UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

February 8, 2005

Gregg R. Overbeck, Senior Vice
President, Nuclear
Arizona Public Service Company
P.O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: PALO VERDE NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000528/2004005, 05000529/2004005; AND 05000530/2004005

Dear Mr. Overbeck:

On December 31, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility. The enclosed integrated report documents the inspection findings, which were discussed on January 7, 2005, with you and other members of your staff.

The inspection examined activities conducted under your licenses as they relate to safety and 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.

This report documents four NRC identified and three self-revealing findings of very low safety significance (Green). These findings were determined to involve violations of NRC requirements; however, because of the very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest these noncited violations, 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 copies to the Regional Administrator, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be made 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/

Scott C. Schwind, Chief
Project Branch D
Division of Reactor Projects

Dockets: 50-528
50-529
50-530

Licenses: NPF-41
NPF-51
NPF-74

Enclosure:
NRC Inspection Report 05000528/2004005, 05000529/2004005, and 05000530/2004005
w/Attachment: Supplemental Information

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SISP Review Completed: __SCS ADAMS: / Yes ☐ No Initials: _SCS__
/ Publicly Available ☐ Non-Publicly Available ☐ Sensitive / Non-Sensitive

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RIV:RI:DRP/D	RI:DRP/D	RI:DRP/D	SPE:DRP/D	SPE:DRP/D
JFMelfi	GGWarnick	NLSalgado	GEWerner	MPShannon
SCS for	**SCS for**	**SCS for**	**SCS for**	**/RA/**
2/8/05	2/8/05	2/8/05	2/8/05	2/7/05

C:DRS/PSB	C:DRS/EMB	C:DRS/PEB	C:DRP/D	
JAClark	ATGody	LJSmith	SCSchwind	
/RA/	**/RA/**	**/RA/**	**/RA/**	
2/7/05	2/3/05	2/3/05	2/2/05	

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528, 50-529, 50-530
Licenses:	DPR-41, NPF-51, NPF-74
Report:	05000528/2004005, 05000529/2004005, 05000530/2004005
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Tonopah, Arizona
Dates:	October 1 through December 31, 2004
Inspectors:	B. Baca, Health Physicist L. Ellershaw, Senior Reactor Inspector, Engineering Branch C. Johnson, Senior Reactor Inspector, Engineering Branch J. Melfi, Resident Inspector, Project Branch D C. Osterholtz, Senior Resident Inspector, Project Branch C N. Salgado, Senior Resident Inspector, Project Branch D J. Taylor, Resident Inspector, Project Branch A C. Stancil, Project Engineer, Project Branch TSS G. Warnick, Senior Resident Inspector, Project Branch D G. Werner, Senior Project Engineer, Project Branch D
Approved By:	Scott C. Schwind, Chief, Project Branch D Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000528/2004005, 05000529/2004005; 05000530/2004005; 10/01/04 - 12/31/04; Palo Verde Nuclear Generating Station, Units 1, 2 and 3; Integrated Resident and Regional Report; Maintenance Effectiveness, Operability Evaluations, Refueling and Outage Activities, Surveillance Testing, ALARA Planning and Controls, and Other Activities.

This report covered a 3-month period of inspection by resident inspectors and inspection staff from the regional office. The inspection identified seven findings. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management's 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. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Criterion V, "Instructions, Procedures, and Drawings," for not following the timeliness requirements noted in Procedure 40DP-9OP26, "Operability Determination," following the identification of a nonconforming condition associated with pressurizer heater sleeve modification tolerances. Procedure 40DP-9OP26 required that the shift manager or shift technical advisor be immediately notified of indications of a potential non-conformances. A condition report/disposition request was initiated on November 9, 2004, but neither the shift manager, nor the shift technical advisor were notified until Wednesday, November 10, 2004. This issue also had problem identification and resolution crosscutting aspects associated with engineering personnel not informing the control room in a timely manner and is similar to issues noted in adverse Condition Report/Disposition Requests 2733983 and 2734037, issued on August 26, 2004. The issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2754848.

  This finding is greater than minor since the failure to follow the operability determination process, if left uncorrected, would become a more significant safety concern. Using the Phase 1 Worksheet in Manual Chapter 0609, "Significance Determination Process," the finding is determined to have very low safety significance because it only affected the initiating events cornerstone and did not result in actual degradation of the reactor coolant system boundary (Section 1R15).

Cornerstone: Barrier Integrity

- Green. The inspectors identified a noncited violation of Technical Specification Surveillance Requirement 3.6.3.3 for failure to perform the required position verification for vent and drain valves associated with eight safety injection system penetrations per unit. The issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2753335.

  This finding is greater than minor since it is associated with the configuration control attribute of the barrier integrity cornerstone and affects the cornerstone objective to provide reasonable assurance that the containment physical design barrier is preserved to protect the public from radio nuclide releases caused by accidents or events. Using the Phase 1 Worksheet in Manual Chapter 0609, "Significance Determination Process," the finding is determined to have very low safety significance because it only affected the barrier integrity cornerstone, all the valves were found closed, and did not result in an actual open pathway out of the reactor containment (Section 1R22).

- Green. The inspectors identified a self-revealing noncited violation of Technical Specification 3.9.2 occurred while performing core alterations with less than the required number of startup range monitors. The licensee did not identify that startup monitor Channel 2 was failed low through troubleshooting activities prior to commencing core reload. The licensee only determined that startup monitor Channel 2 was inoperable after core alterations had commenced. The issue was entered into the licensee's corrective action program as Condition Report/Disposition Requests 2654704 and 2654642.

  The finding is greater than minor because it is associated with the configuration control attribute of the barrier integrity cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radio nuclide releases caused by accidents or events. Using Manual Chapter 0609, Appendix G, "Shutdown Operations Significance Determination Process," this finding is determined to have very low safety significance because the event did not constitute a loss of control and did not represent a finding requiring quantitative assessment. The finding did not increase the likelihood of loss or cause a degradation in the ability to restore decay heat removal, reactor coolant system inventory, offsite power, alternate core cooling, or containment (Section 4OA3).

Cornerstone: Mitigating Systems

- Green. The inspectors identified a self-revealing noncited violation of Technical Specification 5.4.1.d for an inadequate fire protection program maintenance procedure used to replace underground fire protection post indicator valves. The procedure did not clearly indicate that the preassembled bolts (body to bonnet), as well as other bolts, were to be coated for corrosion protection. This allowed the bolts to corrode, causing failure of the valve and a degradation of the site yard fire main distribution piping and a loss of approximately 278,000 gallons of fire protection water. The issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2700170.

This finding is greater than minor because it is associated with the degraded fire protection attribute of the mitigating systems cornerstone and affected the cornerstone objective, which is to ensure the availability, reliability, and capability of systems that mitigate initiating events to prevent reactor accidents. Specifically, the site yard fire main distribution piping was degraded for 45 minutes. Using the Significance Determination Process Phase 1 Worksheet, the finding was determined to have a very low safety significance because it did not involve complete, long-term impairment of the fire protection system. Specifically, the required fire protection water inventory remained above the design reserve level, and the fire main was degraded less than 1 hour (Section 1R12).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for an inadequate procedure which resulted in a reactor coolant system level deviation during the reactor coolant system draindown to hot midloop conditions. Specifically, Procedure 40OP-9ZZ16, "RCS Drain Operations," Revision 45, was inadequate in that it did not provide reduced drain rates or increased hold points to minimize the excessive difference between actual and indicated reactor coolant system level caused by static head difference between the pressurizer/surge line and the reactor. The finding involved problem identification and resolution crosscutting aspects that contributed to the finding in that engineering documents were available that specified correct drain rates, but these drain rates were not referenced until NRC inspectors questioned the justification of the values allowed by the procedure. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2742525.

  The finding is greater than minor because it is associated with the equipment performance attribute of the mitigating systems cornerstone and affects the cornerstone objective of ensuring the reliability of systems that respond to initiating events. The inadequate procedure resulted in an actual indicated level transient while the reactor coolant system was being drained in reduced inventory conditions. Using Manual Chapter 0609, Appendix G, "Shutdown Operations Significance Determination Process," this finding is determined to have very low safety significance because the event did not constitute a loss of control and did not represent a finding requiring quantitative assessment. The finding did not increase the likelihood of loss or cause a degradation in the ability to restore decay heat removal, reactor coolant system inventory, offsite power, alternate core cooling, or containment (Section 1R20).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for failing to follow documented procedures when performing activities affecting quality. Administrative Procedure 40DP-90P26, “Operability Determination,” was not followed when performing an operability assessment of emergency diesel generator fuel oil transfer pump Train A following identification of water in the electrical conduit and junction boxes associated with the power supply to the pump. Specifically, licensee personnel failed to consider water intrusion into the electrical conduit for emergency diesel generator fuel oil transfer pump Train A as a condition that could affect the ability of the emergency diesel generator to perform its specified function, and consequently, declared emergency diesel generator Train A operable. The finding involved problem identification and resolution crosscutting aspects in that licensee personnel failed to recognize water intrusion into the conduit box as a potential deficiency that could impact emergency diesel generator operability until prompted by the inspectors. This issue was entered into the licensee’s corrective action program as Condition Report/Disposition Request 2763326.

  The finding is greater than minor since it is associated with the equipment performance attribute of the mitigating system cornerstone and affects the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events. Using the Significance Determination Process Phase 1 Worksheet, this finding is determined to have very low safety significance because it only affects the mitigating system cornerstone and was a deficiency that did not result in the actual loss of the safety function of the emergency diesel generator (Section 1R22).

Cornerstone: Occupational Radiation Safety

- Green. The inspectors reviewed a self-revealing noncited violation of Technical Specification 5.7.1.b because a radiation worker could not hear the electronic dosimeter alarm. Specifically, on September 30, 2003, a radiation worker, in a high radiation area, could not hear the electronic dosimeter alarm for approximately thirty minutes. The individual did not respond to the alarm until after entering another area with lower ambient noise. The licensee determined that the individual had a hearing deficiency. This issue was entered into the licensee’s corrective action program as Condition Report/Disposition Request 2689876.

  The failure to provide an effective alarming dosimeter to a worker entering a high radiation area is a performance deficiency. This finding is greater than minor because it is associated with the occupational radiation safety program and process attribute and affected the cornerstone objective because the failure to hear an electronic dosimeter alarm could increase personnel dose. Using the occupational radiation safety significance determination process, the inspectors determined that the finding was of very low safety significance because it did not involve the following: (1) ALARA planning and controls, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess dose (Section 2OS2).

B. Licensee-Identified Violations

Violations of very low safety significance which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program (Section 4OA7).

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at essentially full power until December 6, 2004 when power was reduced to 91 percent to remove Condensate Pump C out of service to repair a small leak on a mini-flow recirculation line. Following repairs the unit was returned to full power on December 7, 2004. On December 16, 2004. a problem with both core operating limit supervisory systems (COLSS) forced a downpower to approximately 38 percent. The core monitoring computer (CMC) COLSS was restored and Unit 1 returned to full power on December 17, and remained there for the duration of this inspection period.

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

Unit 3 operated at essentially full power until October 2, 2004, when the reactor was shut down for the eleventh refueling outage. The outage was completed on December 7, and the unit was returned to essentially full power on December 12, and remained there for the duration of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Seasonal Susceptibilities

a. Inspection Scope

The inspectors completed a review of the licensee's readiness of seasonal susceptibilities involving extreme temperatures. The inspectors (1) reviewed plant procedures, the Updated Final Safety Analysis Report (UFSAR), and Technical Specifications to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the below listed systems to ensure that adverse weather protection features were sufficient to support operability including the ability to perform safe shutdown functions; (3) evaluated operator staffing levels to ensure the licensee would maintain the readiness of essential systems required by plant procedures; and (4) reviewed the corrective action program (CAP) to determine if the licensee identified and corrected problems related to adverse weather conditions.

