institute of Steel Construction
ALARA	As Low As Reasonably Achievable
ASME	American Society of Mechanical Engineers
BACC	Boric Acid Corrosion Control
CAP	Corrective Action Program Action Request
CFR	Code of Federal Regulations
CRDM	Control Rod Drive Mechanism
DAC	Distance Amplitude Correction
DRP	Division of Reactor Projects
EPRI	Electric Power Research Institute
ET	Eddy Current
HAUP	Head Assembly Upgrade Package
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IPEEE	Individual Plant Examination of External Events
IR	Inspection Report
ISI	Inservice Inspection
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
NCV	Non-Cited Violation
NMC	Nuclear Management Corporation, LLC
NRC	U.S. Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OPR	Operability Recommendation
OWA	Operator Workaround
PARS	Publicly Available Records
PINGP	Prairie Island Nuclear Generating Plant
PORV	Power Operated Relief Valve
RCGVS	Reactor Coolant Gas Ventilation System
RCS	Reactor Coolant System
RPVH	Reactor Pressure Vessel Head
RVCH	Reactor Vessel Closure Head
RVLIS	Reactor Vessel Level Indication System
RWP	Radiation Work Permit
SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection System
SP	Surveillance Procedure
TI	Temporary Instruction
TIA	Task Interface Agreement
TS	Technical Specifications
TSO	Transmission System Operator
URI	Unresolved Item
USAR	Updated Safety Analysis Report

UT	Ultrasonic Testing
VT	Visual Testing
WO	Work Orders