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

February 6, 2007

Randall K. Edington
Senior Vice President, Nuclear
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SUBJECT: PALO VERDE NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000528/2006005, 05000529/2006005, AND 05000530/2006005

Dear Mr. Edington:

On December 31, 2006, the U.S. 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 4, 2007, 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.

The report documents six NRC identified findings and two self-revealing findings. Seven of these findings were evaluated under the risk significance determination process as having very low safety significance (Green). One finding was not suitable for evaluation under the significance determination process; however, it was determined to be of very low safety significance by NRC management review. Because of the very low safety significance of these violations and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations consistent with Section VI.A of the NRC Enforcement Policy. Two licensee identified violations, which were determined to be of very low safety significance, are listed in Section 4OA7 of this report. 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 the 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/

Troy W. Pruett, Chief
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Division of Reactor Projects

Dockets: 50-528
50-529
50-530

Licenses: NPF-41
NPF-51
NPF-74

Enclosure:
NRC Inspection Report 05000528/2006005, 05000529/2006005, and 05000530/2006005
w/Attachment: Supplemental Information

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SUNSI Review Completed: __TWP__ADAMS: √ Yes ☐ No Initials: __TWP____
√ Publicly Available ☐ Non-Publicly Available ☐ Sensitive √ Non-Sensitive

R:_REACTORS_PV\2006\PV2006-005RP-GGW.wpd

RIV:RI:DRP/D	SRI:DRP/D	SPE:DRP/D	C:DRS/EB2	C:DRS/PSB
JFMelfi	GGWarnick	GEWerner	LJSmith	MPShannon
E-TWP	E-TWP	/RA/	/RA/	/RA/
02/02/07	02/02/07	01/31/07	01/30/07	01/30/07
C:DRS/OB	C:DRS/EB1	C:DRP/D		
ATGody	WBJones	TWPruett		
/RA/	/RA/	/RA/		
01/29/07	01/30/07	02/06/07		

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528, 50-529, 50-530
Licenses:	NPF-41, NPF-51, NPF-74
Report:	05000528/2006005, 050000529/2006005, 05000530/2006005
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	October 1 through December 31, 2006
Inspectors:	P. Benvenuto, Resident Inspector, Project Branch D M. Chambers, Project Engineer (accompanying/trainee) R. Egli, Reactor Technology Instructor L. Ellershaw, PE, NRC Consultant M. Hay, Branch Chief, Project Branch C W. Johnson, NRC Contractor J. Josey, Resident Inspector, Project Branch E J. Melfi, Resident Inspector, Project Branch D E. Owen, Reactor Inspector, Engineering Branch 1 G. Warnick, Senior Resident Inspector, Project Branch D G. Werner, Senior Project Engineer, Project Branch D
Approved By:	Troy W. Pruett, Chief, Project Branch D Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000528/2006005, 05000529/2006005, 05000530/2006005; 10/01/06 - 12/31/06; Palo Verde Nuclear Generating Station, Units 1, 2, and 3; Integrated Res. & Reg. Rpt; Op. Eval., Perm. Plant Mods, Ident. & Res. of Problems, & Follow-up of Events and Notices of Enf. Discretion.

This report covered a 3-month period of inspection by resident inspectors, regional inspectors, and NRC contractors. The inspection identified eight noncited violations. 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. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified for the failure of maintenance personnel to use an adequate procedure for the repairs and restoration of control Valve 2, resulting in a reactor trip during main turbine control valve restoration. Specifically, on July 26, 2006, maintenance personnel used Procedure 40OP-9MT02, "Main Turbine," Revision 53, for performing repairs and restoring control Valve 2 in a way that was beyond the scope of the procedure. The use of the inadequate procedure resulted in a plant transient and reactor trip. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2913232.

  The finding is greater than minor because it would become a more significant safety concern if left uncorrected in that more significant consequences would occur if inadequate procedures are used for plant maintenance. The finding affected the initiating events cornerstone. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the initiating events cornerstone and did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. This finding has a crosscutting aspect in the area of human performance associated with work control because the licensee did not appropriately coordinate work activities by incorporating actions to address the impact of changes to the work scope of the maintenance procedure (Section 4OA3.1).

Cornerstone: Mitigating Systems

- Green. The inspectors identified a noncited violation of Technical Specification 5.4.1.a for the failure of maintenance and engineering personnel to follow Procedure 30DP-9WP11, "Scaffolding Instructions," Revision 13, and associated engineering specifications governing scaffold erection near safety-related components. Specifically, on September 13, 2006, inspectors identified three scaffolds that were within 2 inches of safety-related components. The scaffolding did not have an engineering evaluation in place, nor were there any documented records of engineering evaluations for any other scaffolding on site. Again on October 3, 2006, the inspectors identified two scaffolds that were directly attached to the fuel and auxiliary building essential air handling units, without the required evaluations. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Requests 2924707 and 2929770.

  The finding is greater than minor because it would become a more significant safety concern if left uncorrected in that improperly installed scaffolding could impact the availability of mitigating equipment. The finding affected the mitigating systems cornerstone. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it only affected the mitigating systems cornerstone, and all subsequent engineering evaluations determined that there was no adverse effect to mitigating equipment. This finding has a crosscutting aspect in the area of human performance associated with work control because the licensee did not appropriately coordinate work activities to keep personnel apprised of the operational impact of work activities. Additionally, this finding has a crosscutting aspect in the area of problem identification and resolution associated with corrective actions in that the licensee did not take appropriate corrective actions to address safety issues in a timely manner (Section 1R15.1).

- Green. The inspectors identified two examples of a noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," for the failure of engineering and operations personnel to adequately evaluate degraded and nonconforming conditions to support operability decision making as described in Procedure 40DP-9OP26, "Operability Determination and Functional Assessment." Specifically, on October 11, 2006, operations personnel did not evaluate the potential effects of the degraded condition of the nitrogen system piping on a containment isolation valves' ability to close. Additionally, on November 6, 2006, engineering personnel did not include the amount of fiberglass insulation tape found in the Unit 3 containment in the estimated quantity of tape in containment for the Unit 1 operability justification. These issues were entered into the licensee's corrective action program as Condition Report/Disposition Requests 2932103 and 2940354.

  The finding is greater than minor because it is associated with the equipment performance cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it only affected the mitigating systems cornerstone, and all subsequent operability evaluations determined that there was no adverse effect to mitigating equipment. This finding has a crosscutting aspect in the area of human performance associated with decision making because the licensee did not use conservative assumptions for operability decision making when evaluating degraded and nonconforming conditions (Section 1R15.2).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the improper control of design parameters for post accident monitoring instrumentation by operations personnel. Specifically, prior to November 22, 2006, operations personnel did not maintain the seismic qualification of post accident monitoring instrumentation, by pulling recorders out from the fully inserted position for extended periods. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2945259.

  The finding is greater than minor because it would become a more significant safety concern if left uncorrected in that safety-related equipment that is not maintained in a seismically qualified condition may not be available to perform its safety function under certain accident conditions. The finding affected the mitigating systems cornerstone. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it did not affect the loss or degradation of equipment specifically designed to mitigate a seismic event, and it did not involve the total loss of any safety function that contributes to external event initiated core damage accident sequences (Section 1R15.3).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure of the licensee to adequately evaluate and identify the cause for a degraded material condition associated with Unit 2 Valve SI-225 following a failure of the valve to fully close on November 30, 2000. Specifically, the licensee did not have any data to support their root cause evaluation and could not validate the failure mechanism that prevented Valve SI-225 from fully closing. The failure to identify the cause and implement corrective actions resulted in the failure of Valve SI-134 in October 2006 and the continued degradation of additional safety injection system check valves. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2942970.

  The finding is more than minor because it is associated with the equipment performance attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone and did not result in the actual loss of safety function to any component, train, or system. This finding has a crosscutting aspect in the area of problem identification and resolution because the licensee failed to thoroughly evaluate a problem that was known to exist since November 2000 (Section 4OA2).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," for the failure to promptly identify and correct a condition adverse to quality. Specifically, since 1992, the licensee failed to maintain procedures and written instructions in accordance with quality assurance program requirements, including, periodic procedural reviews and implementation of the procedure feedback process. These issues resulted in a significant number of deficient procedures and instructions not being corrected in a timely manner and not receiving adequate reviews. One example involved the failure to provide adequate instructions for mounting temperature element housings adversely affecting seismic qualifications required to protect the functionality of safety related equipment. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2952142.

  This finding is greater than minor because the failure to identify and correct deficient procedures, if left uncorrected, would become a more significant safety concern in that quality related systems, structures, and components could be adversely affected by implementing inadequate instructions. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it did not result in loss of operability per, "Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment." This finding involved problem identification and resolution crosscutting aspects associated with the failure to promptly identify and correct deficient procedures/instructions resulting in the potential to adversely affect quality related systems, structures, and components (Section 4OA2).