- November 30, 2004, Unit 1, normal chilled water system
- November 30, 2004, Unit 2, normal chilled water system
- November 31, 2004, Units 1, 2, and 3, review of preventive maintenance program for refueling water temperature element.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors completed a review of the licensee's readiness for impending adverse weather such as severe thunderstorms, tornado warnings, and high winds. The inspectors (1) reviewed plant procedures, the Updated Safety Analysis Report, and Technical Specifications to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems and (2) reviewed plant modifications, procedure revisions, and operator work arounds to determine if recent facility changes challenged plant operation.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

Partial System Walkdowns

a. Inspection Scope

The inspectors (1) walked down portions of the two below listed risk important systems and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned and (2) compared deficiencies identified during the walk down to the CAP to ensure problems were being identified and corrected.

- October 5, 2004, Unit 3, shutdown cooling system Train B during midloop operations

- October 25, 2004, Unit 3, emergency diesel generator (EDG) Train A while EDG Train B was out of service for maintenance

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

Routine Inspection

The inspectors walked down the six below listed plant areas to assess the material condition of active and passive fire protection features, their operational lineup, and their operational effectiveness. The inspectors (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features; and (7) reviewed the CAP to determine if the licensee identified and corrected fire protection problems.

- October 4, 2004, Unit 3, containment building, all accessible elevations
- October 26, 2004, Unit 2, main steam support structure, all accessible elevations
- November 17, 2004, Unit 3, condensate storage pump house and tunnel
- December 8, 2004, Unit 1, condensate storage pump house and tunnel
- December 8, 2004, Unit 2, condensate storage pump house and tunnel
- December 9, 2004, Unit 1, main steam support structure, all accessible elevations

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08, Temporary Instruction (TI) 2515/150)

Inspection Procedure 71111.08 requires a minimum sample size of four, one sample for each Section (Sections 02.01, 02.02, 02.03, and 02.04).

a. Inspection Scope

Performance of Nondestructive Examination Activities Other than Steam Generator Tube Inspections, Pressurized Water Reactor (PWR) Vessel Upper Head Penetrations Inspections, Boric Acid Control

The procedure requires the review of nondestructive examination activities consisting of two or three different types. The inspectors reviewed the records of three volumetric examinations and 15 visual examinations, and witnessed the performance of one surface and three volumetric examinations. This sample of 22 nondestructive examination activities is listed in the attachment.

For each of the nondestructive examination activities reviewed, the inspectors verified that the examinations were performed in accordance with site procedures and the applicable American Society of Mechanical Engineers (ASME) Code requirements.

During the review of each examination, the inspectors verified that appropriate nondestructive examination procedures were used; that examinations and conditions were as specified in the procedure; and that test instrumentation or equipment was properly calibrated and within the allowable calibration period. The inspectors also reviewed documentation to verify that indications revealed by the examinations were dispositioned in accordance with site procedures and the ASME Code specified acceptance standards. The inspectors verified the certifications of five nondestructive examination personnel observed performing examinations or identified during review of completed examination packages.

The inspection procedure required review of one or two examinations with recordable indications that were accepted for continued service, to ensure that the disposition was made in accordance with the ASME Code. During the previous outage there were several recordable indications that required evaluation. These indications were found in the control element drive mechanism (CEDM) during the reactor vessel head examinations. There were a total of 13 special interest indications. The licensee evaluated the indications in accordance with their site procedural requirements. These indications were further evaluated and re-examined using the eddy-current method from the outside diameter of the CEDMs. The inspectors also selected CEDM Penetration 30 and compared the nondestructive examination results from the previous outage to the current outage to determine if the indication had increased in size. There was no apparent increase noted. The inspectors reviewed and determined that the corrective action plans were appropriate.

The procedure required verification of one to three welds on Class 1 or 2 pressure boundary piping to ensure that the welding process and welding examinations were performed in accordance with the ASME Code. The inspectors reviewed one completed weld record (Work Order (WO) 2608319) of work performed during the current outage. Maintenance personnel welded a 16-inch pipe to a 24-inch x 16-inch reducer (feedwater to steam generator). Records indicated that welding was performed in accordance with site procedures and ASME Code requirements.

b. Findings

No findings of significance were identified.

The inspectors completed one sample.

PWR Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

The inspectors reviewed a total of 15 CEDM penetration records. This sample selection of 15 was above the 10 percent total number of CEDMs required by TI 2515/150, "Reactor Pressure Vessel Head And Vessel Head Penetration Nozzles." The inspectors observed the ultrasonic and eddy-current examinations of all 15 CEDM penetrations. The inspectors verified that activities performed on the vessel upper head penetrations were consistent with the requirements of NRC Order EA-03-009. The inspectors verified that the calibration of equipment used was performed in accordance with Westinghouse procedures. These nondestructive examination activities are listed in the attachment. The inspectors observed the ultrasonic and eddy-current examinations of CEDM Penetrations 80, 81, 95, and 96.

The inspectors reviewed the certification records for seven personnel performing the automated ultrasonic and eddy-current examinations and data analysis performed on the CEDMs.

There was no welding repairs ongoing or completed on the upper head penetrations during this inspection.

b. Findings

No findings of significance were identified.

The inspectors completed one sample.

Boric Acid Corrosion Control Inspection Activities (PWRs)

a. Inspection Scope

The inspection procedure required a review of one to three engineering evaluations performed for boric acid found on reactor coolant system (RCS) piping and components.

The inspectors reviewed one interim and one final disposition engineering evaluation performed for boric acid found on RCS piping and components during March 19-20, 2003, for Unit 3; and the current outage boric acid walkdown results. The inspectors determined that the licensee was identifying any boric acid during the walkdown and documenting the location for a final engineering disposition evaluation.

The procedure also required the review of one to three corrective actions performed for evidence of boric acid leaks identified.

The inspectors reviewed two condition report/deficiency reports (CRDRs) from the previous outage relating to (1) leakage found on Unit 3 Pressurizer Heater Sleeves A-1 and -15 and (2) during the boric acid walkdown in Unit 3, leakage was identified on one Hot-leg Pressure/Sampling Nozzle 3JRCBTE112HB. The inspectors determined that boric acid leaks identified were evaluated or corrected through the corrective action process.

b. Findings

No findings of significance were identified.

The inspectors completed one sample.

Steam Generator Tube Inspection Activities

b. Inspection Scope

The inspection procedure specified performance of an assessment of in-situ screening criteria to assure consistency between assumed nondestructive examination flaw sizing accuracy and data from the Electric Power Research Institute (EPRI) examination technique specification sheets. It further specified assessment of appropriateness of tubes selected for in-situ pressure testing, observation of in-situ pressure testing, and review of in-situ pressure test results.

At the time of this inspection, no conditions had been identified that warranted in-situ pressure testing. The inspectors did, however, review the Palo Verde Nuclear Generating Station, Unit 3, Degradation Assessment Report dated June 2004, and compared the in-situ test screening parameters to the guidelines contained in the EPRI document “In-Situ Pressure Test Guidelines,” Revision 2. This review determined that the screening parameters were consistent with the EPRI guidelines. The inspectors also noted that the licensee implemented a computer program with prescreening criteria that have a lower threshold than the aforementioned EPRI in-situ guidelines.

In addition, the inspectors reviewed both the licensee site-validated and qualified acquisition and analysis technique sheets used during this refueling outage; and the qualifying EPRI examination technique specification sheets to verify that the essential variables regarding flaw sizing accuracy, tubing, equipment, technique, and analysis had been identified and qualified through demonstration. The inspectors-reviewed acquisition technique and analysis technique sheets are identified in the attachment.

The inspection procedure specified comparing the estimated size and number of tube flaws detected during the current outage against the previous outage operational assessment predictions to assess the licensee's prediction capability. The inspectors compared the previous outage operational assessment predictions with the flaws identified thus far during the current steam generator tube inspection effort. The number of identified indications are lower than predicted in the eggcrate regions, but somewhat higher than predicted in the hot-leg ARC region (upper bundles from Eggcrate 7H to Vertical Support VS3. Licensee personnel believed that the chemical cleaning of the steam generators during Refueling Outage U3R10 increased detection capability resulting in higher numbers. The inspectors determined that the flaw degradation severity levels found, thus far, were well within the predicted expectations. The inspectors also reviewed tube plugging predictions and found that the number of tubes identified for plugging during this outage paralleled the predicted number (approximately 200 tubes total).

The inspection procedure specified confirmation that the steam generator tube eddy-current test scope and expansion criteria meet Technical Specification requirements, EPRI guidelines, and commitments made to the NRC.

The inspectors evaluated the recommended steam generator tube eddy-current test scope established by Technical Specification requirements, integration of information from the condition monitoring evaluation, the Unit 3 operational assessment evaluation, and the Unit 3 degradation assessment report. This data was compiled and documented in a section of the Unit 3 degradation assessment, "Assessment of Steam Generator Tube Degradation Mechanisms - Recommended SG Inspection, Testing, and Repair Scope - U3R11," dated June 2004. The inspectors compared the eddy-current test scope to the actual eddy-current test scope and found that the licensee had administratively expanded the scope considerably beyond the recommended scope as delineated in the degradation assessment. At the time of this inspection, Technical Specification scope expansion criteria had not been invoked.

The inspection procedure specified, if new degradation mechanisms were identified, verification that the licensee fully enveloped the problem in its analysis of extended conditions including operating concerns, and had taken appropriate corrective actions before plant startup. The eddy-current test results, to date, had not identified any new degradation mechanisms.

The inspection procedure required confirmation that the licensee inspected all areas of potential degradation, especially areas which were known to represent potential eddy-current test challenges (e.g., top-of-tubesheet, tube support plates, and U-bends). The inspectors confirmed that all known areas of potential degradation, were included in the scope of inspection and were being inspected.

The inspection procedure further required verification that repair processes being used were approved in the Technical Specifications. During this inspection, the inspectors observed the installation of several mechanically rolled plugs in the cold-leg side of Steam Generator 3-1. At the time of this inspection, it was estimated that a total of approximately 200 tubes would be plugged. The inspectors verified that this particular plugging operation was an NRC approved repair process.

The inspection procedure also required confirmation of adherence to the Technical Specification plugging limit, unless alternate repair criteria have been approved. The inspection procedure further required determination whether depth sizing repair criteria were being applied for indications other than wear or axial primary water stress corrosion cracking in dented tube support plate intersections. The inspectors determined that the Technical Specification plugging limits were being adhered to (i.e., 40 percent maximum through-wall indication). The inspectors also determined that the licensee had administratively established more conservative limits with respect to specific locations or defect types (e.g., plug any tube exhibiting = or > 20 percent through-wall indication in the cold-leg corners and batwing stay cylinder areas; plug any previously identified single volumetric indication that showed an increase in flaw size; plug any crack-like indication; and plug any tubes in which detectable wear was caused by possible loose parts). The inspectors also noted that the degradation assessment and inspection scope provided specific sizing information as it related to both outside and inside diameter axial and circumferential indications, including inside diameter axial indications at dent locations.

If steam generator leakage greater than 3 gallons per day was identified during operations or during postshutdown visual inspections of the tubesheet face, the inspection procedure required verification that the licensee had identified a reasonable cause based on inspection results and that corrective actions were taken or planned to address the cause for the leakage. The inspectors did not conduct any assessment because this condition did not exist.

The inspection procedure required confirmation that the eddy-current test probes and equipment were qualified for the expected types of tube degradation and an assessment of the site specific qualification of one or more techniques. The inspectors observed portions of eddy-current test performed on the following locations in Steam Generators 31 and 32: full length, U-bends, hot-leg square bends, and special interest locations. During these examinations, the inspectors verified that (1) the probes appropriate for identifying the expected types of indications were being used; (2) probe position location verification was performed; (3) calibration requirements were adhered to; and (4) probe travel speed was in accordance with procedural requirements. The inspectors performed an of site-specific qualifications of the techniques being used. These are identified in the attachment under the listing of Acquisition, Analysis, and Examination Technique Specification Sheets.

If loose parts or foreign material on the secondary side were identified, the inspection procedure specified confirmation that the licensee had taken or planned appropriate repairs of affected steam generator tubes, and that they inspected the secondary side to either remove the accessible foreign objects, or performed an evaluation of the potential effects of inaccessible object migration and tube fretting damage.

