July 29, 2004

Mr. Joseph Solymossy
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 05000282/2004005;
05000306/2004005

Dear Mr. Solymossy:

On June 30, 2004, 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 14, 2004, with you and other members of your staff.

This inspection examined activities conducted under your licenses as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your licenses. 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 significance (Green), three of which resulted in violations of NRC requirements. However, because these violations were of very low safety significance and because the issues were entered into your 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, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Prairie Island Nuclear Generating Plant.

In 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/

Mohammed A. Shuaibi, Acting Chief
Branch 5
Division of Reactor Projects

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

Enclosure: Inspection Report 05000282/2004005;
05000306/2004005

cc w/encl: C. Anderson, Senior Vice President, Group Operations
J. Cowan, Executive Vice President and Chief Nuclear Officer
Regulatory Affairs Manager
J. Rogoff, Vice President, Counsel & Secretary
Nuclear Asset Manager
Tribal Council, Prairie Island Indian Community
Administrator, Goodhue County Courthouse
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of Commerce
Manager, Environmental Protection Division
Office of the Attorney General of Minnesota

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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:	05000282/2004005; 05000306/2004005
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, 2004
Inspectors:	J. Adams, Senior Resident Inspector D. Karjala, Resident Inspector S. Burton, Senior Resident Inspector, Monticello S. Ray, Senior Resident Inspector, Braidwood R. Daley, Senior Reactor Inspector M. Garza, Resident Inspector, Palisades L. Haeg, Reactor Inspector M. Holmberg, Senior Reactor Inspector M. Mitchell, Radiation Specialist D. Nelson, Radiation Specialist
Approved by:	M. Shuaibi, Acting Chief Branch 5 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000282/2004005, 05000306/2004005; 04/01/04 - 06/30/04; Prairie Island Nuclear Generating Plant, Units 1 and 2; Adverse Weather, Fire Protection, Heat Sink Performance, and Inservice Inspection Activities.

This report covers a 3-month period of baseline resident inspection and announced baseline radiation protection inspections. The inspectors also completed Temporary Instruction (TI) 2515/154, "Spent Fuel Material Control and Accounting At Nuclear Power Plants," and TI 2515/156, "Offsite Power System Operational Readiness." The inspections were conducted by the resident inspectors and inspectors from the Region III office. Four green findings were identified. 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. <u>Inspector-Identified and Self-Revealed Findings</u>

Cornerstone: Initiating Events

- Green. The inspectors identified loose decking materials installed on several equipment access platforms in the Prairie Island Nuclear Generating Plant switchyard. 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)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance regarding inadequate acceptance criteria for the licensee's Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment" heat exchanger inspections. The inspectors identified this issue during observation and review of the licensee's inspection of cooling water system heat exchangers. The finding constituted a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

The inspectors determined that the finding was more than minor because it adversely affected the licensee's ability to ensure that safety-related heat exchangers would be available, reliable, and capable of responding to initiating events to prevent undesirable consequences. The finding was of very low safety significance because the as-found and as-left conditions of the heat exchangers did not reveal any actual concerns with the operability of the heat exchangers. (Section 1RHS)

- Green. The inspectors identified a finding of very low safety significance regarding the licensee's failure to assure that the design basis of the plant was accurately translated and maintained in Attachment 1, "Inventory Control with a Safety Injection Pump," of Procedure F5, Appendix D, "Impact of Fire Outside Control/Relay Room." Specifically, limitations on the starting and stopping of the safety injection pump motors that prevent motor degradation were not translated from the vendor manual to the plant procedure. The finding constituted a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control."

  The inspectors determined that 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 to prevent undesirable consequences. The violation was determined to be of very low safety significance since the licensee was able to determine that any adverse effects to the pump motor would be long term in nature and would not affect immediate operability. (Section 4OA5.1)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a finding of very low safety significance regarding the licensee's failure to perform ultrasonic examinations on additional tubesheet-to-head welds in steam generators 12 and 21 following identification of indications on similar welds. The finding constituted a Non-Cited Violation of 10 CFR 50.55a(g)(4).

  The inspectors determined that the finding was more than minor because it affected the barrier integrity cornerstone objective of maintaining the reactor coolant system barrier integrity and if left uncorrected, could allow unacceptable piping system weld flaws to remain in-service. The finding was of very low safety significance because the welds were subsequently ultrasonically examined and the affected welds did not have flaws greater than that allowed by the American Society of Mechanical Engineers Code. (Section 1R08)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 was operated at or near full power throughout the inspection period except on June 25, 2004, when operators reduced power to about 35 percent for condenser cleaning and maintenance. The operators returned the unit to full power on June 28, 2004, where it operated for the remainder of the inspection period.

Unit 2 was operated at or near full power throughout the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1RHS Heat Sink Performance (71111.HS) (Pilot)

.1 As-Found Inspection of the 12 Diesel Driven Cooling Water Pump Heat Exchangers

a. Inspection Scope

On April 19, 2004, the inspectors observed the licensee's inspection of the following safety-related heat exchangers:

- 12 diesel driven cooling water pump (DDCLP) jacket water heat exchanger (HX), and
- 12 DDCLP right angle gear drive lubricating oil cooler.

These heat exchangers were selected for review because the cooling water system was ranked high in the plant specific risk assessment and functions to support the proper operation of nearly all safety-related mitigating systems and is the plant's connection to the ultimate heat sink. This inspection effort completed one heat sink inspection procedure sample.

The inspectors performed an independent as-found inspection of the HXs associated with the 12 DDCLP. Following the inspection, the inspectors discussed the as-found condition of the HXs with the system engineer and the Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," program engineer; reviewed the completed work package for the 12 DDCLP jacket water and right angle gear drive lubricating oil HXs; reviewed the licensee's response to GL 89-13; and reviewed the licensee's Procedure H21, "Generic Letter 89-13 Implementing Program," Revision 7, governing GL 89-13 heat exchanger inspections. The inspectors also discussed the adequacy of the acceptance criteria associated with DDCLP HX inspections with engineering and management personnel. The inspectors used the documents listed at the end of this report to evaluate this area.

In addition, the inspectors reviewed the 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. The inspectors reviewed the licensee's corrective actions for the issues documented in selected condition reports.

b. Findings

During the as-found inspection of the 12 DDCLP, the inspectors identified a finding associated with the licensee's failure to develop adequate acceptance criteria for the GL 89-13 HX inspections to ensure that the licensee's inspections were satisfactorily accomplished. This issue was considered to be of very low safety significance (Green) and was dispositioned as a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion V, "Instructions Procedures and Drawings."

Description

On April 19, 2004, during the licensee's inspection of the 12 DDCLP jacket water and right angle gear drive lubricating oil HXs, the inspectors performed an as-found inspection of each of the HXs. The inspectors reviewed work order (WO) 0309990 and noted that explicit as-found acceptance criteria were not included that identified the degree of plugging that could exist and still maintain the ability to perform required safety functions. The inspectors reviewed licensee Procedure H21 and noted that no tube plugging was allowed for either HX inspected. During the as-found inspection, the 12 DDCLP jacket water HX did not have any tubes plugged with service water debris; however, the right angle gear drive lubricating oil HX was found with 9 of 19 tubes plugged. The licensee's WO instructions directed maintenance personnel to document the extent of plugging, clean the HX, and return it to service.

The inspectors interviewed the GL 89-13 program engineer to assist in the assessment of the HX performance due to the plugging identified during the as-found inspection. The program engineer indicated that tube plugging calculations could not be completed since HX performance data was not available for the right angle gear drive lubricating oil HX. Lacking this information, the licensee had not established a tube plugging limit for this HX. Historically, some degree of tube plugging was noted during each annual inspection. This being the case, the inspectors concluded that the ability of the HXs to provide the necessary cooling to support the attainment of the DDCLP safety functions was indeterminate.

The inspectors concluded that the acceptance criteria provided in H21 (i.e., none) were inadequate to demonstrate that the DDCLP HXs, in the as-found condition, would have supported the fulfillment of the DDCLP safety functions; and were inadequate to demonstrate with reasonable confidence that the DDCLP HXs would retain a satisfactory level of performance until the next annual inspection and cleaning. The inspectors discussed this conclusion with members of the licensee's engineering staff with a focus on the historical operability of the DDCLP. The licensee performed Operability Recommendation (OPR) 000487, demonstrating that there was no impact on the operability of the 12 DDCLP. Licensee staff based their conclusion on information from the vendor's manual and limiting assumptions from plant accident analyses. The licensee entered the lack of acceptable performance criteria into their corrective action program (CAP) with action requests (ARs) 036271 and 037382. Action requests in the licensee's CAP are referred to as AR CAPs. Additionally, the licensee completed engineering analysis ENG-ME-573, which established tube plugging acceptance criteria for the 12 and 22 DDCLP jacket water HXs, and approved it on May 13, 2004.

Analysis

The inspectors determined that the failure to have an adequate acceptance criteria for the GL 89-13 HX inspections was a deficiency warranting a significance determination in accordance with NRC Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on June 20, 2003. The inspectors determined that the finding was more than minor because it involved the equipment performance attribute of the mitigating systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors evaluated the finding in accordance with IMC 0609, "Significance Determination Process." The finding was associated with the availability and reliability of a train in a mitigating system. Since the HX inspection results did not reveal any actual concerns with the operability of the HXs, the inspectors answered "no" to all of the SDP Phase 1 screening questions regarding mitigating systems. Therefore, this finding was considered to be of very low safety significance (Green).

Enforcement

Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedure, and Drawings," requires that instructions, procedures or drawings include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. On or before April 19, 2004, the licensee's Procedure H21 failed to include appropriate acceptance criteria for HX tube plugging to demonstrate that the as-found condition of the 12 DDCLP would support the fulfillment of the pump's safety functions; and would demonstrate with reasonable confidence that the HXs would retain a satisfactory level of performance until the next annual inspection. Because of the very low safety significance, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy
(NCV 05000282/2004005-01; 05000306/2004005-01).

.2 Biocide Treatment of the Cooling Water and Circulating Water Systems

a. Inspection Scope

On June 18, 2004, the inspectors observed members of the licensee's Operations Committee review the engineering analyses, assumptions, safety evaluations, and implementing procedure for the treatment of the cooling water and circulating water system. The documents listed at the end of this report were also used by the inspectors to evaluate this activity. This inspection effort completed one heat sink inspection sample.