- Green. Two examples of a self-revealing noncited violation of Technical Specification 5.4.1.a were identified for the failure of operations personnel to properly implement procedures to ensure the correct configuration of equipment during plant evolutions. Specifically, twice on November 4, 2006, operations personnel failed to restore the containment spray system to standby operations for shutdown cooling per Procedures 73ST-9XI33, "HPSI Pump and Check Valve Full Flow Test," and 40ST-9SI09, "ECCS System leak Test," following surveillance testing to satisfy the entry conditions for Procedure 40OP-9SI01, "Shutdown Cooling Initiation." This issue was entered into the licensee's corrective action program as Condition Report/Disposition Request 2939686.

  The finding is greater than minor because it is associated with the configuration control cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination

Process," Checklist 3, and is determined to have very low safety significance because the finding did not result in an increase of the likelihood of a loss of decay heat removal due to failure of the system, nor did it degrade the ability of containment to remain intact following an accident. Additionally, the finding did not degrade the licensee's ability to terminate a leak path, add reactor coolant system inventory, recover decay heat removal once it is lost, or establish an alternate core cooling path. Lastly, the finding did not increase the likelihood of a loss of reactor coolant system inventory, or offsite power. This finding has a crosscutting aspect in the area of human performance associated with work control because the licensee did not appropriately coordinate work activities by communicating, coordinating, and cooperating with each other during surveillance testing activities (Section 4OA3).

Cornerstone: Barrier Integrity

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Criterion III, "Design Control," for the failure of engineering personnel to implement an adequate procedure for acceptance testing of the upgraded refueling equipment resulting in several malfunctions, including one that resulted in a fuel assembly contacting one of the storage baskets in the spent fuel pool at a higher than designed speed. Specifically, between October 8 and October 13, 2006, the site acceptance test procedures were not adequate to identify and prevent several malfunctions of the refueling equipment due to design and installation inadequacies of Design Modification Work Order 2778582. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Requests 2931991 and 2937420.

  The finding is greater than minor because it would become a more significant safety concern if left uncorrected in that refueling equipment malfunctions could result in damaged fuel. The finding affected the barrier integrity cornerstone. This finding cannot be evaluated by the significance determination process because Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," and Appendix G, "Shutdown Operations Significance Determination Process," do not apply to the spent fuel pool or the refueling pool. This finding is determined to be of very low safety significance by NRC management review because it was a deficiency that did not result in the actual degradation of spent fuel (Section 1R17).

B. Licensee-Identified Violations

Two 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. The violations and their corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period shutdown to replace the pressurizer heaters. The unit entered Mode 3 on October 5, 2006, then returned to Mode 5 to repair a safety-related check valve due to a failed surveillance test. The unit was restarted on October 15 and achieved essentially full power on October 18. The unit remained at essentially full power until October 21, when an automatic reactor trip occurred as a result of indication problems with the control element assemblies. The unit was restarted on October 22 and reached essentially full power on October 25 and remained there for the duration of the inspection period.

Unit 2 began the inspection period shutdown for refueling Outage 2R13. The outage was completed on November 14, 2006, and the unit returned to essentially full power on November 18, and remained there for the duration of the inspection period.

Unit 3 operated at essentially full power until October 19, 2006, when a manual reactor trip was initiated due to a loss of two condensate pumps. The unit was restarted on October 20, and reached essentially full power on October 22 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)

a. Inspection Scope

Readiness For Seasonal Susceptibilities

The inspectors completed a review of the licensee's readiness for seasonal susceptibilities involving extreme low temperatures. The inspectors: (1) reviewed plant procedures, the Updated Final Safety Analysis Report (UFSAR), and Technical Specifications (TSs) to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the two systems listed below to ensure that adverse weather protection features (heat tracing, space heaters, weatherized enclosures, temporary chillers, etc...) were sufficient to support operability, including the ability to perform safe shutdown functions; (3) evaluated operator staffing levels to ensure the licensee could 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.

- December 6, 2006, Units 1, 2, and 3, emergency core cooling system (ECCS)

- December 7, 2006, Units 1, 2, and 3, essential spray pond system

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed two samples.

Readiness For Impending Adverse Weather Conditions

On December 5, 2006, the inspectors completed a review of the licensee's readiness for impending adverse weather involving cold temperatures. The inspectors: (1) reviewed plant procedures, the UFSAR, and TSs to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the below listed system to ensure that adverse weather protection features (heat tracing, space heaters, weatherized enclosures, temporary chillers) were sufficient to support operability, including the ability to perform safe shutdown functions; (3) reviewed maintenance records to determine that applicable surveillance requirements were current before the anticipated cold temperatures developed; and (4) reviewed plant modifications, procedure revisions, and operator work arounds to determine if recent facility changes challenged plant operation.

- December 5, 2006, Units 1, 2, and 3, auxiliary feedwater (AFW) system

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

Partial Walkdown

The inspectors: (1) walked down portions of the three 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 licensee's UFSAR and CAP to ensure problems were being identified and corrected.

- October 9, 2006, Unit 1, shutdown cooling (SDC) Train B during reduced inventory operations

- October 23, 2006, Unit 2, fuel pool cooling, essential chilled water, and nuclear cooling water Train B while Train A was out of service for preplanned maintenance

- November 3, 2006. Unit 2, SDC Train B during midloop while Train A was in operation

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed three samples.

Complete Walkdown

The inspectors: (1) reviewed plant procedures, drawings, the UFSAR, TSs, and vendor manuals to determine the correct alignment of the emergency diesel generator (EDG) system; (2) reviewed outstanding design issues, operator work arounds, and UFSAR documents to determine if open issues affected the functionality of the EDG system; and (3) verified that the licensee was identifying and resolving equipment alignment problems.

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

Quarterly Inspection

The inspectors walked down the eight below listed plant areas to assess the material condition of active and passive fire protection features and their operational lineup and readiness. 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 and that access to manual actuators was unobstructed; (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 that the compensatory measures were commensurate with the significance of the deficiency; and (7) reviewed the UFSAR to determine if the licensee identified and corrected fire protection problems.

- October 3, 2006, Unit 3, condensate storage pump house and tunnel

- October 16, 2006, Unit 1, condensate storage pump house and tunnel
- October 17, 2006, Unit 2, containment building, all elevations
- October 27, 2006, Units 1, 2, and 3, gas turbine Generators 1 and 2
- November 3, 2006, Unit 1, main steam support structure, all elevations
- November 9, 2006, Unit 2, main steam support structure, all elevations
- December 7, 2006, Unit 2, auxiliary building, 100 foot, 120 foot, and 140 foot elevations
- December 8, 2006, Unit 2, auxiliary building, 40 foot, 52 foot, 70 foot, and 88 foot elevations

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed eight samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

Semi-annual Internal Flooding

The inspectors: (1) reviewed the UFSAR, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving internal flooding; (2) reviewed the UFSAR and CAP to determine if the licensee identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of (a) sump pumps, (b) level alarm circuits, (c) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down the below listed areas to verify the adequacy of: (a) equipment seals located below the floodline, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

- November 3, 2006, Units 1, 2, and 3, AFW pump room Trains A and B

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

Inspection Procedure 71111.08 requires four samples sizes, as identified in Sections 02.01, 02.02, 02.03, and 02.04.

02.01 Performance of Nondestructive Examination Activities Other Than Steam Generator Tube Inspections, Pressurized Water Reactor Vessel Upper Head Penetration Inspections, Boric Acid Corrosion Control

a. Inspection Scope

The inspection procedure requires the review of nondestructive examination activities consisting of two or three different types (i.e., volumetric, surface, or visual). The inspectors observed the performance of ultrasonic examinations (volumetric) on 3 steam generator blowdown line welds, and partial observation of ultrasonic examinations on 2 AFW line welds, including sizing and resolution of indications. The inspectors also observed magnetic particle examinations (surface) on 12 steam generator support welds and examined radiographic film and reports (volumetric) on 4 safety injection (SI) line welds. The table below identifies the above examinations, which were conducted using three methods and two different examination types.

System/ Component	**Identity**	**Examination Type**	**Examination Method**
Steam Generator Blowdown Line	Pipe to Valve Welds 02-065-041, -042, and -043	Volumetric	Ultrasonic
Auxiliary Feedwater Line	Pipe to Elbow Welds 02-059-023 and -024	Volumetric	Ultrasonic
Safety Injection Line	Pipe to Pipe Welds 2865107-1 and -4	Volumetric	Radiography
Safety Injection Line	Min-flow line pipe to pipe welds 2932479-1 (R1) and -2	Volumetric	Radiography
Steam Generator Component Support	Component Support SG-5-H-1 (consisting of 12 welds)	Surface	Magnetic Particle

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

During review of each examination, the inspectors verified that appropriate nondestructive examination procedures were used, examinations and conditions were as specified in the procedure, and test instrumentation or equipment was properly calibrated and within the allowable calibration period. The inspectors also verified the nondestructive examination certifications of the personnel who performed the above volumetric, surface, and visual examinations. Finally, the inspectors observed that indications identified during the ultrasonic, radiographic, and magnetic particle examinations were dispositioned in accordance with the ASME qualified nondestructive examination procedures used to perform the examinations.

The inspection procedure requires 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. The inspectors were informed that no indications exceeding ASME Code allowables were known to be in service.