A loose part was identified in Steam Generator 32. Three tubes, which had no previous wear indications, exhibited wear of up to 25 percent. The tubes were peripherally located in the cold leg side of the top of tubesheet. The licensee implemented their foreign object search and retrieval program, and located the object, which turned out to be a 2-inch diameter, 5-inch long set screw that had backed out of the feedwater box. A comprehensive analysis and evaluation was performed, which addressed the following areas: feedwater box integrity, streaming flow through the empty set screw hole, loose part wear; and unit operability. Corrective actions included plugging and staking the affected and adjacent tubes in Steam Generator 32, and sister-tubes in identical locations in Steam Generator 33 as a precaution against a similar occurrence in that steam generator. While all actions had not yet been completed, the licensee had thoroughly documented the condition and actions taken or to be taken.

Finally, the inspection procedure specified review of one to five samples of eddy-current test data if questions arose regarding the adequacy of eddy-current test data analyses. The inspectors did not identify any results where eddy-current test data analyses adequacy was questionable.

The inspectors conducted a review of the licensee's actions resulting from issuance of Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections," issued August 30, 2004. The generic letter advised addressees that the NRC's interpretation of the Technical Specification requirements in conjunction with 10 CFR Part 50, Appendix B, raises questions as to whether certain licensee steam generator tube inspection practices ensure compliance with these requirements. Therefore, all holders of operating licenses for PWRs were required to submit a written response to the generic letter in which the requested information would be provided within 60 days of the date of the generic letter. Specifically, the generic letter requested that:

(1) Addressees submit a description of the tube inspections performed at their plants, including an assessment of whether these inspections ensure compliance with the Technical Specification requirements in conjunction with 10 CFR Part 50, Appendix B.

(2) Addressees who conclude they are not in compliance with the steam generator tube inspection requirements contained in their technical specification in conjunction with 10 CFR Part 50, Appendix B, propose plans for coming into compliance with these requirements.

(3) Addressees to submit a tube structural and leakage integrity safety assessment that addresses any differences between their practices and the NRC's position regarding the requirements of the technical specification in conjunction with 10 CFR Part 50, Appendix B. A safety assessment should be submitted for all areas of the tube required to be inspected by the Technical Specification where flaws have the potential to exist and inspection techniques capable of detecting

these flaws are not being used. This assessment should include an evaluation of whether the inspection practices rely on an acceptance standard different from the Technical Specification acceptance standards and whether the technical basis for these inspection practices constitutes a change to the “method of evaluation” (as defined in 10 CFR 50.59) for establishing the structural and leakage integrity of the tube-to-tubesheet joint.

The licensee’s response was submitted to the NRC via Letter 102-05171-CDM/TNW/GAM, dated October 28, 2004. The licensee determined that the Unit 2 program for the replacement steam generator tube inspections is consistent and in conformance with the NRC’s position identified in the generic letter and no corrective actions are required.

The licensee’s response with respect to Units 1 and 3 concluded that the inspection program meets or exceeds the NRC position with one exception. Units 1 and 3 steam generator tube inspection programs are not consistent with the NRC’s position with respect to inspections performed within the tubesheet. The response further stated that the proposed corrective action to establish conformance with the NRC position is to submit a Technical Specification amendment request consistent with the recommended changes in Generic Letter 2004-01 to limit the extent of the inspection in the tubesheet region where the tubes are expanded for the full depth of the tubesheet. The licensee committed to submit the Technical Specification changes no later than May 31, 2005. Further, the licensee provided a safety assessment based on information previously provided to the NRC in September 2002 and supplemented by test data and analyses performed in Westinghouse Report WCAP-16208, Revision 0, dated October 2004.

The licensee’s safety assessment for the Units 1 and 3 steam generators concluded that no safety or operability issues exist based on current inspections and integrity assessments, and that the current enhanced steam generator tube assessment approach is consistent with previous submittals to the NRC.

The licensee documented the nonconformance with the NRC position in the generic letter in their CAP in CRDR 2734928 dated September 2, 2004.

Finally, with respect to item (3) above, the licensee concluded that the analysis approach does not redefine the ASME Code pressure boundary and is not a change in the method of evaluation as defined in 10 CFR 50.59.

The inspectors reviewed generic letter and the licensee’s response, including the referenced documents, and determined that a minor violation of Criteria IX and XI in Appendix B of 10 CFR Part 50 had occurred (i.e., the Units 1 and 3 steam generator tube inspection programs are not consistent with the NRC’s position with respect to inspections performed within the tubesheet). This finding, after being evaluated in accordance with Section 3 in Appendix B of Manual Chapter 0612, was determined to be a minor violation.

b. Findings

No findings of significance were identified.

The inspectors completed one sample.

Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed selected inservice inspection related CRDRs issued during the current and past refueling outages. The review served to verify that the corrective action process was being correctly utilized to identify conditions adverse to quality and that those conditions were being adequately evaluated, corrected, and trended. The inspectors determined that the threshold for initiating CRDRs was low, thereby, capturing any deficiencies identified in the inservice inspection program. The inspectors also concluded that corrective actions were being appropriately addressed.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique.

- November 18, 2004, SES-0-10-D-00, “Loss of NAN-SO5/Dropped CEA”

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the below listed component and system maintenance activities to (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the Maintenance Rule, 10 CFR Part 50, Appendix B, and Technical Specifications.

- October 2004, Unit 3, inspection and maintenance on Safety Injection (SI) Tank 2A discharge check Valve 3PSIEV217 per Procedure 31MT-9ZZ17, “Borg-Warner Check Valve Disassembly and Assembly,” Revision 17

- October 2004, fire protection system maintenance

The inspectors completed two samples.

b. Findings

Introduction. A Green self-revealing noncited violation (NCV) of Technical Specification 5.4.1.d was identified regarding an inadequate fire protection program maintenance procedure for the site yard fire main distribution piping.

Description. On April 19, 2004, an underground fire main ruptured at Post Indicator Valve (PIV) -048. The rupture reduced pressure in the fire main, causing starting of all three fire pumps and spilling approximately 278,000 gallons of water, but was isolated without decreasing of fire water reserves below required limits in the fire water tanks.

The failure of the PIV was due to corrosion of the body-to-bonnet bolts. Maintenance personnel use Work Scope Library Documents 2429554 and 2415680 to control the work. These documents required the application of Bitumastic (a corrosion preventative) to all exposed fasteners. The work scope library, derived in part from American Water Works Association Standard C509-01, Section A.5.1, required all bolts to be checked for proper tightness and protected by the installer to prevent corrosion. The licensee failed to apply the Bitumastic coating to the exposed fasteners as required by the maintenance documents.

Review of the corrective actions for the failure indicated that other areas for improvement in treatment of all underground piping were being addressed. Condition report/deficiency reports have addressed improving the cathodic protection system; controlling associated vendor services; and establishing priorities and inspection programs for underground piping.

Analysis. The failure to coat the body-to-bonnet bolts was a performance deficiency. This finding was considered more than minor because it is associated with the degraded fire protection attribute of the mitigating systems cornerstone and affected the cornerstone objective, which is to ensure the availability, reliability, and capability of systems that mitigate initiating events to prevent reactor accidents.

Since fire suppression capabilities were maintained following this failure, the inspectors concluded that this finding did not represent a degradation of any fire protection defense-in-depth strategies. Therefore, the operating reactor safety significance determination process was used to evaluate the safety significance of this finding. The finding was determined to be of very low safety significance (Green) because it did not involve complete, long-term impairment of the fire protection system and the finding did not screen as risk significant due to external initiating events.

Enforcement. Technical Specification 5.4.1.d states, in part, that procedures shall be established, implemented, and maintained covering fire protection program implementation. Contrary to the above, on April 19, 2004, PIV -048 failed due to inadequate implementation of the installation procedure during maintenance. The failure of the valve was of very low safety significance and was entered into the CAP as CRDR 2700170. This violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000530/2004005-01, "Failure to Provide Adequate Maintenance Procedure."

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

a. Inspection Scope

Risk Assessment and Management of Risk

The inspectors reviewed the below listed assessment activities to verify (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and/or enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- November 16, 2004, Unit 2, management of Orange risk configuration during performance of Procedure 73ST-9AF02, "AFA-P01 - Inservice Test," Revision 30

- November 17, 2004, Unit 1, scheduled online outage for EDG, essential chilled water, essential cooling water, essential spray pond, and Containment Spray (CS) System Train A

- November 17, 2004, Unit 3, polar crane heavy load lift associated with performance of Procedure 31MT-9RC33, "Reactor Vessel Upper Guide Structure Removal and Installation," Revision 27

The inspectors completed three samples.

Emergent Work Control

The inspectors (1) verified that the licensee performed actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems and barrier integrity systems; (2) verified that emergent work-related activities such as troubleshooting, work planning/scheduling, establishing plant conditions, aligning equipment, tagging, temporary modifications, and equipment restoration did not place the plant in an unacceptable configuration; and (3) reviewed the CAP to determine if the licensee identified and corrected risk assessment and emergent work control problems.

- October 21, 2004, Unit 2, failure of reactor trip breaker Train C to close during surveillance test

- October 22, 2004, Units 1 and 2, actions associated with identification of corrupted surveillance data for control element assembly rod drop times

- November 27, 2004, Unit 2, loss of the COLSS system on both the plant computer and CMC as described in CRDR 2757396

- November 29, 2004, Unit 1, EDG Train B loss of proper speed indication and starting air leakage following a simulated engineered safeguards feature start and associated troubleshooting per Work Mechanism 2758279

- December 10-16, 2004, Unit 2,150-ton crane fell over and impacted turbine cooling water heat exchanger Train B as described in CRDR 2760702

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Nonroutine Plant Evolutions and Events (71111.14, 71153)

a. Inspection Scope

The inspectors (1) reviewed operator logs, plant computer data, and/or strip charts for the below listed evolutions to evaluate operator performance in coping with nonroutine events and transients; (2) verified that the operator response was in accordance with the response required by plant procedures and training; and (3) verified that the licensee has identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the nonroutine evolutions sampled.

- On December 16, 2004, Unit 1, Technical Specification required downpower due to power supply failure of the COLSS. Power was reduced to 38 percent until CMC COLSS was restored. This event was documented in CRDR 2761848.

- On December 31, 2004, during maintenance and testing at an off-site switchyard, by non-Palo Verde personnel, EDGs on 2A and 3B started and loaded due to undervoltage on their respective buses. Both EDGs started and loaded as designed. The loss of power to the two safety buses was the result of the de-energization of a startup transformer when the West Wing 2 transmission line at the Palo Verde switchyard, relayed off. Prior to the event, the maintenance and testing that had been in progress was on another transmission line. The apparent cause of the event was inadvertent operation of a protective relay on the West Wing 2 transmission line. Additionally, during the shutdown of EDG 2A, the EDG was declared inoperable due to a jacket water leak. This event was documented in CRDR 2764549.

- On September 5, 2004, the licensee operated Unit 1 low pressure safety injection (LPSI) and CS pumps to ensure that there were no air entrainment concerns. Low pressure safety injection Train A was declared inoperable due to an abnormal hydraulic response. The licensee then proceeded to start LPSI Pump B and noted proper system response. Following testing of LPSI Train B, Procedure 40OP-9CH12, “Refueling Water Tank (RWT) Operation,“ required depressurization of the LPSI Train B discharge header. The licensee declared LPSI Train B inoperable during the depressurization, and subsequently determined that an inadvertent entry into Technical Specification 3.0.3 occurred for approximately 5 minutes. An engineering evaluation of the system configuration showed that LPSI Train B was operable during the depressurization. This event was documented in CRDR 2735332.

- On September 6, 2004, during walkdowns of the SI system for air entrainment, the licensee discovered that the Unit 2 high pressure safety injection Train A hot-leg recirculation pipe had moved out of a structural support. Engineering performed a stress analysis of the as-found condition and determined that code allowable limits were not exceeded. The licensee implemented corrective actions to restore the required structural support for the recirculation pipe. This event was documented in CRDR 2735388.