The inspectors selected this sample for review because an increase in zebra mussel population in the intake structure exceeded the population assumed in a previous safety evaluation. This introduced a need to evaluate the impact of increased shell deposition on the risk-significant and safety-related cooling water system. Following Operations Committee approval of the biocide treatment, the inspectors performed an independent review of the engineering analyses, assumptions, safety evaluations, and implementing procedure comparing conclusions to actual plant conditions and equipment design. Additionally, on June 22 through June 25, 2004, following the application of the biocide, the inspectors made frequent in-field observations of the performance of the cooling water strainers, the cooling water pumps, and equipment served by the cooling water systems. The inspectors compared the actual equipment operating parameters to expected operating parameters. The inspectors also discussed with operators any evidence of adverse trends associated with equipment served by cooling water. The inspectors reviewed the 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.

1RST Post-Maintenance and Surveillance Testing (71111.ST) (Pilot)

.1 Post-Maintenance Testing

a. Inspection Scope

During this inspection period, the inspectors completed five post-maintenance inspection samples, comprised of the following post-maintenance testing (PMT) activities:

- 121 motor driven cooling water pump PMT following the replacement of a shaft O-ring on April 13, 2004;
- 12 DDCLP PMT following the performance of the annual preventive maintenance activity P3002-2-12 on April 19, 2004;
- D2 diesel generator PMT following maintenance on the engine governor to correct load oscillations on May 3, 2004;
- 11 auxiliary feedwater pump PMT following the replacement of the suction pressure switch on May 19, 2004; and
- D5 diesel generator PMT following the replacement of two pistons and two cylinder liners on June 11, 2004.

During the performance of these inspections, the inspectors completed in-plant observations and/or in-office reviews of documentation to ensure that testing activities met the following attributes:

- test results satisfied the test procedure acceptance criteria;
- effects of the testing had been adequately addressed prior to the commencement of the testing;
- measurement and test equipment calibrations were current;
- test equipment was used within the required range and accuracy;
- applicable prerequisites described in the test procedures were satisfied;

- affected systems or components were removed from service in accordance with approved procedures;
- testing activities 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;
- equipment was returned to a position or status required to support the operability of the system in accordance with approved procedures; and
- all problems identified during the testing were appropriately documented in the corrective action program.

The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Surveillance Testing

a. Inspection Scope

During this inspection period, the inspectors completed five inspection samples, comprised of the following surveillance testing activities:

- Surveillance Procedure (SP) 2334, D5 Diesel Generator 18 Month 24 Hour Load Test, Revision 9, on April 12, 2004;
- SP 1106A, 12 Diesel Cooling Water Pump Monthly Test, Revision 62, on April 23, 2004;
- SP 2089B, Train B Residual Heat Removal Pumps and Suction Valves from the Refueling Water Storage Tank Quarterly Test, Revision 5, on April 27, 2004;
- SP 1335, D2 Diesel Generator 18 Month 24 Hour Load Test, Revision 8, on June 6, 2004; and
- SP 2295, D5 Diesel Generator 6 Month Fast Start Test, Revision 27, on June 9, 2004.

Observation of surveillance testing activities associated with licensee SP 1106A completed the quarterly baseline inspection requirement to observe an inservice testing activity for a risk significant pump or valve.

During completion of the inspection samples, the inspectors observed in-plant activities and performed in-office review of 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 were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;

- plant equipment calibrations were correct, accurate, properly documented, and the calibration frequencies were in accordance with Technical Specifications (TS), the Updated Safety Analysis Report (USAR), procedures, and applicable commitments;
- measuring and test equipment calibrations were current;
- measuring and test equipment was used within the required range and accuracy;
- applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability;
- 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, American Society of Mechanical Engineers (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 associated equipment 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.

The documents reviewed by the inspectors are listed in the Attachment.

b. <u>Findings</u>

No findings of significance were identified.

1R01 <u>Adverse Weather Protection</u> (71111.01)

.1 <u>Hot Weather Preparations</u>

a. <u>Inspection Scope</u>

On May 17, 2004, the inspectors performed an in-office review of the summer plant operation program; USAR; applicable TS; and the Prairie Island Individual Plant Examination of External Events (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:

- screenhouse safety-related ventilation system (ZR);
- cooling tower substation system (ST) including transformers CT-11 and CT-12; and
- auxiliary and standby transformer system (AT).

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 AR 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.

.2 Tornado and High Winds

a. Inspection Scope

On May 6, 2004, 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; USAR; design basis documents for the Unit 1 and Unit 2 switchyard; and the Prairie Island 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 emergency diesel generator D1;
- the plant substation system (SY);
- the cooling tower substation system (ST) including transformers CT-11 and CT-12; and
- auxiliary and standby transformer system (AT).

b. Findings

Introduction

The inspectors identified a finding of very low safety significance for the failure to control materials in the switchyard. The finding was not considered a violation of regulatory requirements. The finding increased the probability of an initiating event because high velocity winds which typically accompany severe thunderstorms and tornados could cause unsecured material to become missile hazards, and these hazards increase the probability of damage to risk significant equipment which upon failure could cause an initiating event.

Description

On May 11, 2004, 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 of the switchyard, the inspectors identified that sections of the work platform grating adjacent to each of the manually operated disconnect switch operators had not been welded in place or otherwise secured. The inspectors concluded that high velocity winds combined with the close proximity of these loose materials increased the potential to damage switchyard transformer, breakers, disconnects, or other electrical equipment. This issue was entered into the licensee's corrective action program with AR CAPs 036622 and 037384. The licensee immediately removed the unsecured sections of deck grating from the switchyard following identification by the inspectors.

Analysis

Surveillance Procedure (SP) 1039 provides guidance to licensee personnel to inspect specified exterior areas of the plant and to secure or remove any missile hazards identified. 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 none of the equipment in the switchyard was safety-related equipment. Therefore, the inspectors' observations did not constitute a violation of NRC requirements

The inspectors determined that the failure of operations personnel to identify loose material in the switchyard was a performance deficiency which was related to the cross-cutting area of human performance. The inspectors reviewed this finding using the guidance contained in IMC 0612, Appendix B. 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 TS-required power supplies or a loss of off-site power, and thereby initiate a plant transient.

The inspectors evaluated the finding using IMC 0609. Using the Phase 1 Significance Determination Process worksheet for the initiating event cornerstone, transient initiator contributor, the inspectors determined 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).

The inspectors determined that the performance of the personnel performing the switchyard inspection required by SP 1039 was inadequate to identify loose materials that would become missile hazards in the event of a tornado or high wind adverse weather conditions. However, no violation of NRC requirements occurred because components described in 10 CFR Part 50, Appendix B, were not impacted by the finding (FIN 05000282/2004005-02; 05000306/2004005-02).

1R04 Equipment Alignment Partial System Walkdowns (71111.04)

a. Inspection Scope

The inspectors performed four inspection procedure 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. The inspectors utilized the valve and electric breaker checklists listed in the Attachment to verify that the components were properly positioned and that support systems were aligned 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 deficiencies. The inspectors reviewed outstanding work orders and AR CAPs associated with the trains to verify that those documents did not reveal issues that could affect train functions. 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:

- 12 auxiliary feedwater pump during the unavailability of the 11 auxiliary feedwater pump for planned maintenance on May 19, 2004;
- Diesel generator D1 during the unavailability of diesel generator D2 for a surveillance test on June 2, 2004;
- Diesel generator D6 during the unavailability of diesel generator D5 on June 9, 2004; and
- 121 safeguards chilled water system during the unavailability of components in the 122 safeguards chilled water system on June 21, 2004;

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Fire Protection Area Walkdowns

a. Inspection Scope

The inspectors performed in-office and in-plant reviews of portions of the licensee's Fire Hazards Analysis and Fire Strategies to verify consistency in the documented 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. The following eight fire areas were inspected by in-plant walkdowns completing eight fire protection zone walkdown samples:

- Fire Area 59, Unit 1 Auxiliary Building Mezzanine Level on May 12, 2004;
- Fire Area 73, Unit 2 Auxiliary Building Ground Floor on May 12, 2004;
- Fire Area 102, D6 Diesel Generator Room on May 17, 2004;
- Fire Area 118, 4 kV Bus 26; MCC 2TA2 Room on May 17, 2004;
- Fire Area 114, #22 D6 Fuel Oil Day Tank Room on May 17, 2004;
- Fire Area 128, 4 kV Bus 27 Room on May 17, 2004;
- Fire Area 20, Unit 1 4.16 kV Safeguards Switchgear Room (Bus 16) on June 4, 2004; and
- Fire Area 80, 480V Safeguards Switchgear Room (Bus 111) on June 4, 2004.

The inspectors also reviewed the AR CAP items listed in the Attachment to verify 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.

.2 Annual Fire Drill Observation

a. Inspection Scope

On May 18, 2004, inspectors observed an unannounced fire brigade drill. A large transformer fire was simulated at the Unit 1, 1R transformer. 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 also reviewed the AR CAP items listed in the Attachment to verify 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.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

On June 23, 2004, the inspectors performed an in-plant walkdown of the Unit 1 and Unit 2 auxiliary feedwater pump rooms completing one internal flood protection inspection sample. These areas of the Unit 1 and 2 contain safety-related and risk significant equipment including both trains of the auxiliary feedwater pumps, instrument air compressors, and remote shutdown panels. 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 an AR 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 Activities (71111.08)

a. Inspection Scope

On November 25, 2002, the inspectors identified an unresolved item (URI) 05000282/2002009-02; 05000306/2002009-02 associated with the licensee's failure to perform an ultrasonic (UT) examination of the Unit 1 steam generator (SG) 12 and Unit 2 SG 21 tubesheet-to-head (W-A) welds during the 1999 and 2002 refueling outages, respectively. On June 8, 2004, the inspectors reviewed the licensee's corrective actions for this condition including a review of the followup UT examinations completed on these welds. The inspectors completed this review to determine whether the licensee had met applicable requirements from the ASME Code Section XI. The specific documents that were reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

(1) Missed SG 12 and SG 21 Tubesheet-to-Head Weld UT Examinations

Introduction

The inspectors completed a review of a URI described in Inspection Report 05000282/2002009; 05000306/2002009, and concluded that the item constituted a finding for the licensee's failure to perform required UT examinations on welds in SGs 12 and 21. The finding constituted a violation of 10 CFR 50.55a(g)(4). The inspectors determined that the finding was of very low safety significance (Green).