The inspection procedure further requires 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 verified through record review and observation that welding performed on a SI system vent valve and replacement of a portion of the Train B high pressure safety injection (HPSI) min-flow line was performed in accordance with Section XI of the 1992 Edition and 1992 Addenda of the ASME Code. This included review of welding material issue slips to establish that the appropriate welding materials had been used and verification that the welding procedure specifications (WPS-8MN-GTAW/SMAW, Revision 15 and WPS-73WP-0ZZ07, Revision 11, respectively) had been properly qualified.

The inspectors completed the one sample required by Section 02.01.

b. Findings

No findings of significance were identified.

02.02 Reactor Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

The inspection requirements for this section parallel the inspection requirement steps in Section 02.01. The inspectors reviewed records of completed nondestructive examinations, including the eddy current and ultrasonic examination data analyses process used on the reactor vessel upper head penetrations.

The inspectors reviewed eddy current examination C-scans and reports (combination volumetric and surface) and ultrasonic examination C-scans and reports (volumetric) on 10 reactor pressure vessel upper head penetration Control Element Drive Mechanism Nozzles 12, 21, 24, 26, 38, 59, 69, 77, 83, 87, and the eddy current examination C-scan and report on the head vent line.

Additionally, the nondestructive examination procedures used to perform the above examinations were reviewed to assure that they were consistent with ASME Code requirements, and the equipment and calibration requirements were appropriately identified and demonstrated. The nondestructive examination records were also reviewed to verify that 100 percent of the required inspection coverage was achieved on the identified penetration nozzles.

The inspectors verified that the nondestructive activities were performed in accordance with the requirements of NRC Order EA-03-009.

The nondestructive examinations did not reveal any defects. A total of 19 indications were identified in the 97 penetration nozzles, all of which were dispositioned in accordance with the licensee's qualified procedures and in accordance with ASME Code acceptance criteria parameters.

The inspectors determined through discussions with licensee personnel that welding repairs were going to be implemented (subsequent to this inspection) on the head vent line penetration. The inspectors observed the head vent line mockup and demonstration of welding qualification activities. The specified welding procedure specification (WPS 3-43/52 TB MC-GTAW-N638, Revision 15) and its procedure qualification records (PQR 694A and PQR 742) were reviewed to assure that welding procedure specification qualification requirements of Section IX of the ASME Code were complied with.

The inspectors completed the one sample required by Section 02.02.

b. Findings

No findings of significance were identified.

02.03 Boric Acid Corrosion Control Inspection Activities (Pressurized Water Reactors)

a. Inspection Scope

The inspectors evaluated the implementation of the licensee's boric acid corrosion control program for monitoring degradation of those systems that could be deleteriously affected by boric acid corrosion.

The inspection procedure requires review of a sample of boric acid corrosion control walkdown visual examination activities through either direct observation or record review. The inspectors reviewed the documentation associated with the licensee's boric acid corrosion control walkdown, as specified in Procedure 70TI-9ZCO1, "Boric Acid Corrosion Prevention Program," Revision 5. Samples of documented visual inspection records of inspection walkdowns performed on components and equipment during October 2006 were reviewed by the inspectors.

Additionally, the inspectors performed independent observations of piping containing boric acid during walkdowns of the containment building and the auxiliary building.

The inspection procedure requires verification that visual inspections emphasize locations where boric acid leaks can cause degradation of safety significant components. The inspectors verified through direct observation and program/record review that the licensee's boric acid corrosion control inspection efforts are directed towards locations where boric acid leaks can cause degradation of safety-related components.

The inspection procedure requires both a review of one to three engineering evaluations performed for boric acid leaks found on reactor coolant system (RCS) piping and components, and one to three corrective actions performed for identified boric acid leaks. There were no applicable condition report disposition requests (CRDRs) generated since the last inspection period that required formal engineering evaluations, (e.g., that resulted in a separate design or structural engineering analysis to determine continued operability). The inspectors reviewed CRDRs (see Attachment), documenting minor valve packing leaks on valves in the SI system. The planned corrective actions were adequate in each case.

The inspectors completed the one sample required by Section 02.03.

b. Findings

No findings of significance were identified.

02.04 Steam Generator Tube Inspection Activities

a. 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 licensee's report "Unit 2 Cycle 12 Condition Monitoring Evaluation," dated May 6, 2005, with Appendix update for Refueling Outage 2R13, 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 remaining screening parameters were consistent with the EPRI 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 inspector-reviewed acquisition 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. This refueling outage marked the completion of the second operating cycle for the Unit 2 steam generators (i.e., they were replaced in 2004). During the last refueling outage steam generator tube inspections, the only flaws identified were wear type indications. At the completion of the NRC inspection, approximately 60 percent of the steam generator tubes had been inspected, and thus far, the number of identified indications fell within the range of prediction. Importantly, no new damage mechanisms had been identified during this inspection.

The inspection procedure specified confirmation that the steam generator tube eddy current test scope and expansion criteria meet TS requirements, EPRI guidelines, and commitments made to the NRC. The inspectors evaluated the recommended steam generator tube eddy current test scope established by TS requirements and the Palo Verde Nuclear Generating Station Degradation Assessment Report. The inspectors compared the recommended test scope to the actual test scope and found that the licensee had accounted for all known flaws and had, as a minimum, established a test scope that met TS requirements, EPRI guidelines, and commitments made to the NRC. The scope of the licensee's eddy current examinations of tubes in both steam generators included:

- A full length bobbin examination of 100 percent of inservice tubes,
- Straight section bobbin of 206 tubes 08C TEC and 206 tubes 08H TEC, each steam generator,
- Special interest - approximately 151 total tubes in both the cold legs and hot legs, and upper bend areas, and
- Verification of 25 possible pluggable defects

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. To date, the eddy current test results had not identified any new degradation mechanisms.

The inspection procedure requires confirmation that the licensee inspected all areas of potential degradation, especially areas that 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 requires verification that repair processes being used were approved in the TSs. At the time of this inspection, it was estimated that approximately 14 tubes in Steam Generator 21 would be plugged and approximately

17 tubes in Steam Generator 22 would be plugged. The inspectors verified that the mechanical expansion plugging process to be used was an NRC-approved repair process.

The inspection procedure also requires confirmation of adherence to the TS plugging limit, unless alternate repair criteria have been approved. The inspection procedure further requires 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 TS plugging limits were being adhered to (i.e., 40 percent maximum through-wall indication).

If steam generator leakage greater than 3 gallons per day was identified during operations or during post shutdown visual inspections of the tubesheet face, the inspection procedure requires 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 assessments because this condition did not exist.

The inspection procedure requires 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 tests performed on the tubes in Steam Generators 21 and 22. 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 a review of site-specific qualifications of the techniques being used. These are identified in the Attachment.

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 perform an evaluation of the potential effects of inaccessible object migration and tube fretting damage. At the time of this inspection, the licensee had identified four possible loose parts in Steam Generator 21 and eight in Steam Generator 22. Thus far, foreign object search and retrieval (FOSAR) had retrieved what appeared to be small remnants of flexitallic gasket material in Steam Generator 22. This would be a continuing process based on what was detected as the inspections proceeded. Evaluations, thus far, had determined that the possible loose parts had created very minor wear conditions, and the affected tubes would be preventatively plugged.

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 completed the one sample required by Section 02.04.

b. Findings

No findings of significance were identified.

02.05 Identification and Resolution of Problems

a. Inspection Scope

The inspection procedure requires review of a sample of problems associated with inservice inspections documented by the licensee in the CAP for appropriateness of the corrective actions.

The inspectors reviewed nine condition report disposition requests which dealt with inservice inspection activities and found that the corrective actions were appropriate. From this review the inspectors concluded that the licensee had an appropriate threshold for entering issues into the CAP and has procedures that direct a root cause evaluation when necessary. The licensee also had an effective program for applying industry operating experience.

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. In addition, the inspectors reviewed the written exam and exam results for training Cycle NLR06-05, Week 4. The following training scenarios were reviewed:

- December 7, 2006, Scenario NLRO6S05 02 00, "Blackout," Revision Date November 1, 2006

- December 8, 2006, Scenario SES 0-09-D-07, "Inadvertent AFAS, SGTL, SGTR w/o HPSI (MVAC-1)," Revision Date July 20, 2005

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the five below listed 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 the TSs.

- October 16, 2006, Unit 2, inspections of large bore (>12 inches diameter) Borg-Warner (BW) safety-related check valves during refueling Outage 2R13

- December 15, 2006, Units 1, 2, and 3, General Electric Magne-Blast circuit breaker failures on June 14, 2004, February 6, 2005, and October 27, 2006

- December 2006, Units 2 and 3, atmospheric dump valve nitrogen backup system pressure drop test failures

- December 2006, Units 1, 2, and 3, chemical and volume control system Valve CH-500 seat leakage

- December 2006, Units 1, 2, and 3, chemical and volume control system letdown backpressure control valves erratic pressure control

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed five samples.

b. Findings

See Section 4OA2 for findings of significance identified.