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors (1) reviewed plants status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the Updated Safety Analysis Report and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any Technical Specifications; (5) used the significance determination process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- October 14, 2004, Units 2 and 3, CRDR 2745317 evaluation of gaskets on Trains A and B shutdown cooling suction valves from containment recirculation sumps that were not per design

- October 15, 2004, Units 1, 2, and 3, Operability Determination 278, “Operability Determination for Selected Rotork Valve Operators Subject to 10 CFR 50.21"

- October 21, 2004, Units 1 and 3, evaluation of foreign material identified in Steam Generator 32 and transportability review for Unit 1 steam generators documented in CRDR 2746969

- November 11, 2004, Unit 3, evaluation of dent in reactor head from an insulation pin that was apparently crushed between the underside of the multiple stud tensioner flange and the top flange of the reactor head documented in Deficiency WO 2748684

- November 11, 2004, Units 2 and 3, evaluation of discrepancy noted between the design modification pressurizer heater sleeve bore and values contained in the original pressurizer design report documented in CRDR 2752688

The inspectors completed five samples.

b. Findings

Introduction. The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” for failing to follow the timeliness requirements noted in Procedure 40DP-9OP26, “Operability Determination,” Revision 12.

Description. On November 9, 2004, the licensee initiated CRDR 2752688 noting a problem with the maximum diametrical clearance allowed between the pressurizer heater sleeve and the heater sheath. The diametrical clearance is the annular gap between the outside of the heater sheath and the inside of the heater sleeve and is part of the RCS pressure boundary. ASME Code Case 1361-2 allows a diametrical clearance of 0.045 inches, however, the licensee’s design modification allowed for a 0.055-inch clearance. This increased clearance was outside the analyzed design configuration for the structural adequacy of the RCS pressure boundary at this location.

The issue had been discussed for several days prior to the initiation of CRDR 2752688 due to questions from another utility who wanted to install a similar modification. The inspectors reviewed the timeline for this issue and noted that the applicability of the ASME code case to Palo Verde was known on Monday, November 8, and confirmed Tuesday, November 9, when CRDR 2752688 was initiated. On Wednesday, November 10, engineering personnel met with licensing personnel to submit a relief request to the NRC. Licensing recommended that engineering contact the Unit 2 control room. Unit 2 subsequently entered Technical Requirements Manual TLCO 3.4.103, for structural integrity, and started the operability determination process.

Analysis. This performance deficiency was associated with engineering personnel not adequately implementing the provisions of the operability determination procedure following the identification of a nonconforming condition. This finding was more than minor because the failure to follow the operability determination process, if left uncorrected, would become a more significant safety concern. Using the Phase 1 worksheet in Manual Chapter 0609, "Significance Determination Process," the finding is determined to have very low safety significance because it only affects the initiating events cornerstone and did not result in actual degradation of the RCS boundary. This finding involved problem identification and resolution (PI&R) crosscutting aspects associated with engineering personnel not informing the control room in a timely manner. Similar timeliness issues of reporting adverse conditions to the control room by engineering personnel were noted in adverse CRDRs 2733983 and 2734037, dated August 26, 2004.

Enforcement. 10 CFR Part 50, Criterion V, “Instructions, Procedures, and Drawings,” states, in part, that “Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.” Administrative Procedure 40DP-9OP26, “Operability Determination,” Revision 12, Section 2.1 states, “Whenever the ability of an SSC to perform its specified function is called into question by either an indication of a potential deficiency, loss of quality, degradation or nonconformance, then the individuals’s leader and the shift manager/shift technical advisor shall be immediately notified.” Contrary to these requirements, on November 9, 2004, engineering personnel failed to immediately inform the shift managers when a nonconformance with the ASME Code was identified as required by Procedure 40DP-9OP26. Because this finding is of very low safety significance and has been entered into the CAP as CRDR 2754848, this violation is being treated as a NCV consistent with Section VI.A of the NRC Enforcement Policy:
NCV 05000529/2004005-02, “Failure to Follow Operability Determination Procedure.”

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

Annual Review

The inspectors reviewed key affected parameters associated with energy needs, materials/replacement components, pressure boundary, structural, process medium properties, licensing basis, and failure modes for the modification listed below. The inspectors verified that (1) modification preparation, staging, and implementation does not impair emergency/abnormal operating procedure actions, key safety functions, or operator response to loss of key safety functions; (2) postmodification testing will maintain the plant in a safe configuration during testing by verifying that unintended system interactions will not occur, SSC performance characteristics still meet the design basis, the appropriateness of modification design assumptions, and the modification test acceptance criteria has been met; and (3) the licensee has identified and implemented appropriate corrective actions associated with permanent plant modifications.

- November 17, 2004, Unit 3, Modification 2513818, "Pressurizer Heater Sleeve Modification to Address PWSCC Issues"

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the four below listed postmaintenance test activities of risk significant systems or components. For each item, the inspectors (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met; plant impacts were evaluated; test equipment was calibrated; procedures were followed, jumpers were properly controlled, the test data results were complete and accurate; the test equipment was removed; the system was properly realigned; and deficiencies during testing were documented. The inspectors also reviewed the CAP to determine if the licensee identified and corrected problems related to postmaintenance testing.

- October 19, 2004, Unit 3, EDG Train A following outage overhaul per WO 2728901

- November 29-30, 2004, Unit 3, work on SI check Valves SI 627, 637, and 647 per WOs 2607928, 2607936, and 2714782, respectively

- November 30, 2004, Unit 1, airpax unit replacement for EDG Train B per WO 2758279

- December 5-6, 2004, Unit 3, work on SI Tank 2A vent Valves 603 and 613

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the following risk significant refueling items or outage activities to verify defense in depth commensurate with the outage risk control plan and compliance with the Technical Specifications: (1) the risk control plan, (2) tagging/clearance activities, (3) RCS instrumentation, (4) electrical power, (5) decay heat removal, (6) spent fuel pool cooling, (6) inventory control, (7) reactivity control, (8) containment closure, (9) reduced inventory or midloop conditions, (10) refueling activities, and (11) heatup and cooldown activities, and (12) licensee identification and implementation of appropriate corrective actions associated with refueling and outage activities.

b. Findings

Introduction. A Green NCV was identified for an inadequate procedure which resulted in an RCS level deviation during the RCS draindown to midloop conditions.

Description. On October 5, 2004, the licensee implemented Procedure 40OP-9ZZ16, “RCS Drain Operations,” Revision 45, to reduce RCS inventory to establish midloop conditions. During this draindown evolution, at a level of approximately 111.5 feet, a 2-foot sudden increase in reactor level indication occurred. Operators stopped the draindown and stabilized RCS level in response to this level anomaly. The licensee determined that the level deviation correlated to establishing increased reactor head venting when a heated junction thermal-couple connection was opened.

NRC Integrated Inspection Report 05000528/2004004; 05000529/2004004; and 05000530/2004004, Section 4OA3.6, described a similar event where the level deviation was preceded by a static head difference between the water columns in the pressurizer/surge line and the reactor. The static head difference is equal to the pressure drop across the reactor head vent line orifice, and produces a lag between pressurizer level and reactor level during a draindown to create a condition where actual RCS level is greater than indicated level. Corrective actions in response to the event included incorporation of additional hold points in Procedure 40OP-9ZZ16 and a reduced drain rate to provide controlled equalization of the static head difference during draindown evolutions. On October 5, 2004, the RCS drain rate exceeded the reactor head venting capacity and did not minimize the static head difference. This resulted in rapid pressure equalization between the pressurizer and reactor when the heated junction thermocouple connection was opened and a corresponding sudden increase in reactor level indication.

The inspectors questioned the licensee regarding the engineering justification for the drain rates allowed by Procedure 40OP-9ZZ16 and acceptability of the static head difference that had preceded these RCS level deviation events. The licensee was unable to provide engineering justification, and to the contrary, identified engineering documents that specified drain rates that were limited to values that corresponded to reactor head venting capabilities. Consequently, the licensee revised Procedure 40OP-9ZZ16 to reduce drain rates to values that would minimize the static head difference and the corresponding difference between actual and indicated RCS level.

Analysis. The deficiency associated with this event was an inadequate procedure which led to the excessive static head difference that preceded the RCS level anomaly. The finding was greater than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone and affects the cornerstone objective of ensuring the reliability of systems that respond to initiating events. The inadequate procedure resulted in an actual indicated level transient while the RCS was being drained in reduced inventory conditions. Using Manual Chapter 0609, Appendix G, “Shutdown Operations Significance Determination Process,” this finding is determined to have very low safety significance because the event did not constitute a loss of control and did not represent a finding requiring quantitative assessment. The finding did not increase the likelihood of loss or cause a degradation in the ability to restore decay heat removal, RCS inventory, offsite power, alternate core cooling, or containment. The inspectors noted PI&R crosscutting aspects that contributed to the finding in that engineering documents were available that specified correct drain rates, but these drain rates were not referenced until NRC inspectors questioned the justification of the procedurally allowed values.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, Procedure 40OP-9ZZ16, “RCS Drain Operations,” Revision 45, was inadequate in that it did not provide reduced drain rates or increased hold points to minimize the excessive difference between actual and indicated RCS level caused by static head difference between the pressurizer/surge line and the reactor. Because the finding is of very low safety significance and has been entered into the CAP as CRDR 2742525, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000530/2004005-03, “Excessive RCS Drain Rates Used to Establish Midloop Conditions.”

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the UFSAR, procedure requirements, and Technical Specifications to ensure that the seven below listed surveillance activities demonstrated that the SSC’s tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated Technical Specification operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- October 19, 2004, Unit 3, Procedure 73ST-9DG01, “Class 1E Diesel Generator and Integrated Safeguards Test Train A,” Revision 8
- October 26, 2004, Unit 3, local leakage rate testing for Containment Penetration 52 per Procedure 73ST-9CL01, "Containment Leakage Type “B” and “C” Testing," Revision 25
- November 2, 2004, Unit 1, Procedure 40ST-9RC02, “ERFDADS (Preferred) Calculation of RCS Water Inventory,” Revision 26, Section 8.0
- November 9, 2004, Unit 3, Procedure 31ST-9SI01, “Cleaning Inspection of ECCS Sumps,” Revision 8
- November 9, 2004, Units 1 and 2, Procedure 40ST-9ZZ13, "Containment Isolation Valves,” Revision 3
- December 2, 2004, Unit 2, Procedure 40ST-9RC02, “ERFDADS (Preferred) Calculation of RCS Water Inventory,” Revision 26, Section 8.0
- December 15, 2004, Unit 3, Procedure 73ST-9DF01, “Diesel Fuel Oil Transfer Pump - Inservice Test,” Revision 14

The inspectors completed seven samples.

b. Findings

.1 Containment Isolation Valve (CIV) Position Verification

Introduction. A Green NCV of Technical Specification Surveillance Requirement 3.6.3.3 was identified regarding an inadequate surveillance procedure for vents and drains associated with the SI system containment penetrations.

Description. On November 9, 2004, the inspectors identified that SI Containment Penetrations 13-20 were not maintained in compliance with the requirements of 10 CFR Part 50, Appendix A, General Design Criteria (GDC) 55, and Technical Specification Surveillance Requirement 3.6.3.3. General Design Criteria 55 requires either automatic CIVs inside and outside containment or an automatic isolation valve on one side of containment and a locked closed isolation valve on the other side of containment. The injection pathway CIVs must be open for the SI system piping since it would be used to mitigate the consequences of accidents and, therefore, do not receive an automatic closure signal and are not locked closed. UFSAR, Section 3.1.48, documents an exception to GDC 55 that addresses the injection pathways in these penetrations.

Containment Penetrations 13-20 also have test connection or drain valves located between the CIVs. There is no exemption noted in the UFSAR to not maintain these test connections and drain valves closed and these valves are not a part of the main flow path. Compliance with GDC 55 would require the test and drain valves located between these CIVs be locked closed; however, these valves are not included in Procedure 40ST-9ZZ13, “Containment Isolation Valves,” Revision 4, or in the implementing Procedure 40DP-9OP19, “Locked Valve, Breaker and Component Tracking,” Revision 83. Following inspectors identification of the inadequate surveillance procedure, the licensee verified all vent and drain valves associated with Containment Penetrations 13-20 were closed.

Analysis. The deficiency associated with the finding was an inadequate procedures used to implement technical specification surveillance requirements. The failure to perform the required surveillance to ensure these valves remained in the correct position was determined to be greater than minor because if left uncorrected, it would become a more significant safety concern. Additionally, the finding was associated with the configuration control attribute of the barrier integrity cornerstone and affects the cornerstone objective to provide reasonable assurance that the containment physical design barrier is preserved to protect the public from radio nuclide releases caused by accidents or events. Using the Phase 1 worksheet in Manual Chapter 0609, "Significance Determination Process," the finding is determined to have very low safety significance because it only affected the barrier integrity cornerstone, all the valves were found closed, and did not result in an actual open pathway out of the reactor containment.