Description

On November 26, 2002, the inspectors identified that the licensee had not performed UT examinations of the Unit 1 SG 12 and Unit 2 SG 21 W-A welds during the 1999 and 2002 refueling outages, respectively.

The licensee failed to examine the SG 12 W-A weld during the 1999 refueling outage after identification of a flaw that exceeded the ASME Code Section XI acceptance standards of Table IWB-3410-1 in the SG 11 W-A. The licensee had not inspected the SG 12 W-A weld since 1998. The inspectors were concerned that failure to examine this weld during the 1999 refueling outage could have allowed similar weld flaws in the W-A weld on SG 12 to reach an unacceptable size during plant operation. During the extent of condition review, the licensee identified that this condition also existed for the Unit 2 SG W-A welds. When the SG 22 W-A weld was examined in 2002, the licensee identified flaws in excess of acceptance standards of Table IWB-3410-1 and did not expand the inspection to SG 21. The licensee had last examined the SG 21 W-A weld during the 2000, Unit 2 refueling outage. The NRC had documented this issue as URI 05000282/2002009-02; 05000306/2002009-02 pending review of the licensee's corrective actions for this issue.

Additionally, the licensee had disagreed with the inspectors on the applicability of the ASME Code requirements in this area. Therefore, the inspectors had submitted this issue to the Office of Nuclear Reactor Regulation under task interface agreement (TIA) 2003-01 to obtain an NRC position on the Code requirements in dispute. The NRC staff provided the licensee an opportunity to review and comment on this TIA by letter dated February 6, 2003. The licensee staff responded to the NRC comments on this TIA by letter dated April 4, 2003. On May 27, 2003, the NRC issued a response letter to this TIA, which confirmed the applicability of these Code requirements for this issue.

Analysis

The licensee's failure to perform the required volumetric weld examinations of Unit 1 SG 12 and Unit 2 SG 21 W-A welds during the 1999 and 2002 refueling outages, respectively, constituted a performance deficiency warranting a significance determination. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, Appendix B, because, if left uncorrected, the failure to perform volumetric examinations could allow unacceptable piping system weld flaws to remain in-service. The finding was assigned to the barrier integrity cornerstone because the welds in question formed part of the reactor coolant system (RCS) boundary. Specifically, the licensee's failure to inspect these welds affected the barrier integrity cornerstone objective of maintaining reasonable assurance in the integrity of the physical RCS barrier. The inspectors determined that this finding could not be evaluated using the SDP in accordance with NRC IMC 0609, because the SDP for the barrier integrity cornerstone only applied to degraded systems/components, not to the program/process failures which could result in failure to detect degraded systems/components. Therefore, this finding was reviewed by the Regional Division of Reactor Safety 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). The inspectors determined that this issue was of very low safety significance because the licensee had completed a followup UT examination of the affected welds, and no flaws greater than that allowed by the ASME Code were identified.

Enforcement

Title 10 CFR 50.55a(g)(4) requires, in part, that throughout the service life of a pressurized water-cooled nuclear power facility, components must meet the requirements set forth in the ASME Code, Section XI. Section XI, Article IWB-2430, requires that "Examinations performed in accordance with Table IWB-2500-1 that reveal indications exceeding the acceptance standards of Table IWB-3410-1 shall be extended to include additional examinations at this outage. The additional examinations shall include the remaining welds, areas, or parts included in the inspection item listing..."

On May 22, 1999, the licensee performed an examination as described in Table IWB-2500-1 (Code item B.2.40) for Unit 1 SG 11 W-A weld, which revealed an indication that exceeded the acceptance standards of Table IWB-3410-1 and the licensee failed to include additional examinations of the remaining Code item B.2.40 welds of Table IWB-2500-1 during the 1999 outage. Specifically, the licensee failed to perform a volumetric examination of the W-A weld (Code item B.2.40 weld) on SG 12 during the 1999 outage and this weld had not received a volumetric inspection since 1998.

In addition, on February 15, 2002, the licensee performed an examination as described in Table IWB-2500-1 (Code item B.2.40) for Unit 2 SG 22 W-A weld, which revealed 14 indications that exceeded the acceptance standards of Table IWB-3410-1 and the licensee failed to include additional examinations of the remaining Code item B.2.40 welds of Table IWB-2500-1 during the 2002 Unit 2 refueling outage. Specifically, the licensee failed to perform a volumetric examination of the W-A weld (Code item

B.2.40 weld) on SG 21 during the February 2002 outage, and this weld had not received a volumetric inspection since May of 2000.

These issues are considered examples of a violation of 10 CFR 50.55a(g)(4). However, because of the very low safety significance of this finding and because the issue was entered into the licensee's corrective action program (CAP 026715, CAP 026755, CAP 037033), it is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the Enforcement Policy. (NCV 05000282/2004005-03; 05000306/2004005-03)

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On June 8, 2004, the inspectors performed a quarterly review of Crew 4 during licensed operator requalification training in the simulator, completing one licensed operator requalification inspection sample. The inspectors observed a training crew during an as-found requalification examination 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 the 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 TSs, 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 performed an issue/problem-oriented review of the steam exclusion systems, completing one maintenance effectiveness inspection sample. The inspectors reviewed repetitive maintenance activities to assess maintenance effectiveness, including maintenance rule (10 CFR 50.65) activities, work practices, and common cause issues. Inspection activities included, but were not limited to, the licensee's categorization of specific issues including evaluation of performance criteria, appropriate work practices, identification of common cause errors, extent of condition, and trending of key parameters. Additionally, the inspectors reviewed implementation of the maintenance rule requirements, including a review of scoping, goal-setting, performance monitoring, short-term and long-term corrective actions, functional failure determinations associated with reviewed condition reports, and current equipment performance status.

For the systems reviewed, the inspectors reviewed significant AR CAPs to verify that failures were properly identified, classified, and corrected, and that unavailable time had been properly calculated. The inspectors reviewed other AR CAPs to verify that problems associated with steam exclusion equipment relied upon to protect risk significant mitigating equipment from the adverse effects of a high energy line break event 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.

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

a. Inspection Scope

The inspectors reviewed risk assessments for the following five maintenance activities, completing five risk assessment and emergent work control inspection samples:

- unavailability of circuit breaker 12RYBT for planned maintenance on April 6, 2004;
- unavailability of the 11 Auxiliary Feedwater Pump and the 125 Service Air Compressor for planned maintenance on May 18, 2004;
- unavailability of Diesel Generator D-5 and the Red Rock transmission line for planned maintenance on June 8, 2004;
- unavailability of the 21 SG Power Operated Relief Valve, the 21 Component Cooling Water Pump, and the 21 Diesel Generator D5 Fuel Oil Transfer Pump for planned maintenance along with unplanned unavailability of the 22 Charging Pump on June 15, 2004; and
- unavailability of the 12 Auxiliary Feedwater Pump, the 11 Charging Pump, and the 22 Reactor Makeup Pump for planned maintenance on June 29, 2004

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 associated with maintenance activities. 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)

a. Inspection Scope

On June 16, 2004, the inspectors discussed with operators the actions taken to address an emergent failure of the 22 charging pump coupling. The inspectors also performed an in-office review of operator actions and compared their actions to the actions specified in annunciator response and abnormal operating procedures. The inspectors reviewed control room instrumentation records and compared the plant's response to the response expected for a failure of the 22 charging pump.

The inspectors reviewed the AR CAPs listed in the Attachment to verify that the licensee was identifying equipment and human performance 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.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the technical adequacy of six operability evaluations completing five operability evaluation inspection samples. The inspectors completed 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, 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 Administrative Work Instruction 5AWI 3.15.5, "Operability Determinations." The following operability evaluations were reviewed:

- Condition Evaluation (CE) 004992, which documented the bases to justify operability of Steam Exclusion Dampers CD-34199 and CD-34201 following the licensee's discovery that the dampers would not fully close, on June 4, 2004;
- OPR 000489, which documented the bases to justify operability of the 12 Shield Building Special Ventilation exhaust filter when the temperature switch did not trip, on June 7, 2004;
- Apparent Cause Evaluation (ACE) 008837, which documented the bases to justify operability of the 121 Control Room Air Handler after the air handler fan stopped, the cause of the problem could not be found, and the work order to replace the circuit breaker was not performed as scheduled; on June 7, 2004;

- OPR 000486, which documented the bases to justify operability of diesel generator D5 with thermostatic elements that were found with their temperature response test results outside of the required tolerance, on June 9, 2004;
- OPR 000496, which documented the bases to justify operability of diesel generator D5 with higher than normal crankcase pressure oscillations, on June 13, 2004; and
- OPR 000497, which documented the bases to justify leakage through the letdown isolation valves was less than the TS limit, on June 21, 2004.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (OWAs) (71111.16)

.1 Cumulative Effects of OWAs

a. Inspection Scope

On June 25, 2004, 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 reviewed operator logs, AR CAPs, and Operating Information documents to determine if there were OWAs that had not been evaluated. The inspectors used the documents listed in the Attachment to evaluate the list of OWAs.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation and Simulator-Based Training (71114.06)

a. Inspection Scope

The inspectors observed the licensee perform an emergency preparedness drill on May 5, 2004. This inspection effort completed one emergency planning drill evaluation sample.

The inspectors observed activities in the control room simulator and Emergency Operations Facility and attended the post-drill critique on May 6, 2004. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the drill performance and ensure that the licensee evaluators noted the same weaknesses and deficiencies and entered them into the corrective action program. The inspectors placed emphasis on observations regarding event classification, notifications, protective action recommendations, and site evacuation and accountability activities. The documents reviewed by the inspectors are listed in the Attachment.