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

a. Inspection Scope

Risk Assessment and Management of Risk

The inspectors reviewed the two 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.

- October 2, 2006, Unit 1, inspection of K1 field shorting contactor metal actuator arm adjustment via work order (WO) 2919666

- December 11, 2006, Unit 2, evaluation of the risk management action levels during scheduled maintenance on AFW Pump AFA-P01 discharge isolation Valve 2JAFCH0033

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed two 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 UFSAR to determine if the licensee identified and corrected risk assessment and emergent work control problems.

- December 12 to 13, 2006, Unit 1, leak identified on fuel delivery holder for 5L jerk pump on EDG Train A as described in work mechanism (WM) 2948764 and Palo Verde Action Request (PVAR) 2948762

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and night orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the UFSAR 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 TSs; (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.

- September 13 to October 3, 2006, Unit 1, scaffolding erected over the essential fuel building ventilation system Trains A and B without appropriate engineering evaluation

- October 13, 2006, Unit 1, pin hole leak in the miniflow recirculation line of HPSI pump Train B, immediately downstream Valve SIB-UV-667

- October 13, 2006, Units 1, 2, and 3, evaluation of stiff condition identified in the disc assembly for BW safety-related check valves and its operability impact

- October 16, 2006, Unit 1, failure, degradation, and ultimate replacement of all pressurizer heaters

- October 25, 2006, Unit 1, high pressure nitrogen isolation Valve 1JGAAUV1 failure as a result of metal debris obstructing the seat

- November 6, 2006, Units 1, 2, and 3, degraded Anaconda flexible conduits and nonconforming repair methods identified in containment

- November 22, 2006, Units 1, 2, and 3, degraded condition of the EDGs due to fuel leaks on the high pressure jerk pump discharge line

- November 22, 2006, Units 1, 2, and 3, configuration control and seismic qualification of the post accident monitor recorders in the control room

- November 29, 2006, Unit 3, degraded drain line on EDG Train B exhaust line as documented in CRDR 2944955

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed nine samples.

b. Findings

.1 Scaffolding Erected Near Safety-Related Equipment

Introduction. The inspectors identified a Green noncited violation (NCV) of TS 5.4.1.a for the failure of maintenance and engineering personnel to follow procedures and associated engineering specifications governing scaffold erection near safety-related components.

Description. On September 13, 2006, during a tour of the Unit 2 auxiliary building, the inspectors identified inadequate clearances between three seismic scaffold installations and safety-related shutdown cooling components. Procedure 30DP-9WP11, "Scaffolding Instructions," Revision 13, Step 3.2.6, stated that, "All scaffolding erected/modified should conform to applicable specifications, regulations and standards. Deviations from these standards shall be evaluated by Civil Engineering." One of the specifications listed in Step 3.2.6 was Specification 13-CN-380, "Installation Manual for Category IX & Non-Seismic Scaffolding." Specification 13-CN-380 includes Engineering Design Change (EDC) 2000-00463, which stated that, "Palo Verde has utilized a minimum spatial clearance of 2 inches from the edge of pipe or pipe insulation to any fixed obstruction, allowing for potential thermal expansion and dynamic movements of the piping system. Lesser clearances will require specific documented engineering evaluations."

The scaffolding identified by the inspectors did not meet the clearance requirement and had not received an engineering evaluation. The licensee subsequently inspected all seismic scaffolding and identified additional examples where the scaffolding specifications were not met. The inspectors were informed that engineering evaluations determined that the existing clearances were adequate for the three structures identified by the inspectors and the additional examples identified by the licensee. However, when the inspectors requested a copy of the engineering evaluations, the licensee explained that the engineering evaluations were not documented.

On October 3, 2006, during a tour of the Unit 1 fuel building, the inspectors observed scaffolding installed on top of the fuel and auxiliary building essential air handling units. The scaffolding had the appropriate tags attached, and the tags were labeled "yes" under engineering evaluation. This indicated that the scaffolding had received an evaluation by civil engineering to ensure its seismic adequacy. The inspectors requested either a copy of the evaluation or to speak with the engineer that performed the evaluation to verify the type of considerations that went into the evaluation. Following the request, the licensee could not produce any documentation, nor could they find a civil engineer that could remember having made the evaluation. Further investigation revealed that the carpenters that built the scaffold did not understand the requirements of Procedure 30DP-9WP11, "Scaffolding Instructions," and did not seek an evaluation by civil engineering. Instead the carpenters requested verbal permission over the phone from a ventilation system engineer. The ventilation engineer did not realize his verbal permission was being used to validate the seismic qualification of the scaffolding and the structural impact to adjacent equipment. Therefore, the carpenters built the scaffolding and marked the tags "yes" under engineering evaluation, without talking with the civil engineer in charge of evaluating seismic structures. Subsequently, appropriate engineering evaluations were performed and documented for the scaffolding.

Two similar NCVs were previously identified by the inspectors. On January 28, 2000, NCV 05000528; 05000529; 05000530/2000003-02 was identified due to inadequate scaffolding clearances and lack of specifications. The licensee entered the issue into the CAP as CRDR 116095. As a corrective action, the licensee initiated EDC 2000-00463 to establish the scaffold specification clearance requirement of 2 inches. On February 25, 2005, NRC inspectors identified several instances of scaffolding not satisfying the 2 inches clearance requirement from safety-related piping. This resulted in NCV 05000528; 05000529; 05000530/2005002-02. The licensee initiated CRDR 2779469 to provide additional training and to ensure that the carpenters were aware of the requirements found in EDC 2000-00463. However, the corrective actions implemented were not effective. The clearance criteria was not adequately communicated to the carpenters resulting in instances where a required engineering evaluation was not performed. Additionally, contrary to the guidance found in EDC 2000-00463, no documentation was maintained for any of the scaffolding engineering evaluations performed.

As a consequence of the repeated performance deficiencies, the licensee conducted an assessment of the entire scaffolding program, including the process used to perform the engineering evaluations. The assessment resulted in a revision to Procedure 30DP-9WP11, to clarify the requirement to obtain an engineering evaluation from civil engineering when clearance requirements could not be maintained. Additionally, the licensee enhanced the scaffolding program to require engineering personnel to document the evaluations in writing and to attach them to a PVAR. The licensee also reviewed all scaffolding throughout the site that required an engineering evaluation and documented the evaluation in writing. The licensee also plans to develop training for employees and contractors to clarify the requirements of Procedure 30DP-9WP11.

Analysis. The performance deficiency associated with this finding involved maintenance and engineering personnel not following procedures. The finding is greater than minor because it would become a more significant safety concern if left uncorrected in that improperly installed scaffolding could impact the availability of mitigating equipment. The finding affected the mitigating systems cornerstone. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it only affected the mitigating systems cornerstone, and all subsequent engineering evaluations determined that there was no adverse effect to mitigating equipment. This finding has a crosscutting aspect in the area of human performance associated with work control because the licensee did not appropriately coordinate work activities to keep personnel apprised of the operational impact of work activities. Additionally, this finding has a crosscutting aspect in the area of problem identification and resolution associated with corrective actions in that the licensee did not take appropriate corrective actions to address safety issues in a timely manner.

Enforcement. TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Appendix A, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors" of Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)," dated February 1978. Regulatory Guide 1.33, Appendix A, Section 9a, requires maintenance that can affect safety-related equipment be properly preplanned and performed in accordance with written instructions appropriate to the circumstances. Procedure 30DP-9WP11, "Scaffolding Instructions," Revision 13, required that scaffolding be erected with a minimum clearance of 2 inches from safety-related components and that any lesser clearances receive a specific documented engineering evaluation. Contrary to this, on September 13, 2006, and again in October 3, 2006, maintenance personnel built scaffolding not meeting the 2 inches minimum clearance requirement, and engineering personnel did not perform or maintain records of the evaluations. Specifically, on September 13, 2006, inspectors identified three scaffolds that were within 2 inches of safety-related components. The scaffolding did not have an engineering evaluation in place, nor were there any documented engineering evaluations for any other scaffolding on site. Again on October 3, 2006, the inspectors identified two scaffolds that were directly attached to the fuel and auxiliary building essential air handling units, without the required evaluations. Because the finding is of very low safety significance and has been entered into the CAP as CRDRs 2924707 and 2929770, this violation is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy: NCV 05000528; 05000529; 05000530/2005002-01, "Scaffolding Erected with Inadequate Clearances and No Engineering Evaluation."

.2 <u>Operability Determination Procedure Adherence</u>

Introduction. The inspectors identified two examples of a Green NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," for the failure of engineering and operations personnel to adequately evaluate degraded and nonconforming conditions to support operability decision making.

Description. The inspectors identified two examples where the assessment of operability did not meet the NRC's expectations as delineated in Regulatory Issue Summary 2005-20 or follow the operability determination (OD) process in Procedure 40DP-9OP26, "Operability Determination and Functional Assessment," Revision 17.