Enforcement. Technical Specification Surveillance Requirement 3.6.3.3 states that every 31 days in Modes 1, 2, 3, and 4 to “Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed or otherwise secured and is required to be closed during accident conditions is closed, except for CIVs that are open under administrative controls.” Contrary to the above, prior to November 9, 2004, the vents and drains associated with Containment Penetrations 13-20 were not verified as closed every 31 days. Because the finding is of very low safety significance and has been entered into the CAP as CRDR 2753335, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528/2004005-04; 05000529/2004005-04; and 05000530/2004005-04, “Failure to Include Vents and Drains into Locked Valve Program.”

.2 EDG Fuel Oil Transfer Pump Electrical Conduit Water Intrusion

Introduction. A Green NCV was identified by the inspectors for an inadequate operability assessment of EDG fuel oil transfer pump Train A following identification of water in the electrical conduit and junction boxes associated with the power supply to the pump.

Description. On December 15, 2004, while performing Surveillance Procedure 73ST-9DF01, “Diesel Fuel Oil Transfer Pump - Inservice Test,” Revision 14, an operator observed water coming out of the conduit box associated with the power supply for EDG fuel oil transfer pump Train A. Subsequent investigation determined that accumulation of water in the junction box caused a degradation of the electrical cabling to the EDG fuel oil transfer pump resulting in a ground resistance reading of 50 kohms. Emergency Diesel Generator Train A was declared inoperable since the ground resistance reading was less than the minimum operability limit of 50 Mohms. The source of the water intrusion could not be determined, however, it appeared to be rain water that had entered the conduit at some point between the EDG building and EDG fuel oil vault.

The licensee implemented corrective actions to drain the water from the affected junction box, dry out the conduit, and drill a hole into the bottom of the conduit box to ensure it remained drained. Additionally, preparations were initiated to complete Technical Specification Required Action 3.8.1.B.3.1, which requires the determination that the operable EDG is not inoperable due to common cause failure within 24 hours. The common cause failure verification of EDG Train B was delayed until EDG Train A was declared operable. Following corrective actions, satisfactory ground resistance readings, and postmaintenance testing, the licensee determined that a degraded condition no longer existed with the EDG fuel oil transfer system and declared EDG Train A operable. The licensee did not identify water in the conduit box for EDG Train B during the common cause failure inspection.

The licensee did not consider the deficient condition that allowed water intrusion into the conduit and conduit box to be a condition that could impact EDG operability. The inspectors questioned the licensee as to whether the corrective actions had been properly evaluated to ensure that an operability concern did not exist due to the potentially degraded condition that could result from water intrusion. The inspectors expressed concerns that the hole drilled in the conduit box may not be sized properly since the ingress rate of water was not known; that debris could wash into the conduit box and plug the hole to prevent draining; and that it had not been determined whether the electrical cables were qualified for submergence. Subsequent engineering review identified that the hole in the bottom of the conduit box may not be adequately sized, and that the corrective action taken would create a condition in the fuel oil vault that was not in accordance with the UFSAR and other licence basis documents. Specifically, the corrective action to drain water from the bottom of the conduit box compromised the waterproof design of the EDG fuel oil vault. Following the recognition that the water in-leakage could impact operability of the EDG, the licensee implemented additional corrective actions to seal the electrical conduit to prevent water from entering the conduit junction box and fuel oil vault. Additionally, an engineering evaluation determined that the electrical cables were suitable for use in submerged locations.

Analysis. The performance deficiency associated with the finding was the failure to follow an administrative procedure when the operability of a safety-related component was potentially impacted. The finding was more than minor since it was associated with the equipment performance attribute of the mitigating system cornerstone and affects the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events. Using the Significance Determination Process Phase 1 worksheet, the finding was determined to have very low safety significance because it only affects the mitigating system cornerstone and was a deficiency that did not result in the actual loss of the safety function of the EDG. The inspectors noted PI&R crosscutting aspects in that licensee personnel failed to recognize water intrusion into the conduit box as a potential deficiency that could impact EDG operability until prompted by the inspectors.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures. Contrary to this, the licensee performed activities affecting quality that were not in accordance with documented procedures. Specifically, Administrative Procedure 40DP-9OP26, "Operability Determination," Revision 12, Section 2.0 states, "Whenever the ability of an SSC to perform its specified function is called into question by either an indication of a potential deficiency, loss of quality, degradation or nonconformance, then the individual's leader and the shift manager/shift technical advisor shall be immediately notified," initiating entry into the operability determination process. Contrary to these requirements, on December 15, 2004, engineering and operations personnel failed to consider water intrusion into the electrical conduit for EDG fuel oil transfer pump Train A as a condition that could affect the ability of the EDG to perform its specified function, and consequently, declared EDG Train A operable without following the requirements of Administrative Procedure 40DP-90P26. Because this finding is of very low safety significance and has been entered into the CAP as CRDR 2763326 this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000530/2004005-05, "Failure to Follow the Operability Determination Process for a Degraded Condition."

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspectors assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR Part 20 and the procedures required by Technical Specifications as criteria for determining compliance. The inspectors interviewed licensee personnel and reviewed:

- Current 3-year rolling average collective exposure
- Five outage and on-line maintenance work activities, previous work history data, and associated work activity exposure estimates which resulted in the highest personnel collective exposures

- Site specific ALARA procedures
- Five work activities of highest exposure significance occurring during the inspection and completed during the last outage
- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements
- Intended versus actual work activity doses and the reasons for any inconsistencies
- Interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling and engineering groups
- Integration of ALARA requirements into work procedure and radiation exposure permit documents
- Postjob (work activity) reviews
- Assumptions and basis for the current annual collective exposure estimate, the methodology for estimating work activity exposures, the intended dose outcome, and the accuracy of dose rate and man-hour estimates
- Method for adjusting exposure estimates, or replanning work, when unexpected changes in scope or emergent work were encountered
- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding and alternate work methods
- Workers use of the low dose waiting areas
- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas
- Declared pregnant workers during the current assessment period, monitoring controls, and the exposure results
- Self-assessments, audits, and special reports related to the ALARA program since the last inspection
- Resolution through the corrective action process of problems identified through postjob reviews and postoutage ALARA report critiques
- Corrective action documents related to the ALARA program and followup activities such as initial problem identification, characterization, and tracking

- Effectiveness of self-assessment activities with respect to identifying and addressing repetitive deficiencies or significant individual deficiencies

The inspectors completed 13 of the required 15 samples and 6 of the optional samples.

b. Findings

Introduction. The inspectors reviewed a Green self-revealing NCV of Technical Specification 5.7.1.b in which a radiation worker could not hear an electronic dosimeter alarm in a high radiation area.

Description. On September 30, 2003, an individual, performing work in a high radiation area received an electronic dosimeter dose alarm but could not detect it. The individual did not respond to the alarm until after entering another area with lower ambient noise. The dosimeter had alarmed for approximately 30 minutes. The licensee determined that the individual had a hearing deficiency.

Analysis. The failure to provide an effective alarming dosimeter to a worker entering a high radiation area was a performance deficiency. This finding was considered more than minor because it is associated with the occupational radiation safety program and process attribute and affects the cornerstone objective because the failure to hear an electronic dosimeter alarm could increase personnel dose.

This occurrence involved a worker's unplanned, unintended dose, or potential for such a dose that could have been significantly greater as a result of a single minor, reasonable alteration of the circumstances; therefore, this finding was evaluated with the occupational radiation safety significance determination process. The inspectors determined that the finding was of very low safety significance because it did not involve: (1) ALARA planning and controls, (2) an overexposure, (3) a substantial potential for overexposure, or (4) an impaired ability to assess dose.

Enforcement. Technical Specification 5.7.1.b states, in part, that any individual permitted to enter a high radiation area shall be provided with a radiation monitoring device that continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. The licensee violated this requirement on September 30, 2003, when it failed to provide an effective alarming dosimeter to a worker entering a high radiation area. The violation was of very low safety significance and was entered into the licensee's CAP as CRDR 2689876. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000529/2004005-06, "Failure to Comply with High Radiation Area Technical Specification Requirement."

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors sampled licensee submittals for the two performance indicators on all three units listed below for the period from December 2003 through October 2004 The inspectors verified: (1) the accuracy of the performance indicator data reported during that period and (2) used the performance indicator definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Indicator Guidelines," Revision 2, to verify the basis in reporting for each data element.

- RCS specific activity (Units 1, 2, and 3)
- RCS identified leak rate (Units 1, 2, and 3)

The inspectors reviewed chemistry sample records, Technical Specifications, completed surveillances, operator log entries, RCS leakage database, and performance indicator data sheets to determine whether the licensee adequately verified the performance indicators listed above. This number was compared to the number reported for the performance indicator during the past 3 quarters. Also, the inspectors interviewed licensee personnel responsible for compiling the information.

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

The inspectors reviewed a selection of CRDRs written during this period to determine if the licensee was entering conditions adverse to quality into the CAP at an appropriate threshold; the CRDRs were appropriately categorized and dispositioned in accordance with the licensee's procedures; and in the case of conditions significantly adverse to quality, the licensee's root cause determination and extent of condition evaluation were accurate and of sufficient depth to prevent recurrence of the condition.

b. Findings

No findings of significance were identified.

.2 Annual Sample Review

a. Inspection Scope

Section 2OS2 evaluated the effectiveness of the licensee’s PI&R processes regarding exposure tracking, higher than planned exposure levels, and radiation worker practices. The inspector reviewed the corrective action documents listed in the attachment against the licensee’s PI&R program requirements.

In addition, NRC Inspection Report 05000528; -529; -530/2004011 documented the results of a sample reviewed for an incident involving the movement of irradiated fuel.

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

Inspectors conducted an in-office review of condition reports/disposition requests (CRDRs) associated with all trips and down powers that occurred during the past five years and all 2003 and 2004 violations and licensee event reports. The items reviewed were analyzed in spreadsheet format. The analysis included age, affected cornerstone(s), trending codes as binned by the licensee and inspectors, and observations and potential follow-up items. To assure consistency, the two inspectors performed and validated a small sample of initial analyses for comparison.

The objective was to identify trends or patterns (either NRC or licensee identified) that might indicate the existence of a more significant safety issue. Secondary objectives were to determine if the licensee was entering conditions adverse to quality into the corrective action program at an appropriate threshold; the CRDRs were appropriately categorized and dispositioned in accordance with the licensee's procedures; and in the case of significant conditions adverse to quality, the licensee's root cause determinations and extent of condition evaluations were accurate and of sufficient depth to prevent recurrence of the condition.

The review was performed by summarizing the licensee’s assigned causal factors and comparing those results to those independently identified by the inspectors. Trend coding was performed by using six major categories: administrative programs, training, management oversight, human performance, work environment, and organizational weaknesses. Inspectors evaluated the CRDRs against the requirements Procedure 90DP-0IP10, “Condition Reporting,” and PID Coding and Trending Desk Instruction. During the reviews of CRDRs, the inspectors identified that many equipment issues were not dispositioned through the CRDR process, but were instead dispositioned using Procedure 30DP-9WP02, “Work Document Development and Control,” and Procedure 30DP-0RA01, “Component Failure Trending.” The work control process was not reviewed in detail.

b. Findings and Observations

There were no findings identified with any specific samples, however, the inspectors observed several trends. The trends included inconsistency in identifying issues within the CRDR program, a pattern of reacting to equipment failures, backlog of significant CRDRs, procedure adherence and inadequacies, and the failure to identify management/supervisory errors.

There are many examples of the licensee not identifying issues with CRDRs, which is allowed by their program; however, numerous components that failed during events appear to have been dispositioned through the work control process versus being identified and evaluated in the CRDR process, resulting in long standing or repetitive equipment problems. For example, operations personnel generated a work mechanism (work order) for an incorrect safety equipment actuation status light check for a containment isolation valve on June 10, 2004. The component was worked on July 19, 2004 and maintenance personnel identified that the switch was wired incorrectly, a CRDR was initiated. The valve was subsequently determined to be inoperable since May 24, 2004 following maintenance on the limit switch.