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 Plant Walkdowns and Radiological Boundary Verification

a. Inspection Scope

The inspectors walked down and surveyed (using an NRC survey meter) selected radiologically controlled areas within the plant to verify the adequacy of radiological boundaries and postings and to verify that the selected areas were properly controlled in accordance with 10 CFR Part 20, licensee procedures, and the TS. This represents one inspection sample.

b. Findings

No findings of significance were identified

2OS2 As Low As Is Reasonably Achievable (ALARA) Planning and Controls (71121.02)

.1 ALARA Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends, and ongoing and planned activities in order to assess current performance and exposure challenges. The inspectors reviewed procedures associated with maintaining occupational exposures ALARA and processes used to estimate and track work activity specific exposures. This review represented two inspection samples.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee’s list of work activities in progress associated with steam generator replacement and reviewed the following three work activities of highest exposure significance:

- Containment Scaffold;
- Containment Structural Mods; and
- Primary and Secondary Side Water Level Control Plan.

For these three activities, the inspectors reviewed the ALARA work activity evaluations completed for the upcoming steam generator replacement outage. The inspectors reviewed exposure estimates and exposure mitigation requirements completed as of the date of the inspection. The inspectors performed this review 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 whether the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry experience in steam generator replacement, and/or special circumstances.

The inspectors evaluated if work activity planning included consideration of the benefits of dose rate reduction activities such as shielding provided by water filled components/piping, job scheduling, and shielding and scaffolding installation and removal activities. This review represented three inspection samples.

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 radiation safety cornerstone met the requirements of 10 CFR 20.1101(c).

Chosen corrective action reports related to the ALARA program were reviewed and staff members were interviewed to verify that follow-up activities had been conducted in an effective and timely manner commensurate with their importance to safety and risk using the following criteria:

- 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 program; and
- Implementation/consideration of risk significant operational experience feedback.

The licensee's corrective action program was also reviewed to determine if repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution had been addressed. This review represented three inspection samples.

b. Findings

No findings of significance were identified.

2PS3 Radiological Environmental Monitoring and Radioactive Material Control Programs (71122.03)

.1 Inspection Planning and In-Office Inspection

a. Inspection Scope

The inspectors reviewed the 2002 Environmental Monitoring Report and licensee assessment results to verify that the Radiological Environmental Monitoring Program (REMP) was implemented as required by TS and the Offsite Dose Calculation Manual (ODCM). The inspectors reviewed the report for changes to the ODCM with respect to environmental monitoring, commitments in terms of sampling locations, monitoring and measurement frequencies, land use census, interlaboratory comparison program, and analysis of data. The inspectors reviewed the ODCM to identify environmental monitoring stations and reviewed licensee self-assessments, audits, LERs, and interlaboratory comparison program results. The inspectors reviewed the USAR for information regarding the environmental monitoring program and meteorological monitoring instrumentation. The inspectors reviewed the scope of the licensee's audit program to verify that it met the requirements of 10 CFR 20.1101(c). This represents one inspection sample.

b. Findings

No findings of significance were identified.

.2 Onsite Inspection

a. Inspection Scope

The inspectors walked down all of the air sampling stations and approximately 10 percent of the thermoluminescence dosimeter (TLD) monitoring stations to determine whether they were located as described in the ODCM and to determine the equipment material condition. This represents one inspection sample.

The inspectors observed the collection and preparation of a variety of environmental samples (e.g., ground and surface water, milk, vegetation, sediment, and soil) and verified that environmental sampling was representative of the release pathways as specified in the ODCM and that sampling techniques are in accordance with procedures. This represents one inspection sample.

The inspectors verified that the meteorological instruments were operable, calibrated, and maintained in accordance with guidance contained in the USAR, NRC Safety Guide 23, and licensee procedures. The inspectors verified that the meteorological data readout and recording instruments in the control room and at the tower were operable. The inspectors compared readout data (i.e., wind speed, wind direction, and delta temperature) in the control room and at the meteorological tower to identify whether there were any line loss differences. This represents one inspection sample.

The inspectors reviewed each event documented in the 2002 Environmental Monitoring Report which involved a missed sample, inoperable sampler, lost TLD, or anomalous measurement for the cause and corrective actions and reviewed the licensee's assessment of any positive sample results (i.e., licensed radioactive material detected above the lower limits of detection). The inspectors reviewed the associated radioactive effluent release data. This represents one inspection sample.

The inspectors reviewed significant changes made by the licensee to the ODCM as the result of changes to the land census or sampler station modifications since the last inspection. The inspectors reviewed technical justifications for changed sampling locations. The inspectors verified that the licensee performed the reviews required to ensure that the changes did not affect its ability to monitor the impacts of radioactive effluent releases on the environment. This represents one inspection sample.

The inspectors reviewed the calibration and maintenance records for five air samplers.

The inspectors reviewed the results of the REMP sample vendor's quality control program including the interlaboratory comparison program to verify the adequacy of the vendor's program and the corrective actions for any identified deficiencies. The inspectors reviewed an audit the licensee performed on the vendor's program. The inspectors reviewed the audit results to determine whether the licensee met the TS/ODCM requirements. This represents one inspection sample.

b. Findings

No findings of significance were identified.

.3 Unrestricted Release of Material from the Radiologically Controlled Area

a. Inspection Scope

The inspectors observed the access point where the licensee monitors potentially contaminated material leaving the Radiologically Controlled Area and inspected the methods used for control, survey, and release from this area. The inspectors observed the performance of personnel surveying and releasing material for unrestricted use to verify that the work was performed in accordance with plant procedures. This represents one inspection sample.

The inspectors verified that the radiation monitoring instrumentation was appropriate for the radiation types present and was calibrated with appropriate radiation sources. The inspectors reviewed the licensee's criteria for the survey and release of potentially contaminated material and verified that there was guidance on how to respond to an alarm which indicates the presence of licensed radioactive material. The inspectors reviewed the licensee's equipment to ensure the radiation detection sensitivities were consistent with the NRC guidance contained in IE Circular 81-07 and IE Information Notice 85-92 for surface contamination and Health Physics Position (HPPOS)-221 for volumetrically contaminated material. The inspectors verified that the licensee performed radiation surveys to detect radionuclides that decay via electron capture. The inspectors reviewed the licensee's procedures and records to verify that the radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters (i.e., counting times and background radiation levels). The inspectors verified that the licensee had not established a "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator level or locating the instrument in a high radiation background area. This represents one inspection sample.

b. Findings

No findings of significance were identified.

.4 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed corrective action program documents addressing issues involving the REMP as well as a Generation Quality Services audit of the environmental monitoring program and observation reports addressing the REMP to determine if problems were being identified and entered into the corrective action program for timely resolution. This represents one inspection sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstones: Initiating Events and Mitigating Systems

a. Inspection Scope

The inspectors reviewed the licensee submittals for two performance indicators for Prairie Island Units 1 and 2, completing four performance indicator verification inspection procedure samples. The inspectors reviewed the documents listed in the Attachment.

The inspectors used performance indicator guidance and definitions contained in Nuclear Energy Institute Document 99-02, Revision 2, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the performance indicator data. The inspectors' review included, but was not limited to, conditions and data from logs, LERs, condition reports, and calculations for each performance indicator specified. The inspectors also reviewed the AR CAP items listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with corrective action procedures.

The licensee's reports of the following performance indicators were verified:

Unit 1

- Safety System Unavailability - Residual Heat Removal System for the 2nd quarter 2003 through the 1st quarter 2004; and
- Reactor Scrams with Loss of Normal Heat Removal for the 2nd quarter 2003 through the 1st quarter 2004.

Unit 2

- Safety System Unavailability - Residual Heat Removal System for the 2nd quarter 2003 through the 1st quarter 2004; and
- Reactor Scrams with Loss of Normal Heat Removal for the 2nd quarter 2003 through the 1st quarter 2004.

b. Findings

No findings of significance were identified.

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. Minor issues entered into the licensee's corrective action program as a result of inspector observations are covered by the list of documents included in the Attachment.

b. Findings

No findings of significance were identified.

.2 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. The effectiveness of the licensee trending activities was 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. This inspection effort completed one semi-annual trending inspection sample. 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;
- audit reports;
- self assessment reports;
- maintenance rule reports; and
- corrective action backlog reports.

The documents reviewed by the inspectors are listed in the Attachment.

b. Findings and Observations

No findings of significance were identified. The inspectors reviewed the status of the trending and coding activities resulting from the Problem Identification and Resolution Inspection performed in September 2003. An observation from that inspection was that coding of corrective action program data was inconsistent, raising a question of the usefulness of the trend data. The review performed during this inspection revealed that Performance Assessment staff are assigning trend codes to items in the corrective action program, but the assignment of trend codes by line departments is inconsistent and there have been no significant improvements in coding or trending. Further, it was noted that while individual equipment performance trends are monitored, there is no systematic review of corrective action program items, WOs, or other data to identify potential generic or common cause trends in equipment performance.

4OA5 Other Activities

.1 (Closed) Unresolved Item 05000282/2004002-01; 05000306/2004002-01: Cycling of Safety Injection Pumps for Fire Scenarios. The inspectors identified that the licensee's procedures for post-fire safe shutdown in certain fire areas required the cycling of safety injection (SI) pumps to accomplish inventory and pressure control. The inspectors were concerned that cycling SI pumps could adversely affect the pump motors and impact safe shutdown capability. (See Section 1R05.4b of Inspection Report 05000282/2004002; 05000306/2004002 for details.)

Introduction

The inspectors identified that design basis limitations associated with the starting of the SI pumps had not been translated into the plant's procedure for responding to a fire outside of the Control/Relay Room. This failure to assure that the design basis of the plant was accurately translated and maintained in plant procedures was determined to be of very low safety significance and was dispositioned as a Green Non-Cited Violation of the requirements in 10 CFR Part 50, Appendix B, Criterion III, “Design Control.”

Description

For certain fire scenarios at the Prairie Island Nuclear Generating Plant (PINGP), the inventory and pressure control functions were accomplished using an SI pump. Attachment 1, “Inventory Control with a Safety Injection Pump,” of Procedure F5, Appendix D, “Impact of Fire Outside Control/Relay Room,” directed operators to provide makeup to the reactor coolant system using an SI pump. To accomplish this function, Attachment 1 directed the operators to maintain a desired pressurizer level control band of 15 to 50 percent and to start and stop the SI pump, as necessary, to maintain pressurizer level during cooldown. Based upon this guidance, the inspectors were concerned that continuously cycling the SI pumps in accordance with the guidance in this procedure could adversely affect the pump motors and impact safe shutdown capability.