The first example involved the failure to use the OD process to provide a reasonable expectation that a containment isolation valve was operable when a degraded condition called into question its operability. Specifically, on October 11, 2006, the licensee pressurized the safety injection tanks (SITs) using the high pressure nitrogen system in preparation for Mode 3 entry. After completing the activity, the switch for containment isolation Valve 1JGAAUV0001 was taken to the close position, but the close indication did not illuminate on control room Panel B07. The operators checked the position of Valve 1JGAAUV0001, and while the Emergency Response Facility Data Acquisition and Data System indicated closed, the Safety Equipment Status System indicated the valve was open. The valve was declared inoperable and after isolating the high pressure nitrogen line, a local leak rate test was performed per Procedure 73ST-9CL01, "Containment Leakage Type "B" and "C" Testing," Revision 30. The valve failed the local leak rate test, indicating that it was not fully seated. The licensee took action to disassemble Valve 1JGAAUV0001 per WO 2936149. Maintenance personnel identified a small piece of metal approximately 1 inch long and 1/16 inch wide lodged between the disc and the seat. The piece of metal was rusted and was spiral shaped. After removing the foreign object, the licensee evaluated the condition as an isolated incident with no transportability concerns.

The inspectors raised questions concerning the rusted condition of the piece of metal found in Valve 1JGAAUV0001 and the condition of the rest of the nitrogen system piping. The licensee explained that the nitrogen system was a clean system, that this was an isolated event, and that there was no more debris inside the pipes that could impact valve operability. Not satisfied with the answers, the inspectors further questioned the basis for the licensee's conclusions. The inspectors also questioned the need for an operability evaluation to provide a reasonable expectation of operability, including the consideration of potential effects of the degraded condition of the nitrogen system piping on the containment isolation valves' ability to close. The licensee disagreed with the inspectors and did not perform an OD; however, they did enter the issue into the CAP as CRDR 2932103 to perform further evaluation. The licensee did agree to perform a boroscope inspection of the nitrogen line at a future time to verify their conclusion that no more debris was inside the piping.

One month later, on November 10, 2006, the licensee performed a boroscope inspection of the nitrogen line and discovered another piece of metal that appeared to be wedged in the inlet socket weld of Valve 1JGAAUV0001. The additional piece of metal appeared to be very similar to the one found on October 11, 2006. The licensee was unsuccessful in removing the piece of metal, but was able to vacuum out some dust and rust in the pipe that was believed to have come from the piece of metal. The licensee issued deficiency work order (DFWO) 2941382 to justify a conditional release (Use-As-Is) disposition. A final rework disposition will be issued when the pipe is disassembled and the piece of metal is removed from the system. Based on the operating history of the valve, the licensee concluded that the piece of metal has probably been in this location since construction and considers it to be an isolated incident.

The second example involved the adequacy of the operability assessment for a degraded and nonconforming condition associated with Anaconda flexible conduits and the repair methods used inside the containment building. Specifically, the licensee entered the OD process on November 6, 2006, when several containment component conduits in Unit 2 were found to have cracks and/or splits in their Sealtite flexible conduit outer sheeting insulation. Scotch electrical tape (Type 33) and fiberglass insulation tape have been used as methods to repair the degraded conduit insulation. Application of Scotch electrical tape inside containment was approved per Equipment Change Evaluation ECE-QQ-A143, however, fiberglass insulation tape has not been evaluated for use inside containment. The OD process was entered since the condition called into question the ability of the conduit to perform its intended function and to assess the impact to the ECCS recirculation sump due to sump strainer blockage from the tape debris source.

The licensee performed a walkdown of the Unit 2 containment to identify SSCs affected by the condition and identified locations (impingement zones) where the tape used for conduit insulation repair could credibly be damaged, dislodged, and transported to the containment sumps. The licensee estimated approximately 27 square feet of the Scotch electrical tape in the impingement zones as a result of the Unit 2 walkdown. The licensee did not identify any of the non-evaluated fiberglass insulation tape used as a repair method. Pending results of similar inspections in Units 1 and 3, the licensee assumed that a similar number and type of SSCs were affected, and assumed that all of the tape, from each impingement zone, would be transported to the containment sumps. Additionally, a 10 percent margin was added, for further conservatism, such that a value of 30 square feet was used in the basis for the operability evaluation performed for those units. All tape in the impingement zones of interest in Unit 2 was removed.

The licensee's basis for reasonable expectation of operabilty was that the sum of the estimated quantity of tape located in the impingement zones (30 square feet) and the amount of loose debris accounted for in Units 1 and 3 (21.25 square feet and 21.00 square feet, respectively) was less than the allowed limit (66 square feet).

During the inspectors' review of the OD, it was noted that fiberglass insulation tape was used as a conduit insulation repair method was identified in the Unit 3 containment in May 2006, during refueling Outage 3R12. Work Order 2892349 identified the components where the tape was located and initiated action to remove the non-evaluated tape. The inspectors questioned the licensee why only the results from the Unit 2 walkdown were included in the assumption used to assess the operability impact to the Unit 1 containment sump, since only Scotch electrical tape was identified. The inspectors determined that it was possible that fiberglass insulation tape had also been used as a repair method in the Unit 1 containment based on the Unit 3 findings in May 2006. Further, the inspectors observed that a more conservative assumption would have been to include the amount of fiberglass insulation tape found in Unit 3 containment in the estimated quantity of tape for Unit 1. The licensee agreed with the inspectors' observations and reevaluated the condition for Unit 1.

The prompt OD was revised on December 9, 2006, to include results of the reevaluation. Review of WO 2892349 identified an estimated 28.57 square feet of fiberglass tape that was located and removed from the Unit 3 containment. Because of the nature of the fiberglass tape and uncertainty of the effectiveness of the binders present in the tape, the licensee conservatively assumed that 100 percent of the tape would be transported to the containment sump. This was irrespective of its initial location, effects of long term radiation exposure, and the effects of post-accident environmental conditions. Additionally, the licensee determined that a more realistic assumption for the estimated amount of Scotch electrical tape in Units 1 and 3 would be to conservatively estimate that 50 percent of the tape could be in any one impingement zone. The assumption used in Revision 0 of the prompt OD, where all of the Scotch electrical tape from all of the impingement zones was transported to the containment sumps, was unrealistic and overly conservative. The reevaluation determined that there was a reasonable expectation of operabilty for Unit 1 since the sum of the estimated quantity of tape located in the impingement zones (43 square feet) and the amount of loose debris accounted for in Unit 1 (21.25 square feet) was less than the allowed limit (66 square feet).

<u>Analysis</u>. The failure to adequately implement the OD process was a performance deficiency. The finding is greater than minor because it is associated with the equipment performance cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it only affected the mitigating systems cornerstone, and all subsequent operability evaluations determined that there was no adverse effect to mitigating equipment. This finding has a crosscutting aspect in the area of human performance associated with decision making because the licensee did not use conservative assumptions for operability decision making when evaluating degraded and nonconforming conditions.

<u>Enforcement</u>. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," requires that activities affecting quality shall be prescribed by instructions, procedures, or drawings, and shall be accomplished in accordance with those instructions, procedures, and drawings. The assessment of operability of safety-related equipment needed to mitigate accidents was an activity affecting quality, and was implemented by Procedure 40DP-9OP26, "Operability Determination and Functional Assessment," Revision 17. Contrary to the above, on October 11, 2006, and again on November 6, 2006, engineering and operations personnel failed to adequately evaluate degraded and nonconforming conditions to support operability decision making as described in Procedure 40DP-9OP26. Specifically, operations personnel did not perform an OD to provide a reasonable expectation of operability, including the consideration of potential effects of the degraded condition of the nitrogen system piping on a containment isolation valves' ability to close. Additionally, engineering personnel used non-conservative assumptions by not including the amount of fiberglass insulation tape found in the Unit 3 containment in the estimated quantity of tape for the Unit 1 operability

justification. Because the finding is of very low safety significance and has been entered into the CAP as CRDRs 2932103 and 2940354, this violation is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy: NCV 05000528/2006005-02, "Two Examples of Failure to Properly Implement Operability Determination Process."

.3 Seismic Qualification of Recording Instruments

Introduction. The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the improper control of design parameters for post accident monitoring instrumentation by operations personnel.

Description. On November 22, 2006, the inspectors were conducting a control room walk down and observed that several recording instruments had been pulled out half way from the control panels. The operators explained that this was used as a reminder when the recorders were running out of paper. The recorders were maintained in this position until the roll of paper was replaced, and then pushed into the fully inserted position. The inspectors discussed with the operators a recent event where a nuclear power plant tripped after a piece of the recorder was dropped on top of a control panel while the roll of paper was being replaced. Additionally, the inspectors asked the operators if there were any safety or seismic concerns with the recorders being maintained in the pulled out position. After consulting with engineering, operations personnel concluded that the recorders were seismically qualified only in the fully inserted position. All the recorders were fully inserted and a night order was written to alert operations personnel.