The CRDR process more specifically trends and evaluates programmatic/process issues, and the work control program assesses failure modes and causal codes for hardware issues. Since the CRDR process is intentionally separated from the work control process, both organizationally (different organizations are responsible for trending each process, with different cause codes, and the groups do not communicate with each to look for common trends) and procedurally, the two separate processes complicate the identification and disposition of issues. Both programs have operability assessment requirements; however, the level of rigor and oversight for the work control process is considerably less than for the CRDR process. For example, each CRDR is reviewed for operability concerns by the CRDR Review Committee, which consists of seven people from different organizations. In addition, for CRDRs classified as significant or potentially significant, these CRDRs are reviewed at the plan of the day meetings. Work orders are reviewed for operability concerns by one work control senior reactor operator. The disconnect between the two programs may result in missed opportunities in identifying hardware programmatic issues and hardware failures associated with human performance errors

The majority of issues that the inspectors reviewed were either self-revealing or NRC identified versus licensee identified. Of the 81 significant/adverse CRDRs reviewed, 51 were self-revealing and 21 were NRC identified. The licensee only identified 11 percent of the more significant issues at the plant. NRC inspectors identified the following issues:

Refueling personnel continued to move spent fuel even though they had determined that the refueling machine sprag brake had failed. Fuel movement was stopped only after an NRC inspector questioned the operability of the refueling machine hoist (NCV 2004003-04 and CRDR 2704331).

Engineering personnel failed to identify that the failed resistors in the power supply to the turbine driven auxiliary feedwater pump governor control circuits in Units 2 and 3 that had transportability to Unit 1 (NCV 2004004-02 and CRDR 2746954).

Since 2001, the licensee discontinued implementation of required Technical Specification surveillance testing for the containment purge valves by declaring the valves inoperable and installing blind flanges instead of restoring the valves to an operable condition at the next available opportunity (NCV 2004003-02 and CRDR 2711167).

As part of the review, the inspectors identified instances when the licensee either delayed or failed to evaluate and/or correct the adverse condition. In addition, several of the CRDRs reviewed actually stated concerns with schedule pressure. The following examples are either recent CRDRs or events that were not promptly evaluated:

Delay in performing operability assessment for voiding of ECCS sump suction piping (NCV 2004014-02 and CRDRs 2733983 and 2734037).

Delay in inspecting and performing operability assessments associated with the emergency diesel generator fuel oil junction boxes for water intrusion (NCV 2004005-05, See Section 1R15).

A previous trip of Unit 3 Reactor Coolant Pump 2B lift oil pump motor was discounted without an adequate basis. The licensee did not pursue this issue and determine the root cause (NRC IR 2004-013 and CRDRs 2623273 and 2715659).

Refueling personnel, under operations directions, placed fuel into the core without audible count rates on a source range monitor contrary to T.S. requirements (CRDR 2654642).

The team identified a backlog of overdue significant CRDRs. The licensee also identified this trend in the monthly trend report, but no action plan has been developed by the licensee to address this trend. Procedure 90DP-0IP10, “Condition Reporting,” has no timeliness requirements; however, the licensee does have timeliness goals for significant root cause evaluations as described in a memo dated April 24, 2002: 30 days for an interim root cause report and 120 days for a final root cause report. In the October 2004 Trend Report, there were approximately 110 adverse and significant CRDRs that have open interim evaluations greater than 30 days. As of November 18, 2004, there were 25 significant CRDRs open. Of those, the licensee indicated that only six were overdue; however, there were 20 significant CRDRs beyond the 120 day goal.

The trend review indicated a potential procedure adherence/inadequacy problem. Of the 81 significant/adverse CRDRs reviewed, 32 (40 percent) were procedure related. Of those, 64 percent were procedure inadequacies and 36 percent were procedure adherence problems. The following are examples of consequential adherence failures:

Failure to operate the spent fuel handling machine in accordance with the procedure resulted in fuel damage. (NCV 2004011-01, CRDR 2711971)

Failure to correctly align the charging system resulted in a trip of the charging Pump. (NCV 2004013-07, CRDR 2736503)

Failure to properly implement venting during mid-loop operations led to low pressure safety injection pump cavitation and loss of shutdown cooling. (NCV 2004009-01, CRDR 2686273)

Of the entire population of CRDRs reviewed, the licensee had identified management and supervisory cause codes in only 20 percent of the CRDRs. During the review of 2004 CRDRs , the inspectors identified 10 CRDRs with leadership issues and the licensee identified only two. Of the CRDRs in the population dating back 5 years, the inspectors identified management and supervisory causal factors in four times as many CRDRs as the licensee's evaluation. A recent example was the control room supervisors involvement in the Unit 2 charging pump trip, during the loss of offsite power event (NCV 2004013-07 and CRDR 2716521). Based on this data, the inspectors concluded that the licensee was not adequately identifying management and supervisory cause codes when evaluating CRDRs. The licensee acknowledged this as a valid observation and noted that this trend was identified in the "Mid-Cycle Recommended Focus Area and First Quarter 2004 Trend Report," and in CRDR 2734665. The corrective actions to address supervisory effectiveness have not been completed.

The licensee completed a trend review on the same documents as described in the inspection scope. The licensee completed trend reviews of eight categories: surveillance testing, safety functions/fission product barrier, technical specifications, security, procedure inadequate, procedure non-adherence, radiation protection, and reactor operations (reactivity). The licensee did not identify any adverse trends. With the exception of surveillance testing, security, and radiation protection, all of the other trend categories showed upward trends for the past two years.

4OA3 Event Followup (71153)

.1 (Closed) LER 05000529/2003004-00, "Mode 3 Entry with an Auxiliary Feed Water Pump Inoperable"

This issue was dispositioned as an NCV in Inspection Report 05000528/2004002; 05000529/2004002; and 05000530/2004002 (NCV 05000529/2004002-05, Section 4OA5.1). The inspectors reviewed the LER and found no additional concerns than those previously identified and documented. This LER is closed.

.2 (Closed) LER 05000529/2004001-00, "Steam Generator Tube Leak"

This issue was dispositioned as an NCV in Inspection Report 05000529/2004009 (NCV 05000529/2004009-03, Section 4.1). The inspectors reviewed the LER and found no additional concerns than those previously identified and documented. This LER is closed.

.3 (Closed) LER 05000529/2003003-00, "Source Range Inoperable During Core Reload"

a. Inspection Scope

The inspectors reviewed this LER and CRDRs 2654704 and 2654642 to assess the cause analysis and corrective actions for this event.

b. Findings

Introduction. A Green self-revealing NCV was identified for performing core alterations with less than the required number of startup range monitors (SRMs).

Description. On November 23, 2003, the reactor was defueled and preparations were made to begin refueling. Both SRMs are required to be operable prior to the beginning of fuel movement. The licensee identified SRM Channel 2 indicated low, and initiated troubleshooting activities only at the instrument drawer to determine the cause of the apparent failure. No problems were identified during troubleshooting activities and a test input indicated that the SRM electronics located in the instrument drawer were functioning properly. SRM Channel 2 was declared operable, the mode change checklist completed, and refueling operations began.

In accordance with the fuel reload sequence, the first fuel assembly was placed near SRM Channel 1 which resulted in the proper response in that counts increased and then placed in the reactor. The second fuel assembly was placed near SRM Channel 2, however, no increase in indicated counts was observed and this assebly was placed in the reactor. SRM Channel 2 was again declared inoperable and the licensee investigated. Through more comprehensive troubleshooting, the licensee found that a connection at the electrical penetration did not have continuity. Consequently, SRM Channel 2 was not responding properly since the signal from the detector was not providing the proper input to the SRM. The connection was tightened, SRM Channel 2 was retested, and the instrument was declared operable.

Analysis. Performing core alterations without the required number of nuclear instruments is the performance deficiency. The finding was greater than minor because it affects the configuration control attribute of the barrier integrity cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Using Manual Chapter 0609, Appendix G, "Shutdown Operations Significance Determination Process," this finding was determined to have very low safety significance because the event did not constitute a loss of control and did not represent a finding requiring quantitative assessment. The finding did not increase the likelihood of loss or cause a degradation in the ability to restore decay heat removal, RCS inventory, offsite power, alternate core cooling, or containment.

Enforcement. Unit 1 Technical Specification 3.9.2, “Nuclear Instrumentation,” requires that two SRMs be operable in Mode 6. Contrary to the above, on November 23, 2004, the licensee performed core alterations (placing fuel into the reactor) with only one SRM operable. Because the finding is determined to have very low safety significance and has been entered in the licensee's corrective actions as CRDRs 2654704 and 2654642, this violation was being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000529/2004005-07, “Core Alterations with Less than Two Operable SRMs.”

.4 (Closed) LER 05000528/2004007-00; 05000529/2004007-00; 05000530/2004007-00, “Exceeding the Maximum Power Level Specified in Operating License Condition 2.C(1)”

The licensee installed external ultrasonic flow meters (UFM) on the plant feedwater piping in 1999 for Units 1 and 3, and 2000 for Unit 2. The UFM instruments were used to provide a more precise feedwater flow than the original measurement method of flow venturis since the UFMs were not prone to fouling, which is a condition that causes the venturi to overstate flow and results in overstated calorimetric power. The UFM output was one of the inputs used by the Core Operation Limits Supervisory System (COLSS) for the secondary calorimetric calculation. The excore nuclear instruments are calibrated to the power level that the COLSS system provides.

On July 14, 2004, during a review of historical operating data, the licensee concluded that the maximum specific calorimetric error was approximately 38.76 MW in Units 1 and 3 and 39.90 MW in Unit 2, or approximately 1 percent. The error resulted in core power levels above the Operating License limits of 3876 MW thermal for Units 1 and 3 and 3990 MW thermal for Unit 2 while the UFM instrument was in service. This review and its results were based on a letter received from the vendor to inform the licensee of potential errors in the flow measurement. Initial corrective actions were to reduce power levels in Units 1 and 3 to 96.5 percent power, remove the UFMs from service, change the input to the secondary calorimetric calculation to the venturis, and return to full power. Unit 2, which was in Mode 3, switched to venturi inputs prior to power operations. The safety analyses bound an operating power level of 102 percent. The power level during the time frame in which the UFMs were in service did not exceed the analyzed value.

This finding is greater than minor since it is associated with the design control attribute of the barrier integrity cornerstone and affects the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radio nuclide releases. Calibrating the excore neutron detectors with a non-conservative reactor power indication would cause the affected plant protection functions to trip at non-conservative reactor power levels. Using IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors determined that the finding affected the reactor fuel cladding barrier, but was of very low safety significance because the values were within the bounds of the accident analysis and fuel barrier integrity was not challenged during the overpower condition. This licensee-identified finding involved a violation of Operating License Condition 2.C(1), “Maximum Power Level.” The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

4OA5 Other Activities

.1 (Closed) Unresolved Item (URI) 05000528/2004012-08; 05000529/2004012-08; 05000530/2004012-08, “Unit 3, Low Pressure SI System In-Leakage”

a. Inspection Scope

During recovery from the June 14, 2004, loss of off-site power event, Valve RCEV-217, a 14-inch Borg-Warner check valve, began to leak and pressurized the SI header to Reactor Coolant Loop 2A in Unit 3. This issue was made unresolved to review the root and contributing causes, extent of condition, and corrective actions associated with the Borg-Warner SI check valve leakage; to review the effectiveness of prior corrective actions for previous check valve leakage issues; to evaluate the adequacy of the in-service testing program for demonstrating check valve operability; and to assess the use of industry operating experience and generic communications. This review was documented in Augmented Inspection Team Report 05000528/2004013; 05000529/2004013; and 05000530/2004013. However, this unresolved item remained open pending review of maintenance activities on Valve RCEV-217 during Refueling Outage U3R11.

Inspectors completed the inspection of the as-found alignment and seat conditions of Valve RCEV-217 and determined that the root cause of failure was unrelated to past Borg-Warner check valve deficiencies.

b. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel (RPV) Head and Vessel Head Penetration Nozzles TI 2515/150

In April 2003, the inspectors completed the first occurrence of TI 2515/150 and documented results in NRC Inspection Report 05000528/2003003; 05000529/2003003; and 05000530/2003003. The second occurrence of TI 2515/150 for Unit 3 is documented below. Therefore, TI 2515/150 is complete for Unit 3.