Attachment 1 of Procedure F5, Appendix D, provided restrictions on cycling of an SI pump by specifying that “the number of cycles of the SI pump should be minimized.” However, the inspection team discovered that the vendor manual for the pump contained the following limitations:

> “The pump can be started two times in succession cold, and once at operating temperature. If the pump runs for 20 minutes or more at operating speed, it can be restarted immediately. If it runs less than 20 minutes at speed and then stops or is shut down, it must remain shut down for 40 minutes before restarting.”

The inspectors identified that the specific limitations of the vendor manual had not been incorporated into Attachment 1. In addition, the inspectors interviewed licensed operators in regard to the actions specified by Attachment 1. The operators were not aware of any specific starting limitations, such as those specified by the vendor, for the SI pumps. As such, the inspectors determined that operators could have operated an SI pump outside of the vendor limitations during a fire scenario. Operation outside of the vendor limitations for the pump motor could lead to long term, and under more severe operating scenarios, short term, damage to the motor.

In response to the inspectors’ concerns, the licensee initiated CAP 035339 and revised Attachment 1 of Procedure F5, Appendix D, on February 13, 2004, to incorporate the vendor limitations. Preliminary evaluations performed by the licensee to address the capabilities of the SI pump during post-fire scenarios were initially insufficient for the inspectors to determine the safety significance of this issue. However, based upon subsequent evaluations performed by both the licensee and Westinghouse, the licensee was able to determine that the most probable cooldown rates for a post-fire safe shutdown scenario would not result in pump cyclings that exceeded the vendor manual limitations. Additionally, based upon the possible cooldown scenarios, even if the pump motor limitations were exceeded, the adverse effects to the motor would be long term in nature and would not effect immediate operability of the pump.

Analysis

The inspectors determined that the failure to incorporate the vendor technical manual pump cycling limitations was a performance deficiency warranting a significance evaluation. The inspectors evaluated the finding using the guidance in IMC 0612, Appendix B, and determined the finding to be more than minor, because it affected the mitigating systems cornerstone objective. The inspectors evaluated the finding in accordance with IMC 0609, Appendix A. The finding screened as Green in the SDP Phase 1, because all applicable Phase 1 questions were answered "No." This failure to assure that the design basis of the plant was accurately translated and maintained in plant procedures was determined to be of very low safety significance, since the licensee was able to determine that any adverse effects to the pump motor would be long term in nature and would not affect immediate operability.

Enforcement

Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to this, the licensee failed to assure that the design basis of the plant was accurately translated and maintained in Attachment 1, "Inventory Control with a Safety Injection Pump," of Procedure F5, Appendix D, "Impact of Fire Outside Control/Relay Room." Specifically, limitations on the starting and stopping of the SI pump motors that prevent motor degradation were not translated from the vendor manual to the plant procedure. The results of this violation were determined to be of very low safety significance, since the licensee was able to determine that any adverse effects to the pump motor would be long term in nature and would not affect immediate operability. Therefore, since this violation was captured in the licensee's corrective action program (CAP 035339), it is considered a Non-Cited Violation (NCV 05000282/2004005-04; 05000306/2004005-04) consistent with Section VI.A.1 of the NRC Enforcement Policy.

.2 (Closed) URI 50-282/00-13-04; 50-306/00-13-04: Unable to Determine the Validity of the Failure to Use Single Failure Criteria in Circumstances Caused by External Events

Note: This issue was originally identified as URI 50-282/00-13-02; 50-306/00-13-02 in Inspection Report 50-282/00-13(DRS); 50-306/00-13(DRS), dated December 20, 2000, but through administrative error is being tracked via the above number by the NRC.

Introduction: A concern was identified regarding the licensee's practice of not considering single failure criteria for external type events.

Description: During the first biennial baseline safety system design and performance capability inspection (NRC Inspection Report 50-282/00-13(DRS); 50-306/00-13(DRS), dated December 20, 2000), the inspectors identified that the cooling water (CL) system emergency dump flow pathway was vulnerable to a single failure, a concern having potentially more than very low safety significance.

Portions of the CL return pathways for both divisions were routed through non-seismically qualified piping in the non-seismically qualified turbine building. For a seismic event, the potential existed that these pathways could be blocked. Therefore, an alternate safety-related return flowpath (emergency dump) was provided in the auxiliary building. This flowpath was normally isolated by motor-operated-valve MV32038, and operator action was required to open this valve when necessary. A single failure of this valve to open when required could leave all safety-related heat loads in both divisions with no CL flow. The flow through the CL pumps could be reduced to below minimum flow adequacy.

Although operators might be dispatched to manually open the dump valve, the inspectors considered it unlikely that this condition could be diagnosed and the valve manually opened locally in time to prevent failures of the Unit 1 diesel generators. Additionally, if the failure were mechanical, manual operation could be precluded.

Licensee personnel maintained that considering single failure for external events, such as a seismic event, was outside their licensing basis. No documentation was identified to support this position, and all USAR statements reviewed by the inspectors concerning single failure indicated that consideration of single failure was required for all events requiring safe shutdown. However, external events were not explicitly addressed in those statements. The inspectors also noted that external events, such as earthquake, tornado, or flood, could cause a loss-of-offsite power (LOOP), and a LOOP was discussed in USAR Section 14.4.11, "Loss of All AC Power to the Station Auxiliaries (LOOP)." This USAR section explicitly required single failure consideration for a LOOP, but again did not directly address external events.

During discussions with licensee personnel, the inspectors learned that it was common practice for the licensee to not consider single failure criteria for external events, which the licensee considered to be acceptable and which had been accepted by the NRC for the Prairie Island plant. The inspectors were unable to determine the validity of this approach to not use single failure criteria for problems when external events occurred. Pending review and determination of the validity of this approach by NRC headquarters, this issue was considered an Unresolved Item.

<u>Analysis</u>: The licensee entered the concern of not considering single failure criteria for external events into its corrective action program. The licensee documented its conclusion that single failure criteria for external events is outside of design basis in CAP018907, "Review and Document the Site Position of Single Failure for External Events Is Outside of Design Basis." In addition, in the response to Task Interface Agreement (TIA) 2001-10, related to the requirement for emergency diesel generators to meet single failure criteria for external events, Office of Nuclear Reactor Regulation (NRR) staff summarized, "neither the General Design Criteria (GDC), the Final Safety Analysis Report (FSAR), or the staff's September 28, 1972, safety evaluation, specify that the emergency AC power system is required to meet single failure criteria coincident with an external event."

In the response to TIA 2001-04, regarding NRR's evaluation of service water system design basis requirements at Prairie Island, NRR staff considered it acceptable to have only a single seismic Category I flow path that is vulnerable to a single failure provided that the licensee has demonstrated that ample time existed for operator action to overcome the single active failure. NRR staff also indicated that: (1) it would not be necessary to assume complete blockage of the redundant non-seismic flow paths if they are located in a portion of the turbine building that is designed to withstand a design-basis earthquake; and (2) a complete rupture of one of the non-seismic discharge pipes should be assumed when performing the analysis to determine the available time for operator action.

Calculation ENG-ME-404, Revision 1, “Loss of Off Site Power w/One CL Pump,” demonstrated sufficient time existed for operator action to overcome a LOOP coincident with a single active failure. In addition, the inspectors performed walkdowns in the turbine building and confirmed that it was not necessary to assume complete blockage of the redundant non-seismic CL flow paths. Since the effect of a complete rupture of one of the non-seismic CL discharge pipes, the only remaining part of this issue, is being addressed by the licensee in their response to URI 50-282/00-13-06; 50-306/00-13-06, NRC staff have determined that it is not necessary to have this item remain open. This item is closed.

.3 Spent Fuel Material Control and Accounting At Nuclear Power Plants, Temporary Instruction (TI) 2515/154

a. Inspection Scope

The inspectors interviewed the licensee’s Special Nuclear Material (SNM) custodian using the questions in TI 2515/154 as a guideline. The inspectors reviewed licensee procedures governing the movement and accounting of SNM, and verified the procedures were adequate for the relevant task, approved at an appropriate management level, and controlled in accordance with the licensee’s document control policy. The inspectors reviewed inventory records for SNM as well as non-fuel items stored in the spent fuel pool. Documents reviewed as part of this TI are listed in the Attachment. This TI was not a part of the baseline inspection program and was therefore not considered a sample. Phases I and II of the TI are considered complete.

b. Findings

No findings of significance were identified.

.4 TI 2515/156, Offsite Power System Operational Readiness

a. Scope

The inspectors completed TI 2515/156 to confirm, through interviews of operations, engineering and maintenance staff, and direct observation, the operational readiness of offsite power systems in accordance with NRC requirements. The inspectors confirmed the information received through interviews regarding: design interface between the nuclear power plant and the transmission system operator; the assessment of risk associated with performing work on the offsite or emergency onsite power systems; and operability of the offsite power supply during the August 14, 2003, electrical grid event. The inspectors reviewed the assumptions made in the licensee’s station blackout analysis and compared it to the events listed in the Loss of Offsite Power Events chart provided in Attachment B to TI 2515/156, to verify that the coping time was unaffected by the data provided in the chart. The inspectors reviewed the licensee's assessment of the industry operating experience resulting from the grid event, verified that this assessment was entered into the corrective action program and that appropriate corrective actions associated with the assessment were planned or implemented as necessary. Documents reviewed for this TI are listed in the Attachment.

b. Observations and Findings

No findings of significance were identified. Based on inspection, no immediate operability issues were identified. In accordance with TI 2515/156 reporting requirements, the inspectors provided the required data to NRC headquarters staff for further analysis.

.4 Review of Institute of Nuclear Power Operations Report

During the week of April 11, 2004, the inspectors completed a review of the Institute of Nuclear Power Operations final report, May 2003 Evaluation.