On November 29, 2006, the inspectors asked operations personnel if the issue with the recorders had been entered into the CAP. The licensee replied that the issue had not been entered in the CAP and initiated a CRDR. While reviewing the CRDR, the inspectors noted that the evaluation stated that the condition did not impact TSs. However, many of the recorders in question were required for post accident monitoring and were listed in the UFSAR, in Table 1.8-1, "PVNGS Compliance With Regulatory Guide 1.97 (Revision 2) Requirements." Table 1.8-1 stated that these recorders were Seismic Class I, which applied to components that must remain functional in the event of a safe shutdown earthquake. Maintaining the recorders in a position in which they were not seismically qualified would constitute a non-compliance with the UFSAR requirements. Additionally, the post accident monitoring instrumentation is required by TS 3.3.10. Therefore, the inspectors concluded that the issue with the recorders affected TS components, and that the licensee's evaluation was lacking.

The inspectors concluded that the licensee had maintained the practice of pulling out the recorders for quite some time. This involved safety and non-safety related recorders, that were pulled out and maintained in the unqualified position for unspecified periods of time, with no controls or procedures in place. With no records of which instruments, and for how long they were kept in the pulled out position, the inspectors concluded that the operators had this practice to remind themselves of the need to replace the paper, and that the recorders were likely not maintained in this position for more than a few hours at a time.

Analysis. The performance deficiency associated with this finding involved operations personnel not maintaining proper control of design parameters for post accident monitoring instrumentation. The finding is greater than minor because it would become a more significant safety concern if left uncorrected in that safety-related equipment that is not maintained in a seismically qualified condition may not be available to perform its safety function under certain accident conditions. The finding affected the mitigating systems cornerstone. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it did not affect the loss or degradation of equipment specifically designed to mitigate a seismic event, and it did not involve the total loss of any safety function that contributes to external event initiated core damage accident sequences.

Enforcement. 10 CFR Part 50, Criterion III, "Design Control," states in part that, measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in 50.2 and as specified in the license application, for those SSC to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. Contrary to this, prior to November 22, 2006, operations personnel did not establish measures to assure that applicable regulatory requirements concerning the seismic qualifications of post accident monitoring instrumentation were maintained. Specifically, operations personnel did not maintain the seismic qualification of post accident monitoring instrumentation, by pulling recorders out from the fully inserted position, and keeping them half way out from the control panels when the paper was running out. Because the finding is of very low safety significance and has been entered into the CAP as CRDR 2945259, this violation is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy: NCV 05000528; 05000529; 05000530/2006005-03, "Failure to Maintain Seismic Qualification of Post Accident Monitoring Instrumentation."

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

Annual Review

The inspectors reviewed key affected parameters associated with energy needs, materials/replacement components, timing, heat removal, control signals, equipment protection from hazards, operations, flowpaths, pressure boundary, ventilation 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 did not impair emergency/abnormal operating procedure actions, key safety functions, or operator response to a loss of key safety functions; (2) post-modification testing maintained 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.

- October 31, 2006, Unit 2, installation and acceptance testing of refueling equipment upgrades per design modification work order (DMWO) 2778582

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

Introduction. The inspectors identified a Green NCV of 10 CFR Part 50, Criterion III, "Design Control," for the failure of engineering personnel to implement an adequate procedure for the acceptance testing of the upgraded refueling equipment resulting in several malfunctions, including one that resulted in a fuel assembly contacting one of the storage baskets in the spent fuel pool at a higher than designed speed.

Description. On October 8, 2006, the licensee completed acceptance testing for the upgraded refueling equipment in Unit 2, and commenced core offload for refueling Outage 2R13. Numerous equipment issues associated with the modified equipment occurred during the core offload.

On October 9, 2006, at 1:12 am, the operators suspended fuel movement when an unexpected trolley drift occurred while lowering the refueling machine hoist box. Maintenance personnel inspected the equipment and found minor backlash in the trolley drive train, which was determined not to be excessive. Fuel movement was resumed following an evaluation of the condition.

On October 9, 2006, at 4:14 pm, fuel movement was suspended due to a drift from the vertical position by the transfer machine upender in the containment building. The licensee's troubleshooting determined that the anomaly with the upender was due to an incorrect timing of the hydraulic pump and solenoid valves, which is controlled by the transfer machine computer. Maintenance personnel loaded a new software version in order to fix the condition. However, retest of the transfer machine showed that the upender, after being taken to auto transfer, would go down to the horizontal position and then back up to the vertical position without performing the transfer function. Unable to correct the problem the licensee loaded the original software and decided to continue moving fuel in the manual mode until a software upgrade could be installed to support automatic operations.

On October 10, 2006, at 6:31 pm, fuel movement was suspended due to a motion encoder error of the spent fuel machine, which caused spurious alarms. The licensee concluded that the error was due to the sensitivity of the new equipment. The error was reset and fuel movement continued.

On October 11, 2006, at 12:45 pm, fuel movement was suspended to correct the hydraulic pressure valve settings in the fuel transfer machine in the fuel building. The licensee concluded that the pressure valve settings were incorrect and the valves were opening too soon, reducing pressure in the hydraulic system and causing some of the upender drift. Unable to correct the problem with the upender drift, the licensee continued fuel movement.

On October 11, 2006, at 12:13 am, while lowering fuel Assembly P2P216 into the spent fuel pool Location FF14, the operators reported that they received an underload, followed by an overload, and finally a maximum overload indication. It was also reported that the spent fuel handling machine (SFHM) slightly shook. Evaluation of these indications concluded that the fuel assembly had contacted the top of the fuel basket at a higher than designed speed. Fuel movement was immediately stopped, and conditions were reported to the shift manager and fuels supervision. A "Fuel Handling Event Recovery Checklist," per Procedure 40DP-9OP02, "Conduct of Shift Operations," Revision 36, was initiated and Abnormal Operating Procedure 40AO-9ZZ22, "Fuel Damage," Revision 9, was entered since the entry condition of an, "Unintentional contact of an irradiated fuel assembly with any solid structure," was met. The upgraded SFHM was designed to operate the hoist such that as the fuel assembly entered the fuel basket region, the machine automatically slowed down from 40 feet per minute to five feet per minute to ensure a smooth transition of the fuel into the spent fuel basket. This transition was supposed to occur three inches above the fuel basket and clear three inches below the fuel basket. The licensee's investigation determined that an incorrect elevation setting on the modified equipment resulted in the transition not occurring until the fuel assembly was slightly above or at the fuel basket elevation. This resulted in the fuel assembly entering the fuel basket region prior to making the full transition to slow speed as designed. Consequently, the operator did not have adequate time to position the assembly as the fuel assembly entered the basket to minimize the potential for interference. Fuel Assembly P2P216 was inspected following this event and no damage was observed.

On October 13, 2006, at 2:15 am, the fuel machine vendor representative loaded an incorrect software version while attempting to correct the recurring problems with the upender in the containment building. The licensee re-installed the original software and continued with fuel movement. A licensee investigation after the completion of fuel movement concluded that the problems with the drifting of the upender were mis-diagnosed and were actually due to the presence of air in the hydraulic lines. Additionally, the licensee concluded that the pressure valve settings that had to be corrected, were the result of a portion of the acceptance testing which manipulated the pressure valves and left them in the incorrect setting.

<u>Analysis</u>. The performance deficiency associated with this finding involved the failure of engineering personnel to implement an adequate procedure for the acceptance testing of the upgraded refueling equipment resulting in several malfunctions and a fuel assembly contacting one of the storage baskets in the spent fuel pool at a higher than designed speed. The finding is greater than minor because it would become a more significant safety concern if left uncorrected in that refueling equipment malfunctions could result in damaged fuel. The finding affected the barrier integrity cornerstone. This finding cannot be evaluated by the significance determination process because Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," and Appendix G, "Shutdown Operations Significance Determination Process," do not apply to the spent fuel pool or the refueling pool. This finding is determined to be of very low safety significance by NRC management review because it was a deficiency that did not result in the actual degradation of spent fuel.

Enforcement. 10 CFR Part 50, Criterion III, "Design Control," states, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to this, the site acceptance test procedures were not adequate to identify and prevent several malfunctions of the refueling equipment due to design and installation inadequacies of DMWO 2778582. Specifically, between October 8 and 13, 2006, refueling equipment experienced several malfunctions, including one that resulted in a fuel assembly contacting one of the storage baskets in the spent fuel pool at a higher than designed speed. Because the finding is of very low safety significance and has been entered into the CAP as CRDRs 2931991 and 2937420, this violation is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy: NCV 05000529/2006005-04, "Inadequate Acceptance Testing for the Upgraded Refueling Equipment."

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 re-aligned, and deficiencies during testing were documented. The inspectors also reviewed the UFSAR to determine if the licensee identified and corrected problems related to postmaintenance testing.