Susceptibility Ranking Calculation

a. Inspection Scope

In October 2004, the inspectors performed NRC Inspection Manual TI 2515/150 for Unit 3 during Cycle 11 Refueling Outage 3R11. The inspectors reviewed the licensee's inspection plan in response to NRC Order EA-03-009 which established interim inspection requirements for RPV heads.

The inspectors reviewed the susceptibility ranking calculation to verify that appropriate plant-specific information was used as input. The calculation determines the effective degradation years, which is the effective full power years, normalized to 600°F. Two periods were used to determine RPV head temperature and corresponded to the periods before and after implementation of T-hot reduction, which reduced T-hot from 621°F to approximately 612°F to minimize steam generator tube degradation. The head temperature for each period was based on using a combination of an evaluation to calculate fluid temperature in the upper head based on mixing of bypass flow through different paths and heated junction thermocouple data. The more conservative of the two temperatures was used for each period.

The inspectors noted that Unit 3 was in the highly susceptible category at the end of Cycle 11. Required inspections for the refueling outage were bare metal visual examination of 100 percent of the RPV head surface, and ultrasonic testing of each RPV head penetration nozzle or eddy-current testing of the wetted surface of each J-groove weld and RPV head penetration nozzle base material to at least 2 inches above the J-groove weld.

b. Findings

No findings of significance were identified.

Volumetric and Surface Examinations

This section of the TI was included as part of the sample required by Inspection Procedure 71111.08, “Inservice Inspection Activities” (Section 1R08).

Bare Metal Visual Examinations

a. Inspection Scope

The inspectors observed the video acquired during visual inspection of the RPV head vent line nozzle and noted that the camera and remote monitoring equipment used during the examination process provided adequate visual clarity. The inspectors reviewed certification records and discussed the qualifications and experience of the examiners. The inspectors verified that a clear 360° observation of the nozzles was completed and that no evidence of cracking or boric acid crystals were present. There were no boron deposits, debris, or insulating material which masked the ability to identify the existence of boric acid. There were no structural interferences which impeded the ability to complete the bare metal visual inspections. The inspectors determined that the licensee had procedures in place to identify leakage from pressure retaining components located above the RPV head.

b. Findings

No findings of significance were identified.

.3 (Closed) RPV Lower Head Penetration Nozzles TI 2515/152

a. Inspection Scope

In October and November 2004, the inspectors reviewed the licensee’s response to NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity." The response described the licensee’s commitment to perform a bare metal visual inspection of all 62 nozzle penetrations in the lower reactor head of all three units. The inspectors reviewed the licensee's procedures for the inspection of the Unit 3 lower head penetrations. The inspectors also reviewed the qualification and certifications for the personnel performing the inspections.

The inspectors reviewed video tapes and computer images of all nozzle inspections. The inspections covered a full 360° of all 62 nozzle penetrations. The camera and remote monitoring equipment used during the examination process provided adequate visual clarity. The inspectors verified that a clear 360° observation of the nozzles was completed and that no evidence of cracking or boric acid crystals were present. The inspectors determined that there was insulation or boric acid deposits at the interface between the vessel and penetrations on the RPV lower no debris head that would obstruct visual inspection. The licensee was able to clean 23 and partially clean 2 penetration nozzles to establish a baseline for future inspections.

TI 2515/152 has been completed on Units 1, 2, and 3.

b. Findings

No findings of significance were identified.

.4 (Closed) Reactor Containment Sump Blockage - NRC Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors" TI 2515/153

Generic Safety Issue 191 was established to determine whether the transport and accumulation of debris in PWR containments following a loss of coolant accident (or other high energy line break, if recirculation is credited) will impede the long-term operation of the emergency core cooling system (ECCS) or CS system. In the event of a LOCA, materials in the vicinity of the break, such as thermal insulation, coatings, and concrete, would be damaged and dislodged.

The inspectors reviewed the licensee's response and supporting basis which showed that the ECCS and CS system recirculation functions have been analyzed with respect to the potentially adverse post-accident debris blockage effects as specified in the bulletin. The inspectors assessed that this determination was based on a mechanistic (plant-specific) evaluation of debris generation, transport, and accumulation, rather than arbitrary (generic) assumptions.

The inspectors also assessed that the licensee performed walkdowns of their containments to quantify potential debris sources and check for gaps in the sumps' screened flowpath and for major obstructions in containment upstream of the sumps.

The inspectors also assessed any sump-related modifications.

TI 2515/153 has been completed on Units 1, 2, and 3.

Debris Sources in Containment

a. Inspection Scope

The potential debris sources in containment are described in UFSAR, Section 6.2.2, and in Calculation 13-MC-SI-309. The inspectors toured Unit 3 containment for identified potential debris sources to verify that there were no additional debris sources.

b. Findings

No findings of significance were identified.

Containment Sump Inspection and Design

a. Inspection Scope

The inspectors reviewed the design of the containment sumps which were designed to be reservoirs of water to the ECCS following a LOCA. The design requirements for the sumps were to filter the RCS water to preclude particles greater than 3/16-inch diameter from entering the ECCS sump.

b. Findings

No findings of significance were identified.

.5 Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. PWRs TI 2515/160

In November 2004, the inspectors reviewed the licensee's response to NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized Water Reactors." The response described the licensee's plan to replace all of the pressurizer heater sleeves with thermally treated SB-167, Alloy 690 sleeves using the 1/2 nozzle repair technique. This project was completed for Unit 3 during Refueling Outage U3R11.

The inspectors reviewed the records for visual examinations of the Class 1 pressure boundary piping and the connections coming from the pressurizer, and verified that the examinations were performed in accordance with site procedures and the applicable ASME Code requirements. The scope of the visual examination included Alloy 600 penetrations, all 82/182 dissimilar metal welds, and all Class 1 bolted connections (pressurizer manway). The inspectors also verified that the visual examinations were performed by qualified and knowledgeable personnel.

4OA6 Meetings, Including Exit

On November 5, 2004, the inspectors presented the ALARA inspection results to Mr. J. Gaffney, Radiation Protection Director, and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

The inspectors presented the results of this portion of the inspection effort to Mr. David Mauldin, Vice President, Engineering and Support, and other members of licensee management on October 15, 2004, followed by a telephonic exit meeting on November 10, 2004. Licensee management acknowledged the inspection results.

The resident inspectors presented the inspection results of the resident inspections to Mr. G. Overbeck, Senior Vice President, Nuclear, and other members of the licensee's management staff on January 7, 2005. The licensee acknowledged the findings presented.

The inspectors noted that while proprietary information was reviewed, none would be included in this report.

4OA7 Licensee-Identified Violations

The following violations of very low significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- 10 CFR 50.59 requires that changes to the plant be properly screened and evaluated prior to implementation. Procedure, 93DP-OLC07, "10CFR 50.59 and 72.48 Screenings and Evaluations," Revision 7 requires that adverse changes be addressed via 10 CFR 50.59 Evaluations. Contrary to the above, the licensee performed an inadequate screening which allowed emergency operating procedures to be administratively changed to add steps to open hydrogen recombiners valves with Rotork actuators within 10 minutes of a LOCA. The 10 CFR 50.59 screening should have required a full evaluation. This event is documented in the licensee's CAP as CRDR 2745330. This finding is only of very low safety significance because the finding did not represent an actual degradation in the containment barrier.

- Operating License Condition 2.C(1), "Maximum Power Level," limits core power levels to 3876 MW thermal for Units 1 and 3 and 3990 MW thermal for Unit. Contrary to this, licensed maximum power level was exceeded in Units 1 and 3 since 1999 and in Unit 2 since 2000 for periods when the UFM was in service due to a non-conservative feedwater flow input to the secondary calorimetric calculation. This finding was documented in CRDR 2743258 and LER 05000528; -529; -530/2004007-00 (see Section 4A03.4 for LER closure discussion).

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

S. Bauer, Department Leader, Regulatory Affairs
P. Borchert, Director, Work Management
R. Buzard, Sr. Consultant, Regulatory Affairs
D. Carnes, Director, Regulatory Affairs/Nuclear Assurance
P. Carpenter, Unit Department Leader, Operations
K. Coon, Technical Management Assistant, Radiation Protection
S. Coppock, Department Leader, System Engineering
E. Dutton, Section Leader, Nuclear Assurance
D. Fan, Department Leader, Design Mechanical Engineering
M. Fladager, Operations Department Leader, Radiation Protection
J. Gaffney, Director, Radiation Protection
T. Gray, Radiological Services Department Leader, Radiation Protection
M. Grigsby, Unit Department Leader, Operations
J. Hesser, Director, Emergency Services
D. Marks, Section Leader, Regulatory Affairs
M. McGhee, Unit Department Leader, Operations
G. Overbeck, Senior Vice President, Nuclear Operations
D. Mauldin, Vice President, Engineering and Support
M. Radsprinner, Section Leader, Systems Engineering
T. Radtke, Director, Operations
F. Riedel, Director, Nuclear Training Department
C. Seaman, Director, Nuclear Fuel Management
M. Shea, Director, Maintenance
D. Smith, Plant Manager, Production
B. Sneed, ALARA Planning Section Leader, Radiation Protection
M. Sontag, Department Leader, Nuclear Assurance
R. Sorensen, Department Leader, Chemistry
D. Straka, Senior Consultant, Regulatory Affairs
K. Sweeney, Section Leader, Steam Generator Project Group
J. Taylor, Department Leader, Operations Support
T. Weber, Section Leader, Regulatory Affairs
D. Wheeler, Section Leader, Nuclear Assurance Department
M. Winsor, Director, Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000530/2004005-01	NCV	Failure to Provide Adequate Maintenance Procedure (Section 1R12)
05000529/2004005-02	NCV	Failure to Follow Operability Determination Procedure (Section 1R15)
05000530/2004005-03	NCV	Excessive RCS Drain Rates Used to Establish Midloop Conditions (Section 1R20)
05000528; 529; 530 /2004005-04,	NCV	Failure to Include Vents and Drains into Locked Valve Program (Section 1R22)
05000530/2004005-05	NCV	Failure to Follow the Operability Determination Process for a Degraded Condition (Section 1R22)
05000529/2004005-06	NCV	Failure to comply with high radiation area Tchnical Specification requirement (Section 2OS2)
05000529/2004005-07	NCV	Core Alterations with Less than Two Operable SRMs (Section 4OA3)

Closed

05000529/2003004-00	LER	Mode 3 Entry with an Auxiliary Feed Water Pump Inoperable (Section 4OA3)
05000529/2004001-00	LER	Steam Generator Tube Leak (Section 4OA3)
05000529/2003003-00	LER	Source Range Inoperable During Core Reload (Section 4OA3)
05000528; 529; 530/2004007-00	LER	Exceeding the Maximum Power Level Specified in Operating License Condition 2.C(1) (Section 4OA3)
05000528/2004012-008 05000529/2004012-008 05000530/2004012-008	URI	Unit 3, Low Pressure SI System In-Leakage (Section 4OA5)
2515/152	TI	RPV Lower Head Penetration Nozzles (Section 4OA5)
2515/153	TI	Reactor Containment Sump Blockage - NRC Bulletin 2003-1, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors" (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

In addition to the documents called out in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Section 1R01: Adverse Weather

Procedures

NUMBER	TITLE	REVISION
40OP-9ZZ17	Cold Weather Protection	26
40AO-9ZZ21	Acts of Nature	20

Miscellaneous

PM basis for Refueling Water Tank Temperature Elements, 1992

Section 1R04: Equipment Alignment

Procedures

NUMBER	TITLE	REVISION
40OP-9ZZ16	RCS Drain Operations	44
40OP-9ZZ20	Reduced Inventory Operations	6
40OP-9SI01	Shutdown Cooling Initiation	32

Section 1R12: Maintenance Effectiveness

Procedures

NUMBER	TITLE	REVISION
73ST-9XI33	HPSI Pump and Check Valve Full Flow Test	17

WOs

2714002

Section 1R13: Maintenance Risk assessment and Emergent Work Control

CRDRs

2753977

Section 1R15: Operability Evaluations

Procedures

NUMBER	TITLE	REVISION
40EP-9EO01	Standard Post Trip Actions	11
40EP-EO03	Loss of Coolant Accident	15
40EP-9EO05	Excess Steam Demand	14
40EP-9EO09	Functional Recovery	20