4OA6 Meeting(s)

.1 Exit Meeting

The inspectors presented the inspection results to Mr. J. Solymossy and other members of licensee management at the conclusion of the inspection on July 14, 2004. The licensee did not identify any materials examined during the inspection as proprietary in nature.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Radiation Protection inspection with Mr. J. Solymossy, Site Vice President, on May 6, 2004.
- Occupational Radiation Safety ALARA Planning and Controls with Mr. J. Solymossy, Site Vice President, on May 21, 2004.
- Inservice Inspection with Mr. S. McCall, Program Engineering Manager, on June 8, 2004.
- Closure of URI 50-282/00-13-04; 50-306/00-13-04, with Tim Allen, Acting Plant Manager on July 26, 2004

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
J. Solymossy, Site Vice President
R. Graham, Director of Operations
M. Werner, Plant Manager
T. Allen, Outage and Scheduling Manager
T. Bacon, Operations Training Supervisor
T. Downing, Engineering Supervisor
S. Hanson, ISI Program Engineer
D. Herling, Assistant Operations Manager
P. Huffman, Operations Manager
J. Kivi, Regulatory Affairs Engineer
J. Lash, Training Manager
K. Ludwig, Maintenance Manager
S. McCall, Program Engineering Manager
S. Northard, Director of Engineering
G. Park, Fleet ISI Supervisor
A. Qualantone, Security Manager
G. Salamon, Regulatory Affairs Manager
T. Taylor, Performance Assessment Manager
J. Wren, NDE Program Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000282/2004005-01 05000306/2004005-01	NCV	Inappropriate Acceptance Criteria for Diesel Driven Cooling Water Pump Heat Exchangers
05000282/2004005-02 05000306/2004005-02	FIN	Missile Hazards in the Switch Yard
05000282/2004005-03 05000306/2004005-03	NCV	Missed UT Examinations for SG 12 and SG 21 W-A Welds
05000282/2004005-04 05000306/2004005-04	NCV	Cycling of Safety Injection Pumps for Fire Scenarios

Closed

50-282/00-13-04, 50-306/00-13-04	URI	Unable to Determine the Validity of the Failure to Use Single Failure Criteria in Circumstances Caused by External Events
05000282/2004005-01 05000306/2004005-01	NCV	Inappropriate Acceptance Criteria for Diesel Driven Cooling Water Pump Heat Exchangers
05000282/2004005-02 05000306/2004005-02	FIN	Missile Hazards in the Switch Yard
05000282/2004005-03 05000306/2004005-03	NCV	Missed UT Examinations for SG 12 and SG 21 W-A Welds
05000282/2004005-04 05000306/2004005-04	NCV	Cycling of Safety Injection Pumps for Fire Scenarios
05000282/2002009-02 05000306/2002009-02	URI	Missed UT Examinations for SG 12 and SG 21 W-A Welds
05000282/2004002-01 05000306/2004002-01	URI	Cycling of Safety Injection Pumps for Fire Scenarios

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.

1RHS Heat Sink

12 Diesel Driven Cooling Water Pump Heat Sink Inspection

Work Order 0309990; Preventive Maintenance (PM) 3002-2-12; 12 Diesel Driven Cooling Water Pump Annual Inspection
PINGP Procedure H21; Generic Letter 89-13 Implementing Program; Revision 7
PINGP Design Basis Document (DBD) System 35; Cooling Water System; Revision 4W
AR CAP 036271; Tubes Found Plugged in 12 Diesel Driven Cooling Water Pump Gear Oil Cooler
AR CAP 036300; Minor Debris Found in 12 DDCLP OIL Cooler Tube
AR CAP 036311; Surveillance Procedure 1128 Flush Was Not Performed Prior to PM-3108-2 Inspection.
CE 005128; Tubes Found Plugged in 12 Diesel Driven Cooling Water Pump Gear Oil Cooler
ACE; Tubes Found Plugged in 12 Diesel Driven Cooling Water Pump Gear Oil Cooler
OPR 000487; Tubes Found Plugged in 12 Diesel Driven Cooling Water Pump Gear Oil Cooler
Western Gear Corporation Technical Manual XH-48-71; Pumpmaster Right Angle Pump Drive

Biocide Treatment of Cooling Water and Circulating Water Systems

PINGP Procedure D 104.1; Zebra Mussel Control Treatment; Revision 0
Safety Evaluation 1025; D 104.1; Zebra Mussel Control Treatment; Revision 0
Safety Evaluation 2155; Engineering Analysis ENG-ME-577: Revision 0
Operating Committee Meeting #2804 Documentation Package; dated June 18, 2004
Engineering Analysis ENG-ME-577; Prairie Island Characterization of Zebra Mussel Transport In Pump Intake Structure; Revision 0
AR CAP 037299; Zebra Mussel Process Not Effective In Eliminating the Zebra Mussels

1RST Post-Maintenance and Surveillance Testing

121 motor driven cooling water pump PMT

WO 03000176; 121 Motor Driven Cooling Water Pump Has a Leaking O-Ring on the Pump Shaft
Operating Logs for April 13, 2004
SP 1106C; 121 Cooling Water Pump Quarterly Test; Revision 22

12 DDCLP PMT

WO 0309990; P3002-2-12 DDCLP Annual Inspection
SP 1106A; 12 Diesel Cooling Water Pump Monthly Test; Revision 62
AR CAP 036292; 12 and 22 DDCLP jacket Cooler Outlet Valve Stroke 0.335 Inches Instead of 0.375 Inches

D2 Diesel Generator PMT

WO 0311194; SP 1307; D2 Diesel Generator 6 Month Fast Start; dated May 3, 2004
WO 0405702; Perform Mechanical Troubleshooting on D2
WO 0405705; Perform Additional PMT on D2 per SP 1307
Operating Log Entries for May 2 through May 5, 2004
AR CAP 036487; Problems Encountered on D2 During SP 1307
AR CAP 036492; Documentation of Common Mode Failure/Cause Evaluation for D1
AR CAP 036512; Additional PMT Required for D2 After Governor Bleed and Compensating Adjustments

11 Auxiliary Feedwater Pump PMT

WO 200092; 11 Turbine Driven Auxiliary Feedwater Pump Low Discharge Pressure Trip Pressure Switch Replacement
SP 1234A; 11 Auxiliary Feedwater Pump Suction and Discharge Pressure Switch Calibration

D5 Piston and Cylinder Liner Replacement

WO 0406189; D5 Diesel Generator PMT and Run In
Operating Logs for June 7 through June 9, 2004
AR CAP 037020;D5 E2 Underpressure Regulator Found Installed Backwards During WO 0406002

Surveillance Testing

SP 2334; D5 Diesel Generator 18 Month 24 Hour Load Test; Revision 9
AR CAP 036183; D5 Diesel Generator Bearing Vibration Alarms During 24 Hour Load Test
AR CAP 036170; 21 D5 Fuel Oil Storage Tank Transfer Pump Pumping Inadequately
SP 1106A; 12 Diesel Cooling Water Pump Monthly Test; Revision 62
SP 2089B; Train B Residual Heat Removal Pumps and Suction Valves from the Refueling Water Storage Tank Quarterly Test; Revision 5
AR CAP 037312; Control Damper 34180 Had Dual Indication During SP 1112
SP 1335; D2 Diesel Generator 18 Month 24 Hour Load Test; Revision 8
AR CAP 037141; Control Valve 31411 Opening Time Faster Than Reference Range on First Cycle During SP 1155B
SP 2295; D5 Diesel Generator 6 Month Fast Start Test; Revision 27
AR CAP 037021; 21 D5 Fuel Oil Transfer Pump Lost Prime Twice in the Past 2 Months

1R01 Adverse Weather

Hot Weather Preparations

Test Procedure 1636; Summer Plant Operation; Revision 16
Design Basis Document TOP-05; Hazards; Revision 2W
Operating Procedure C37.5; Screenhouse Normal Ventilation; Revision 7
Operating Procedure C37.5-1; Screenhouse Normal Ventilation; Revision 5W
Operating Procedure C37.8; Screenhouse Safeguard Equipment Cooling; 7
Operating Procedure C37.8-1; Screenhouse Safeguard Ventilation System; Revision 5W
Maintenance Rule System Specific Basis Document for the AT, ST, and ZR systems
Control Room Operating Logs for April 16 through April 19, 2004
AR CAP 032309; 13 Condensate Pump High Stator Temperature Alarm
AR CAP 032290; 13 Condensate Pump Operation In Limited Stator Life Range
AR CAP 032119; 13 Condensate Pump High Stator Temperature Alarm
AR CAP 031950; Received Unexpected Annunciator 47009-0304, 13 Condensate Pump High Stator Temperature Alarm
AR CAP 036149; Ineffective Corrective Actions to Prevent Recurrence of Condensate Stator Alarms
AR CAP 036245; Added Temporary Cooling to Unit 1 Condensate Pit

Tornado and High Winds

SP 1039; Tornado Hazard Monthly Site Inspection; Revision 7
Abnormal Procedure AB-2; Tornado/Severe Thunderstorm; Revision 20
Design Basis Document TOP-05; Hazards; Revision 2W
Maintenance Rule System Specific Basis Document for the AT, DG, ST, and SY systems
Engineering Calculation ENG-CS-233; Tornado Missile Evaluation; Bases for Requirements in Procedure SP 1039; Revision 0
AR CAP 031196; Found Two Dumpsters In Front of Plant Screenhouse Inadequately Secured
AR CAP 036060; Tornado Hazard per SP 1039
AR CAP 036061; Tornado Hazard per SP 1039
AR CAP 036622; Missile Concerns in the Substation
AR CAP 036702; CT11 Transformer Oil Sump Grating May Be a Tornado Missile Hazard
AR CAP 037384; SP 1039 Did Not Catch Potential Missile Hazards in the Switchyard
AR CE 003048; Found Two Dumpsters in Front of Plant Screenhouse Inadequately Secured
Other (OTH) 032447; Missile Concerns In the Substation

1R04 Equipment Alignment

System Pre-start Checklist C28-2; Auxiliary Feedwater System Unit 1; Revision 43
Integrated Checklist C1.1.20.7-1; D1 Diesel Generator Valve Status; Revision 20
Integrated Checklist C1.1.20.7-2; D1 Diesel Generator Auxiliaries and Room Cooling Local Panels; Revision 9

Integrated Checklist C1.1.20.7-3; Diesel Generator D1 Main Control Room Switch and Indicating Light Status; Revision 14
Integrated Checklist C1.1.20.7-4; D1 Diesel Generator Circuit Breakers and Panel Switches; Revision 12
AR CAP 035496; Configuration Control Issue and Minor Design Deficiency with the 121/122/123 SAC
CE 004778; Configuration Control Issue and Minor Design Deficiency with the 121/122/123 SAC
Integrated Checklist C1.1.20.7-13; D6 Diesel Generator Valve Status; Revision 12
Integrated Checklist C1.1.20.7-14; D6 Diesel Generator Auxiliaries and Local Panels Switches; Revision 8
Integrated Checklist C1.1.20.7-15; D6 Diesel Generator Main Control Room Switch and Indicating Status Lights; Revision 6
Integrated Checklist C1.1.20.7-16; D6 Diesel Generator Circuit Breakers and Panel Switches; Revision 8
System Pre-start Checklist C37.11-1; Chilled Water Safeguards System; Revision 14
NF-39603-3; Flow Diagram Lab & Service Area A/C & Chilled Water Safeguard System; Revision AJ