- October 10, 2006, Unit 1, retest of low pressure safety injection (LPSI) pump discharge check Valve SIE-V134 following maintenance per WO 28864185

- December 1, 2006, Unit 3, retest of EDG Train B following maintenance per Procedure 40ST-9DG02, "Diesel Generator B Test," Revision 31

- December 11, 2006, Unit 2, stroke test of AFW pump discharge isolation Valve 2JAFCHV0033 per Procedure 73ST-9XI05, "AF and CT Valves - Inservice Test," Revision 21, following maintenance

- December 13, 2006, Unit 1, retest of EDG Train A following replacement of 5L jerk pump per WM 2948764

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

Unit 1 Short Notice Outage for Pressurizer Heater Replacement

The inspectors reviewed the following risk significant outage activities to verify defense in depth commensurate with the outage risk control plan, compliance with the TSs, and adherence to commitments in response to Generic Letter 88-17, "Loss of Decay Heat Removal:" (1) the risk control plan; (2) RCS instrumentation; (3) electrical power; (4) decay heat removal; (5) inventory control; (6) reactivity control; (7) containment closure; (8) reduced inventory conditions; (9) heatup and cooldown activities; (10) restart activities; and (11) licensee identification and implementation of appropriate corrective actions associated with outage activities. The inspectors' containment inspections included observations of the containment sump for damage and debris; and supports, braces, and snubbers for evidence of excessive stress, water hammer, or aging.

Documents reviewed by the inspectors are listed in the attachment.

Refueling Outage 2R13

The inspectors reviewed the following risk significant refueling items or outage activities to verify defense in depth commensurate with the outage risk control plan, compliance with the TSs, and adherence to commitments in response to Generic Letter 88-17, "Loss of Decay Heat Removal:" (1) the risk control plan; (2) tagging/clearance activities; (3) RCS instrumentation; (4) electrical power; (5) decay heat removal; (6) spent fuel pool cooling; (7) inventory control; (8) reactivity control; (9) containment closure; (10) reduced inventory or mid-loop conditions; (11) refueling activities; (12) heatup and cooldown activities; (13) restart activities; and (14) licensee identification and implementation of appropriate corrective actions associated with refueling and outage activities. The inspectors' containment inspections included observations of the containment sump for damage and debris; and supports, braces, and snubbers for evidence of excessive stress, water hammer, or aging.

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the UFSAR, procedure requirements, and TSs to ensure that the seven below listed surveillance activities demonstrated that the SSCs 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 to demonstrate TS 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 17, 2006, Unit 1, inservice test of Valves SIB-UV-200 and SIB-UV-446 in accordance with Procedure "Train B LPSI and HP Check Valves - Inservice Test," Revision 14

- October 17, 2006, Unit 1, inservice test of containment spray (CS) pump Train B in accordance with Procedure 73ST-9SI06, "Containment Spray Pumps and Check Valves - Inservice Test," Revision 21

- October 23, 2006, Unit 2, local leak rate testing of containment Penetration 7 per Procedure 73ST-9CL01, "Containment Leakage Type 'B' and 'C' Testing," Revision 30, Section 8.2

- October 31, 2006, Unit 2, Procedure 73ST-9DG01, "Class 1E Diesel Generator and Integrated Safeguards Test, Train A," Revision 11, Section 8.2

- November 21, 2006, Unit 2, inservice test of HPSI pump Train A in accordance with Procedure 73ST-9SI10, "HPSI Pump Miniflow - Inservice Test," Revision 33

- November 30, 2006, Unit 3, chemistry sampling and analysis for essential spray pond Trains A and B

- December 21, 2006, Units 1, 2, and 3, station blackout gas turbine Generator 1 loaded run per Procedure 55OP-0GT01, "Gas Turbine Generator #1 Operating Instructions," Revision 45

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed seven samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the UFSAR, plant drawings, procedure requirements, and TSs to ensure that the below listed temporary modification was properly implemented. The inspectors: (1) verified that the modification did not have an effect on system operability/availability; (2) verified that the installation was consistent with modification documents; (3) ensured that the post-installation test results were satisfactory and that the impact of the temporary modification on permanently installed SSCs were supported by the test; (4) verified that the modification was identified on control room drawings and that appropriate identification tags were placed on the affected drawings; and (5) verified that appropriate safety evaluations were completed. The inspectors verified that the licensee identified and implemented any needed corrective actions associated with temporary modifications.

- December 15, 2006, Unit 1, Temporary Modification 2947993, "Installation of Monitoring Instrumentation on Inverter Train C as Part of Diagnostic Activities"

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

The inspectors performed a daily screening of items entered into the licensee's CAP. This assessment was accomplished by reviewing daily summary reports for CRDRs and WMs, and attending corrective action review and work control meetings. The inspectors: (1) verified that equipment, human performance, and program issues were being identified by the licensee at an appropriate threshold and that the issues were entered into the CAP; (2) verified that corrective actions were commensurate with the significance of the issue; and (3) identified conditions that might warrant additional follow-up through other baseline inspection procedures.

.2 Detailed Review of Unit 1 Safety Injection Check Valve SI-134 Failure

a. Inspection Scope

In addition to the routine review, the inspectors performed an in-depth review of the failure of Unit 1 Check Valve SI-134 to fully close. The inspectors completed the following during the review of the licensee's actions: (1) developed a complete scope of the failures of all Palo Verde BW safety-related check valves, with special emphasis on the large bore valves (>12 inches diameter) to fully close; (2) reviewed the extent of condition determination for this condition (current and prior check valve failures) and whether the licensee's actions were comprehensive; (3) reviewed the licensee's determination for the cause of the check valve binding and independently verify key assumptions and facts; (4) determined if the licensee's current and prior root cause analysis and corrective actions have addressed the extent of condition for problems with the BW safety-related check valves; (5) determined if the TSs were met when the check valve failed; (6) reviewed and assessed the effectiveness of corrective actions for current and past similar failures; (7) collected data as necessary to support a risk analysis; (8) reviewed industry operating experience related to BW check valves and ensured the licensee had incorporated the operating experience into the maintenance and testing programs for the check valves; and (9) determined if this issue has generic implications to other nuclear facilities.

Documents reviewed by the inspectors are listed in the attachment.

b. Background of Check Valve SI-134 and Similar Large Bore Check Valve Failures

The licensee has experienced two failures of large bore check valves (≥12 inches) to fully close. The first failure occurred in November 2000 on a 14 inch check valve (Unit 2 SI-225, SIT 2B outlet check valve). The failure of this valve was determined to be a lack of preventive maintenance activities to prevent the accumulation of contaminants around the spherical bearing and hinge pin. The most recent failure occurred on October 5, 2006, on a 12 inch check valve (Unit 1 SI-134, LPSI pump discharge check valve). For this check valve failure, the licensee made a decision to suspend heatup and cooled down the plant in order to perform a detailed disassembly and inspection of the Valve SI-134 internals (see attached drawing and parts description).

During the disassembly of Valve SI-134, the licensee found contaminants between the spherical bearing and the swing arm spherical bearing housing. The licensee analyzed the contaminates and determined that it consisted of normal reactor coolant materials. In addition, the licensee identified wear marks on the inside of the swing arm spherical bearing housing and the outside of the spherical bearing; excessive weld buildup on the stem to disc weld that interfered with the flush fit of the spherical bearing to the disc; galling between the contact area of the spherical bearing and the stem/disc weld; the spherical bearing installed backwards (manufacturer installation error); loose disc stem to swing arm hold down nut; and stem thread indentations on the inside of the spherical bearing. The licensee's interim root cause analysis determined that the failure to fully close was due to a combination of accumulation of contaminants in the spherical bearing/swing arm assembly and wear on the associated moving parts. In addition, since March 2002, the licensee identified15 instances of binding or freedom of movement concerns for the BW valve disc assembly. Palo Verde has 24 large bore check valves, with only four other nuclear plants (Catawba Nuclear Station, Oconee Nuclear Station, Perry Nuclear Power Plant, and St. Lucie Nuclear Plant) having similar sized check valves.

c. Palo Verde BW Check Valve History (Timeline)

Date	Event	Document	Response	Comments
10/86	Licensee response to industry significant operating events on check valve failures	Procedure 73DP-0XI02 Rev 0, "Check Valve Predictive Maintenance and Monitoring Program"	Procedure 73DP-0XI02 "Check Valve Predictive Maintenance and Monitoring Program," Rev 0, was created.	This procedure was issued to address industry significant operating events on check valve failure concerns that were not covered by the licensee's inservice test plan.
6/9/88	4" BW check valve, 2PSIBV405, "not seating"	WO298551	Valve 2SI405 was overhauled on 6/9/88 to correct the "valve not seating." The disc was found damaged. The records do not indicate if the disc was stuck open. On 5/15/98 this valve failed due to improper vertical alignment. Valve 2SI405 failed again, on 10/23/00 due to the disc cocked in the seat.	In 2000, CRDR 232280 investigated the repeat failures of Valve 2PSIBV405. CRDR 232280 referenced numerous missed opportunities between 1988 and 2000 to prevent these type of failures in BW check valves.
8/89	NRC Information Notice (IN) 1989-062: "Malfunction of Borg-Warner Pressure Seal Bonnet Check Valves Caused by Vertical Misalignment of Disk" was issued.	IN 89-62	Engineering Action Request (EAR) 89-1931 was issued on 1/26/1990 with incorrect conclusions on the licensee's applicability to IN 89-62. This was documented in CRDR 232280 when investigating the failure of 4" BW Valve 2PSIBV405 in 2000.	NCV 50-529/2001003-05 was issued due to ineffective corrective actions following the failure of Valve 2PSIBV405. Note that this was a check valve sticking open failure (disc tilting into seat) described in the 2/18/93 BW (CFRN)-9301 Part 21.