WOs

SWA 4463	00002668	00096603
00129843	00132279	00418653
00000776	00000147	00418142
00132176	00243426	

Miscellaneous

NUMBER	TITLE	DATED
	Magnetic Particle Examination Report 04-643, RPV Head	November 12, 2004
Westinghouse Letter LTR-SGDA-04-329,	Evaluation of Palo Verde Units 1 and 3 Two Missing Set Screws in the SG Feedwater Box	
10 CFR 50.59 Evaluation E-04-0016	Operability Determination 2722278 Compensatory Actions	Revision 1
EER 88-SI-077 EER 87-CH-080		
Calculation 13-MC-ZA-0203	Auxiliary Building HELB Analysis	Revision 2

Drawings

13-M018-00142	Control Schematic (Starting Sequence Control)

Section 1R17: Permanent Plant Modifications

CRDRs

2752688

Miscellaneous

Selection of NDE results for pressurizer heater sleeves installation

PMT results per TS 3.4.9 - 32ST-9RC01, “92 Day Pressurizer Heater Capacity Test,” November 21, 2004

Relief Request 23

Relief Request 30

Section 1R19: Postmaintenance Testing

Procedures

NUMBER	TITLE	REVISION
32MT-9PE01	18 Month Cleaning, Inspection, and Testing of the Class 1E Diesel Generator	10
73ST-9DG01	Class 1E Diesel Generator and Integrated Safeguards Test Train A	8 TAPA 8C

WOs

2716055	2728901
2742444	2759580
2644052	2759229

Section 1R20: Refueling and Outage Activities

Procedures

NUMBER	TITLE	REVISION
40OP-9ZZ16	RCS Drain Operations	44
40OP-9ZZ20	Reduced Inventory Operations	6
40OP-9SI01	Shutdown Cooling Initiation	32
40OP-9ZZ11	Mode Change Checklist	59
74DP-9CY04	Systems Chemistry Specification	29

CRDRs

2742453	2749302
2750148	2761655

Drawings

NUMBER	TITLE	REVISION
13-C-00A-008	Column Line Designation Key Plan	7

Miscellaneous

NUMBER	TITLE	DATED
Letter 054-03104-PJW/GJP	2004 Unit 3 Midloop Brief	September 17, 2004
EER 92-RC-023	Determination of Maximum Drain Rates for RCS	February 28, 1992

Tagging/Clearance Activities

Permit 105234, “Second RCS permit to de-energize pump, drain thrust bearing and NC piping”
Permit 110092, “1689 ½ Pipe Permit (Electric Only)”
Permit 109831, “Remove Vortex Breaker of Train ‘A’ Recherche Sump Suction Valve to support leak testing”
Permit 109832, “Remove Vortex Breaker of Train ‘B’ Recherche Sump Suction Valve to support leak testing”
Permit 108743, “1881-1 A Train ECCS Sump”
Permit 109671, “A Train SSC”
Permit 108098, “Install PWR System T-Mod U3"

Section 1R22: Surveillance Testing

CRDRs

2761657

WOs

TWO 02624146	2749296

Procedures

NUMBER	TITLE	REVISION
40OP-9DG01	Emergency Diesel Generator A	35
40AL-9DG01	Diesel Generator A Alarm Panel Responses	17

Section 2OS2: ALARA Planning and Controls (71121.02)

CRDRs

2644102	2691031	2744095
2665047	2695319	2745961
2683356	2695513	2746459
2689876	2700732	2747378
2690979	2708492	2748748
2690998	2713632	2749276

ALARA Committee Minutes

2003: December 2, December 5, and December 11
2004: February 20, February 26, March 3, March 10, April 14, May 24, and October 27

Audits and Self-Assessments

Post Refueling Outage ALARA Report for U1R11, April 3 - May 10, 2004
Review of High Noise END Utilization in U2R11, Self Assessment, January 22, 2004

Procedures

NUMBER	TITLE	REVISION
75DP-0RP01	RPV Program Overview	4
75DP-0RP03	ALARA Program Overview	2
75DP-0RP06	ALARA Committee	3
75DP-9RP01	Radiation Exposure and Access Control	6
75RP-9RP02	Radiation Exposure Permits	17
75RP-9RP10	Conduct of R.P.M. Operations,	13

Radiation Exposure Permits

1-3013A	1-3502E	3-3306F
1-3045B	2-6002A	3-3400B
1-3047A	3-3002F	3-3502G
1-3306E	3-3047A	

Shielding Requests

TOP Number C-120-11 TOP Number C-140-09

WOs

2601511	2658697
2601514	2684401
2601515	2704793
2601516	

Miscellaneous

Declared Pregnant Worker dose assessment for three workers
Exit transactions from the Radiologically Controlled Area greater than 100 mrem from September 24, 2003 through November 3, 2004

Section 4OA1: Performance Indicator Verification

Procedures

NUMBER	TITLE	REVISION
74DP-OLC01	RCS Activity Performance Indicator	3
93DP-OLC09	Data collection and SUBMITTALS Using INTO's Consolidated Data Entry System	3
74ST-9RC02	Reactor Coolant System Specific Activity Surveillance Test	9

Miscellaneous

Technical Specification 3.4.17

Section 4OA2: Identification and Resolution of Problems

Procedures

NUMBER	TITLE	REVISION
30DP-0RA01	Component Failure Trending	5
30DP-9WP02	Work Document Development and Control	35
90DP-0IP10	Condition Reporting	19
	PIV Coding and Trending Desk Instruction, September 2004	

Miscellaneous

Failure Data Trending Trend Codes and Values
Memorandum, "Significant Root Cause Evaluations," dated April 24, 2002

CRDRs

Trips/downpower	**2003/2004 NCVs**	**2003/2004 NCVs**	**2003/2004 LERs**
114845	**2004**	**2004 (cont)**	**2004**
114865	2599869	2717646	2592898
115788	2627031	2721947	2657316
116858	2639721	2746954	2682312
117886	2643347	2747353	2686919
118157	2657316	**2003**	2687292

2315636	2667948	2423603	2687507
2324452	2669486	2569888	2712226
2339519	2670023	2579110	2714809
2339523	2685303	2655298	**2003**
2391251	2686201	2656229	2577547
2405660	2686271		2589790
2414777	2686273		2590170
2430998	2686919		2592898
2447531	2687292		2594999
2566870	2695262		2595001
2594001	2697384		2613688
2614098	2699943		2623273
2623273	2704331		2624427
2624427	2707290		2636484
2627031	2709418		2654236
2643955	2711167		2654642
2669474	2711241		2722547
2685303	2711453		2726509
2687145	2711971		2733393
2707423	2715669		
2707578	2715709		
2714544	2715726		
2715659	2715731		
2715709	2715749		
2715727	2716019		
2716184	2716281		
2717298	2716521		
2721635	2716806		

Section 4OA5: Other Activities

Procedures

NUMBER	TITLE	REVISION
73TI-9ZZ78	Visual Examination for Leakage	5

Miscellaneous

Visual Examination Reports:

VT-04-673	VT-04-674	VT-04-675	VT-04-676
VT-04-677	VT-04-678	VT-04-679	VT-04-680
VT-04-682	VT-04-683	VT-04-726	VT-04-727
VT-04-728	VT-04-797	VT-04-798	VT-04-805
VT-04-761	VT-04-762	VT-04-763	VT-04-765

VT-04-729	VT-04-743	VT-04-746	VT-04-746
VT-04-796			

NUMBER	TITLE	REVISION
Calculation 13-M C-SI-309	Containment Sump Blockage	3

Nondestructive Examination Activities Reviewed

System/Line No/Component ID	Weld Number/Cat.	Exam Method
Safety Injection	13-10	VT-2
Safety Injection	9-10	VT-2
Pressurizer Spray	9-11	VT-2
Pressurizer Spray	11-11	VT-2
Pressurizer Spray	5-33	RT
Safety Injection	76-08	UT
Safety Injection	77-08	PT/UT
Safety Injection	77-16	UT
3PSGEL002	2608319-3	RT
3PSGEL002	2608319-4	MT/RT
SG-202-H-1	F-A/F1.20	VT-3
SG-42-H-15	F-A/F1.20	VT-3
SI-33-H-4	F-A/F1.20	VT-3
SI-105-H-E	F-A/F1.20	VT-3
SI-105-H-D	F-A/F1.20	VT-3
SI-105-H-C	F-A/F1.20	VT-3
SI-236-H-1	F-A/F1.20	VT-3
SI-105-H-B	F-A/F1.20	VT-3
SI-236-H-2	F-A/F1.20	VT-3
SI-236-H-3	F-A/F1.20	VT-3
SI-236-H-4	F-A/F1.20	VT-3

Reactor Vessel Head CEDM Penetration Records

Penetration No.	Exam Method
2	UT/ET
7	UT/ET
12	UT/ET
18	UT/ET
21	UT/ET
28	UT/ET
30	UT/ET
33	UT/ET
34	UT/ET
35	UT/ET
41	UT/ET
42	UT/ET
53	UT/ET
55	UT/ET
58	UT/ET

Acquisition, Analysis, and Examination Technique Specification Sheets

Palo Verde ACTS/ANTS	EPRI Examination Technique Specification Sheets
B1-A-70 Rev 3/B1-A-70 Rev 15	96004.1 R9, 96007.1 R10,96008.1 R13
R-2A-70 Rev 4/R2-A-70 Rev 9	96910.1 R7, 21409.R2, 21410.1 R3, 20510.1 R4, 20511.1 R6, 96703.1 R13
R3-A-70 Rev 1/R3-A-70 Rev 9	96910.1 R7, 21409.R2, 21410.1 R3, 20510.1 R4, 20511.1 R6, 96703.1 R13
R5-A-70 Rev 3/R5-A-70 Rev 9	96703.1 R13
R6-A-70 Rev 5/R6-A-70 Rev 8	99997.1, R7

Condition Report/Deficiency Request (CRDR)

2589740
2594999
2595001
2596461
2600110

Relief Requests

RR 23, “Request to use an ambient temperature automatic or machine GTAW temper bead process during modification of the Pressurizer heater sleeve (nozzles)”

RR 25, “Request for relaxation of First revised NRC Order EA-03-009, Section IV.C.(5)(b) Requirements for CEDM Nozzles”

Boric Acid Walkdown Evaluation

Interim 1 Disposition, DFWO 2593265, dated 3/30/03
Final Disposition, DFWO 2593265, dated 5/15/03

Work Orders

2608319, Feedwater to Steam Generator Pipe Replacement

Miscellaneous Documents

NRC Order EA-03-009, Establishing Interim Inspection Requirements For Reactor Pressure Vessel Heads At Pressurized Water Reactors, dated February 20, 2004

Report, Unit 3 Degradation Assessment, June 2004

Palo Verde Steam Generator Eddy Current Program Analysts Guidelines Training Manual, Revision 23

Report, Unit 3 Cycle 10, Condition Monitoring Evaluation, dated April 2003

Report, Unit 3 Operational Assessment (U3C11) Evaluation, May 2003 - October 2004

WCAP-16208-P, NDE Inspection Length For CE Steam Generator Tubesheet Region Explosive Expansions, Revision 0

LIST OF ACRONYMS

ALARA	as low as reasonably achievable
ASME	American Society of Mechanical Engineers
CAP	corrective action program
CEDM	control element drive mechanism
CFR	Code of Federal Regulations
CIV	containment isolation valve
CMC	core monitoring computer
COLSS	core operating limit supervisory systems
CRDR	condition report/discrepancy request
CS	containment spray
ECCS	emergency core cooling system
EDG	emergency diesel generator
EER	engineering evaluation request
EPRI	Electric Power Research Institute
GDC	general design criteria
LER	licensee event report
NCV	noncited violation
PI&R	problem identification and resolution
PIV	post indicator valve
PWR	pressurized water reactor
RCS	reactor coolant system
RPV	reactor pressure vessel
RWT	refueling water tank
SI	safety injection
SRM	startup range monitor
SSC	structure, system, and component
TI	temporary instruction
UFSAR	Updated Safety Analysis Report
WO	work order