1R05 Fire Protection

Quarterly Fire Area Walkdowns

Plant Safety Procedure F5, Appendix F, Revision 19; Fire Hazard Analysis for Fire Areas; 59, 73, 102, 118, 114, 128, 20 and 80.
IPEEE NSPLMI-96001, Appendix B; Internal Fires Analysis; Revision 2
AR CAP 035371; Parts Usage Documentation Missing from WO 0300823
CE 004176; Parts Usage Documentation Missing from WO 0300823

Annual Fire Drill Observation

Operational Quality Assurance Plan; Appendix C; Revision 25
AR CAP 036803; Review Criteria for Procedure F5, Appendix J
Self Assessment 032542; Review Criteria for Procedure F5, Appendix J
CE 005304; Review Criteria for Procedure F5, Appendix J
Plant Safety Procedure F5, Appendix F, Revision 19; Fire Hazard Analysis for Fire Area 28
Plant Safety Procedure F5, Appendix A, Revision 11; Fire Strategies Zone 58
Plant Safety Procedure F5, Appendix J, Revision 10; Fire Drills

1R06 Flood Protection Measures (Internal)

NSPLMI-94001; Prairie Island Nuclear Generating Plant Individual Plant Examination; Revision 0
Design Basis Document TOP-05; Design Bases Document for in Hazards; Revision 2W
PINGP Procedure H36; Plant Flooding; Revision 0
PINGP Procedure C35 AOP5; Cooling Water Leakage Outside of Containment; Revision 6

Administrative Work Instruction 5AWI 8.9.0; Internal Flooding Drainage Control; Revision 1
Prairie Island Response to Generic Letter 89-13; dated July 24, 1989
PINGP Procedure H45; Pipe Thinning Inspection Program; Revision 0
Engineering Design, Fabrication, and Installation Summary for Erosion/Corrosion Monitoring; Section 2.2.7; Revision 0
Prairie Island Units 1 and 2 Microbiological Influenced Corrosion Report; 1995 To 1999 Summary
AR CAP 036734; 84 Inch Circulating Water Expansion Joint Has Stress Cracks

1R08 Inservice Inspection Activities

Report 97-0165; Prairie Island Unit 1, 45° and 60° UT Report Steam Generator No. 12; November 21, 1997
Report 2002U081; Tubesheet-to-head Steam Generator No. 12 weld W-A; November 28, 2002
Report 2003U003; Tubesheet-to-Head Steam Generator No. 21 weld W-A; September 15, 2003
Report 2000U157; Tubesheet-to-Head Steam Generator No. 21 weld W-A; May 20, 2000
CAP 026715; Missed Exam on 12 Steam Generator During the Unit 1 1999, Refueling Outage; November 25, 2002
CAP 026755; Missed Exam on 21 Steam Generator During the Unit 2 2002, Refueling Outage; November 26, 2002
SAWI 14.6.0; ASME Section XI Inservice Inspection and Pressure Testing; Revision 2

1R11 Licensed Operator Requalification Program

Simulator Evaluation Guide P9160S-001 ATT.SQ-46, Revision 0
5AWI 3.15.0; Plant Operation; Revision 15

1R12 Maintenance Rule Implementation

SP 1112; Steam Exclusion Monthly Damper Test; Revision 44
Design Basis Document TOP-05; Design Bases Document for in Hazards; Revision 2W
Maintenance Rule Evaluation (MRE) 000190; Control Damper (CD) 34187 Didn't Close
MRE 000248; CD 34177 Found Closed During SP 1112
MRE 000266; 47022-0103 Auxiliary Building Steam Exclusion Actuated
MRE 000268; Common Failure on Steam Exclusion Damper Resulting In An Unplanned Technical Requirements Manual Limiting Condition of Operation Entry
MRE 000272; Steam Exclusion Damper CD 34187 Inoperable
MRE 000291; CD 34201 Steam Exclusion Damper Does Not Mate Properly When Closed
PINGP Maintenance Rule Scope Determination and Performance Criteria
Maintenance Rule System Specific Basis Document; Steam Exclusion; Revision 8
AR CAP 036015; Gaps Found Between Closed Auxiliary Building Steam Exclusion Damper Vanes

AR CAP 036456; During SP 1112CD 34180 Did Not Close and Auxiliary Building Train A Did Not Stay Actuated
AR CAP 036560; Steam Exclusion Damper Does Not Mate Properly When Closed
AR CAP 036562; CD 34191 and CD 34192 Rubber Seating Surfaces Looked Aged

1R13 Maintenance Risk Assessments and Emergent Work Control

RYBT Voluntary Limiting Condition for Operation Plan; April 2, 2004
Unit 1 and Unit 2 Configuration Risk Assessment for May 18, 2004
Unit 1 and Unit 2 Configuration Risk Assessment for June 8, 2004
Unit 1 and Unit 2 Configuration Risk Assessment for June 15, 2004
Unit 1 and Unit 2 Configuration Risk Assessment for June 28, 2004

1R14 Nonroutine Evolutions

PINGP Operating Procedure 2C4 AOP1; Reactor Coolant Leak; Revision 10
PINGP Operating Procedure 2C12.1 AOP3; Loss of Letdown Flow to the VCT; Revision 0
Alarm Response Procedure C47512-0507; Pressurizer Level Deviation; Revision 42
Alarm Response Procedure C47515-0406; 21 Reactor Coolant Pump Seal Leakoff Low Flow; Revision 38
Alarm Response Procedure C47515-0508; Low Pressure Letdown Line High Flow or High Pressure; Revision 38
Alarm Response Procedure C47515-0509; Regenerative Heat Exchanger Line High Temperature; Revision 38
Alarm Response Procedure C47515-0608; Letdown Relief Line to Pressurizer Relief Tank High Temperature; Revision 38
Unit 2 Operating Logs for June 15, 2004
AR CAP 037140; Step Not Completed On Work Order 0405228
AR CAP 037136; Reactivity/Power Changes Following the Failure of the 22 Charging Pump

1R15 Operability Evaluations

AR CAP 036910; During SP 1112, CD-34199 Did Not Mate Fully
AR CAP 036911; During SP 1112, CD-34201 Dampers Closed Fully but Left a 1/16 Inch Gap
AR CAP 036015; Gaps Found In Between Closed Auxiliary Building Steam Exclusion Damper Vanes
CE 004992; Gaps Found In Between Closed Auxiliary Building Steam Exclusion Damper Vanes
AR CAP 036410; Temperature Switch 17936 Found Inoperable
OPR 000489; Temperature Switch 17936 Found Inoperable
AR CAP 036045; 121 Control Room Air Handler
AR CAP 036556; 121 Control Room Air Handler Fan Tripped
ACE 008837; 121 Control Room Air Handler Fan Tripped
AR CAP 036284; D5 Thermostatic Elements Pre-installation Test Results Out of Tolerance

OPR 000486; D5 Thermostatic Elements Pre-installation Test Results Out of Tolerance
TS 3.8.1; AC Sources-Operating; Amendment No. 149
AR CAP 037020; D5 E2 Underpressure Regulator Found Installed Backwards During WO 0406002
AR CAP 037028; Documentation of Under Pressure Regulator Orientation on D5/D6 Diesel Generators
AR CAP 037057; D5 Engine 2 Boroscope Examination Results
Attachment to AR CAP 037057; Review of the Susceptibility of D6 Emergency Diesel Generator
OPR 000496; D5 Crankcase Pressure and Cylinder Temperature Issues
AR CAP 036609; D5 Engine 2 Observed High Crankcase Pressure and Oil Leakage
AR CAP 037094; Operations Failed to Clearly Document the Status of D6 with D5 inoperable
Equipment/System Problem Investigation for D5 Diesel; June 8, 2004
OPR 000497; Leakby of Unit 2 Chemical and Volume Control System Isolation Valves Results in a 3 to 5 Gallon per Minute Reactor Coolant System Leak and Relief Lift
AR CAP 037135; Leakby of Unit 2 Chemical and Volume Control System Isolation Valves Results in a 3 to 5 Gallon per Minute Reactor Coolant System Leak and Relief Lift
SP 2072; Local Leakage Rate Test of Containment Penetrations; Revision 14

1R16 OWAs

Prairie Island Operator Workarounds; June 11, 2004
Operator Workaround Aggregate Impact; June 11, 2004

1EP6 Drill Evaluation

PINGP Emergency Plan Drill; May 5, 2004; Revision 0
PINGP EP Drill/Exercise Critique Data; May 6, 2004
AR CAP 036548; Recurring Issue on Control of Outplant Operators During E-Plan Events
AR CAP 036558; No Maximum Capacity Signs or Checklists Are Installed on Tornado Shelter Area
AR CAP 036557; Radiation Protection Short On Resources to Support Operations Support Center
AR CAP 036561; Operations Needs a Supervisor for the Operations Support Center During Emergency
AR CAP 036564; Declaration Time for Classification During Drill Not Entered by Emergency Manager
AR CAP 036565; Incorrect Information Transmitted to the Emergency Manager During the Emergency Preparedness Drill
AR CAP 036566; Emergency Off-site Facility Technical Support Personnel Not Aware of Their Current Severe Accident Mitigation Guidelines Qualifications
AR CAP Improper Protective Action Recommendation (PAR) Formulated and Improper PAR Notification During May Drill

AR CAP 036578; Alert Notification During May 5, 2004, Emergency Preparedness Drill Was Not Successfully Completed
AR CAP 036624; Emergency Plan Drill and Exercise Critiques

2OS2 ALARA Planning and Controls

5AWI 10.1.0; Radiation Protection Program; Revision 5
5AWI 10.1.1; ALARA Plan; Revision 1
CAP033408; Locked High Radiation Area Not Barricaded or Posted; dated October 9, 2003
CAP033902; Area Changed from Clean Area to Contaminated Area; dated November 6, 2003
CAP034316; ALARA Committee Did Not Meet the First Two Quarters of 2003; dated December 3, 2003
CAP036570; Nozzle Dams Not Decontaminated from Unit 2 Outage; dated May 7, 2003
CAP036662; HRA/LHRA Briefing for Entry Not Documented on Form 1470; dated May 13, 2004
CAP036692; Items Need Corrections for RAM Tagging; dated May 14, 2004;
CAP036781; Ventilation Misaligned for Ducting from Drying Rack to PAC Filter
PINGP 2004-SGR Outage Containment Scaffold ALARA Plan; Revision 0
PINGP 2004-SGR Outage Equipment Hatch ALARA Plan; Revision 0
PINGP 2004-SGR Outage Containment Structural Mods ALARA Plan; Revision 0
PINGP 2004-SGR Outage Fire Watch-Confined Space Attendant ALARA Plan; Revision 0
PINGP 2004-SGR Outage QC FME NDE ALARA Plan; Revision 0
PINGP 2004-SGR Outage Primary and Secondary Side Water Level Control Plan; Revision 0
PINGP 2004-SGR Outage Radiation Protection Staffing and Mobilization Plan; Revision 0
SA-032319; Snapshot Self-Assessment Report; dated May 14, 2004
PINGP 758; ALARA Review Checklist for Design Changes; Revision 3
PINGP 1287; ALARA Planning Checklist; Revision 3
RPIP [Radiation Protection Implementing Procedures] 1004; Radiation Protection ALARA Program; Revision 5
RPIP 1121; RWP Issue; Revision 20
RPIP 1160; ALARA Reviews; Revision 5
Site ALARA Committee Meeting Minutes February 18, 2004
Site ALARA Committee Meeting Minutes March 10, 2004
Site ALARA Committee Meeting Minutes April 14, 2004

2PS3 Radiological Environmental Monitoring and Radioactive Material Control Programs

ACE 008835; REMP Downstream River Sample Showed Elevated Tritium Activity
AR CAP 024566; REMP Air Sampler P-4 had Approximately 45 Hours Lost Time Week
AR CAP 026787; REMP Air Sampler P-2 Found with No Flow
AR CAP 027688; REMP Air Sampler P-4 Indicated 16 Hours Less Than Expected
AR CAP 029623; REMP Shipment Delayed Due to Missing Label; April 10, 2003
AR CAP 20017964; REMP Air Sampler at P1 Found Running but No Air Flow; Weekly Sample Missed

TP 1676; Meteorological Instruments Calibration; Revision 8
TP 1677; Meteorological Instrumentation Monthly Test; Revision 14
2001 Annual Radiological Environmental Monitoring Report; May 15, 2002
Annual Review of MIDAS Meteorological Data 2002
NUPIC [Nuclear Utilities Procurement Issues Committee] Audit Number 17795; NUPIC Joint Audit of Environmental, Inc. Northbrook, IL; August 13, 2001
PINGP 1117; REMP Calibration/Maintenance Form, Air Samplers (P-1 to P-6); April 27, 2004
RPIP 1302; Unconditional Release of Materials; Revision 15
Nuclear Oversight Observation Report # 2003-002-6-021; Radiological Effluent and Environmental Monitoring Programs; June 9, 2003
QF-0406 (FP-PA-SA-03); Self-Assessment Report, Radiological Environmental Program (REMP); March 29, 2004

4OA1 Performance Indicator Verification

Calculated Performance Indicator Data for the Unit 1 and Unit 2 Safety System Unavailability of the Residual Heat Removal System for the 2nd Quarter 2003, 3rd Quarter 2003, 4th Quarter 2003, and the 1st Quarter 2004
Calculated Performance Indicator Data for the Unit 1 and Unit 2 Reactor Scrams with Loss of Normal Heat Removal for the 2nd Quarter 2003, 3rd Quarter 2003, 4th Quarter 2003, and the 1st Quarter 2004
Unit 1 Operating Logs from April 1, 2003 through March 31, 2004
Unit 2 Operating Logs from April 1, 2003 through March 31, 2004
Plant Procedure H33.2; Mitigating Systems Cornerstone Unavailability Performance Indicator Reporting Instructions; Revision 7
Plant Procedure H33.1; Performance Indicator Reporting Instructions; Revision 5
Plant Procedure H33; Performance Indicator Reporting; Revision 5

4OA2 Identification and Resolution of Problems

Semi-Annual Trend Review

NRC Problem Identification and Resolution Inspection Report No. 05000282/2003007 (DRP); 05000306/2003007 (DRP); October 16, 2003
Change Management Plan - Trending Program Improvements; July 2002
Prairie Island Corrective Action Program Performance Indicators; May 2004
Top 10 Equipment Issues; June 23, 2004
Repeat Maintenance Reports; January, February, March, and April 2004
Equipment Health Status - Unit 1 and Unit 2; June 21, 2004
Maintenance Rule Status Chart; June 21, 2004
AR CAP 037286; Inadequate Closeout of Corrective Actions
AR CAP 037287; Implementation of the Site Trending Program is Less Than Adequate

4OA5 Other Activities

Closure of URI 05000282/2004002-01; 05000306/2004002-01

NSP-04-73; Letter from Westinghouse Electric Company to Nuclear Management Company, Response to Safety Injection Motor Questions; dated April 16, 2004
AR CAP 035339; Use of an SI Pump for Reactor Makeup (Appendix R)

Closure of UR 05000282/2000013-04; 05000306/2000013-04

Calculation Number ENG-ME-404; Loss of Off Site Power w/One CL Pump; Revision 1
CAP018907; Review and Document Site Position of Single Failure for External Events Is Outside of Design Basis; dated March 27, 2002
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
L. B. Marsh (NRR) Memorandum to G. E. Grant (DRP - Region III); Prairie Island Nuclear Generating Plant, Unit 2 - Response to TIA 2001-10, Design Basis Assumptions for Ability of Prairie Island, Unit 2, Emergency Diesel Generators to Meet Single Failure Criteria for External Events; (TAC No. MB2953); dated September 4, 2003

Temporary Instruction 2515/154

Failed Fuel Pin Basket Inventory as of May 11, 2004
Consolidated Rod Storage Container Inventory as of May 11, 2004
PINGP Current New Fuel Storage Map; Cycle 3
PINGP Spent Fuel Storage Map; Cycle 3
SP 1170; Special Nuclear Material Inventory; Revision 24; dated April 29, 2004
SP 1170; Special Nuclear Material Inventory; Revision 0; dated April 19, 1977
Maintenance Procedure D5.1; Spent Fuel Pit Handling Operations; Revision 32
Maintenance Procedure D5.1; Spent Fuel Pit Handling Operations; Revision 0
Administrative work Instruction 5AWI 12.1.0; Special Nuclear Material Control; Revision 8
Administrative work Instruction 5AWI 12.1.0; Special Nuclear Material Control; Revision 0
Administrative Control Directive 5ACD 12.1; Nuclear Fuel Control; Revision 0; dated May 15, 1979
Section Work Instruction SWI O-41; Duties and Responsibilities of Fuel Handling Personnel; Revision 11
Section Work Instruction SWI O-41; Duties and Responsibilities of Fuel Handling Personnel; Revision 0

TI 2515/156 Offsite Power System Operational Readiness

AR Operating Experience (OE) 028080; Evaluate INPO [Institute of Nuclear Power Operations] SEN [Significant Event Notification] 242 - Loss of Grid Event, August 14, 2003
AR OE 028081; Evaluate INPO SEN 242 - Loss of Grid Event, August 14, 2003

AR OE 028082; Evaluate INPO SEN 242 - Loss of Grid Event, August 14, 2003
AR CAP 030207; Electrical Grid Disturbance Caused Unexpected Sequencer Alarms
AR CAP 032118; Communication from Xcel Energy Not Timely for Northeast United States Grid Failure
AR CAP 035238; Large Electrical Disturbance on Grid Caused Multiple Control Room Alarms
AR CA 006716; Communication from Xcel Energy Not Timely for Northeast United States Grid Failure
SP 1295; D1 Diesel Generator 6 Month Fast Start Test; Revision 32
PINGP Maintenance Rule Risk Significant Equipment List
Maintenance Rule System Specific Basis Document for the AT, DG, ST, and SY Systems
Bus Voltage Tren for Buses 25 and 26 From 1996 Loss of Offsite Power Event
DBD TOP-16; Electrical Design Issues Topic; Revision 1W
Engineering Design, Fabrication, and Installation Summary for Undervoltage/Degraded Voltage Analysis; Section 2.3.13; Revision 0W
PINGP Operating Procedure C20.3; Electrical Power System Analysis; Revision 10
PINGP Operating Procedure C20.3 AOP1; Evaluating System Operating Conditions When Security Analysis is Out-of -Service; Revision 5

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
ALARA	As Low As Is Reasonably Achievable
AR	Action Request
ASME	American Society of Mechanical Engineers
AT	Auxiliary and Standby Transformer System
CAP	Corrective Action Program
CE	Condition Evaluation
CFR	Code of Federal Regulations
DDCLP	Diesel Driven Cooling Water Pump
DG	Diesel Generators
GL	Generic Letter
HX	Heat Exchanger
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination of External Events
LER	Licensee Event Report
LOOP	Loss of Offsite Power
NCV	Non-Cited Violation
NRC	U.S. Nuclear Regulatory Commission
NRR	(Office of) Nuclear Reactor Regulation
NUPIC	Nuclear Utilities Procurement Issues Committee
ODCM	Offsite Dose Calculation Manual
OPR	Operability Recommendation
PINGP	Prairie Island Nuclear Generating Plant
PMT	Post-Maintenance Test
RCS	Reactor Coolant System
REMP	Radiological Environmental Monitoring Program
RPIP	Radiation Protection Implementing Procedures
SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection
SNM	Special Nuclear Material
SP	Surveillance Procedure
ST	Cooling Tower Substation System
SY	Plant Substation System
TIA	Task Interface Agreement
TLD	Thermoluminescence Dosimeter
TS	Technical Specifications
URI	Unresolved Item
USAR	Updated Safety Analysis Report
UT	Ultrasonic Testing
WO	Work Order
ZR	Screenhouse Safeguards Ventilation System