Date	Event	Document	Response	Comments
1/23/90	Comanche Peak BW check valve swing arm failures were documented in NRC Information Notice	NRC IN 90-03, "Malfunction of Borg Warner bolted bonnet Check valves Caused by Failure of the Swing Arm"	Engineering Evaluation Request (EER) 9-PV-0015 performed fracture analysis of check valve swing arms, modeled probabilistic risk assessment on core damage due to postulated check valve failures, provided acceptance criteria for porosity/linear indications on swing arms, and determined these failures were applicable to all BW check valves.	Eleven of the 136 susceptible BW check valve swing arms were inspected for crack indications in the 1990 refueling outage with no indications. No additional BW check valve inspections were scheduled for this failure until additional indications were found on check valve swing arms on 4/13/96 and 10/8/1998.
1/26/90	EAR 89-1931 was issued in response to 8/1998 IN 89-62.	EAR 89-1931	EAR 89-1931 stated, "…no action required…vendor manuals adequate…" EAR 89-1931 incorrectly credited existing procedural steps to verify horizontal alignment but did not consider the vertical misalignment issue.	CRDR 232280 on 2000 failures of 4" BW Valve 2PSIBV405 (disc tilting into seat) stated, "This was a missed opportunity to identify misalignment problems and enhance the valve maintenance instructions."
7/92	NRC IN 89-62 was re-evaluated following two failures of 4" BW SI check valves in 1992.	CRDR 920412 on BW Technical Alert 8909-77-001	The licensee initiated Procedure 73ST-9ZZ17, "Borg Warner Check Valve Assembly and Disassembly," Rev 0, to address site maintenance errors with BW check valve assembly. This also incorporated the BW 6/2/1992 alert on the issue of vertical misalignments. However, the inspection frequency, governed by another procedure, did not include all susceptible BW check valves.	NRC Inspection Report 50-528/98-14 identified apparent violations related to the 1998 failures of BW check valves 1PSIA-V404 and 2PSIA-V405 to close. The valve failures were similar to the failures described in the alert, though for model valves not identified by BW.

Date	Event	Document	Response	Comments
2/21/93	BW Part 21 on Model 77710 check valves disc tilting into seat (sticking open)	Borg Warner, Part 21 Notification Reference No. CFRN-9301	The licensee initially screened CFRN-9301 as not applicable since the licensee did not have the exact model valve referenced by CFRN-9301.	This Part 21 described BW check valve failing to fully close because of close tilt. From 1993 through 2000, the licensee expanded inspections for these types of failures in other BW check valves only after the failures occurred in differing models and sizes.
2/26/95	20" BW Check Valve 2PCHBV305 failed backleakage test.	CRDR 250097	The apparent cause was determined to be excessive gap between the arm and disk due to the fillet weld on the base of disc stud. Disc tilting into the seat indications were found during disassembly and repair.	Transportability (generic) issues not addressed by the licensee. The failure of the 20" valve was the same failure mode (disc tilting into the seat) as the 4" valves identified in the CFRN-9301 Part 21.
4/13/96	The 12" BW Check Valve 2PSIEV114 was found with a cracked hinge arm.	CRDR 960760	Corrective actions added hinge arm inspections for linear indications to Model 77790 series check valve inspections	The valve inspection scope of the initial 1/23/1990 response to IN 90-03 was inadequate because the licensee did not find this indication earlier.
10/19/96	20" BW Check Valve, 1PSIAV201, failed during ECCS leak surveillance test.	CRDR 160256	The apparent cause investigation found excessive gap between arm and disk. Disc in the seat indications were found during disassembly.	This 20" valve failure was subject to the same failure mode as the 4" valve identified in the CFRN-9301 Part 21.
5/19/98	4" BW Check valve, 2PSIAV405, backleakage problems	CRDR 53692	Repaired valve	NRC IR 50-528/98-14 identified apparent violations related to 1998 failures of BW check Valves 1PSIA-V404 and 2PSIA-V405 to close. These failures were similar to the failures described in the Part 21, though for valve models not identified by BW.

Date	Event	Document	Response	Comments
4/10/98	4" BW check Valve 1PSIAV404, backleakage problems	CRDR 35599 CRDR 45514 CRDR 1-8-0238	Incorrect vertical alignment was found and corrected on 6/10/98. The root cause of the failure was inadequate maintenance instructions (lack of vertical alignment detail) prior to 11/1994.	The CRDR identified configuration control problems related to incorrect spacers being installed that resulted in the incorrect vertical alignment.
7/29/98	BW check valve assembly and disassembly procedure was revised to check "play" in disc stud/swing arm.	Procedure 73ST-9ZZ17, "Borg Warner Check Valve Assembly and Disassembly," Rev 6	CRDR 1-8-0238 corrective actions included changes to the vertical alignment instructions to include valve drawings specifying locations where vertical alignment measurements were to be taken. Disc tilt values were taken for engineering information only.	Further refinements were taken to address the disc tilting into the seat concerns with BW check valves raised by the 1993 CFRN-9301 Part 21 and subsequent check valve problems.
9/1/98	BW check valve assembly and disassembly procedure was revised to incorporate measurements of play in the disc stud swing arm and record the "Tilted Value."	Procedure 73ST-9ZZ17, "Borg Warner Check Valve Assembly and Disassembly, " Rev 7	Additional CRDR 1-8-0238 corrective actions included an acceptance valve for disc tilt measurements.	Further refinements were taken to address the disc tilting into the seat concerns with BW check valves raised by the 1993 CFRN-9301 Part 21 and subsequent check valve problems from 1993 to 1998. The BW inspection population did not include all susceptible BW safety-related check valves.
9/23/98	Check valve predictive maintenance and monitoring program was revised to add checks for disc stud welds and play in the disc stud/swing arm on BW check valves.	Procedure 73DP-0X103, "Check Valve Predictive Maintenance and Monitoring Program," Rev 1	This information is from CRDR 2930774. Procedures 73ST-9ZZ17 and 73DP-OX103 were modified to control and document the BW check valve inspections and maintenance. New inspection points were added to specifically address checking for uneven stud welds and for play in the disc stud/swing arm.	Both of these conditions could result in the disc tilting into the seat. The BW check valves inspected were limited to a small number of the total population. Approximately 10 BW check valve back leakage failures were documented in the CRDRs between 1995 and 1998 that are not specifically listed in this table.

Date	Event	Document	Response	Comments
10/8/98	12" check Valve 3PSIEV144 found with cracked hinge arm.	CRDR 981636	By 7/28/99, the licensee had inspected 90 of the 126 suspect valves with only 2 hinge arm rejects found. Based on the small number of rejects found, the licensee determined no special inspection plan was needed, since the normal check valve inspection schedule would be adequate to monitor for hinge arm indications.	The 1/23/1990 check valve inspection scope response to IN 90-03 was inadequate to find this indication in 1990. Since 7/28/99, the licensee has inspected 34 of the remaining 36 check valve hinge arms with no crack indications found. Of the remaining two valves, 1PSIEV124 is scheduled to be inspected in the next Unit 1 outage, 1R13 and 2PCHAV177 is being moved into the periodic 12 year inspection Group C; but is not yet scheduled.
10/27/00	4" BW check Valve 2PSIBV405, failed its surveillance test.	CRDR 2332280 LER 2000-005-01	The apparent cause investigation found excessive freedom of movement due an excessive weld on the disc stud. This resulted in the check valve sticking open with its disc in the seat.	Valve SI-405, had previously failed in 1988. The 1993 BW Part 21, the 1995 20" Valve CH-305 failure and the 1996 20" Valve SI-201 failure all concerned varied sizes/models of BW check valves sticking open due to the disc tilting into the seat. At that time the licensee had not included preventive measures for the entire susceptible BW check valve population.
11/3/00	14" BW Valve 2PSIEV225 failed surveillance test during U3R10.	CRDR 2335098 LER 2000-006-01	The licensee found the root cause to be binding due to a lack of maintenance which allowed debris accumulation between the hinge arm and bearing. The licensee checked three more valves in U3R10 as a corrective action to address the extent of condition.	Subsequent valve inspections from 11/3/2000 through 11/2006 found 15 BW check valves with hinge arm/bearing binding without any documented disassembly and inspection of the hinge arm/spherical bearing.

Date	Event	Document	Response	Comments
5/21/02	Predictive maintenance and monitoring program was revised to increase BW check valve inspections.	Procedure 73DP-0X103, "Check Valve Predictive Maintenance and Monitoring Program," Rev 5	CRDR 2480940 was initiated in response to the Valve SI-225 failure. All BW SIT discharge and RCS loop valves were moved from Group D (random test group) to Group C (12 year test group) and added all check valves with a CLOSED safety function into Procedure 73DP-0X103.	At that time the licensee had no requirement for documenting the disassembly and inspection of the binding hinge arm/spherical bearing. This 5/2002 revision was a corrective action from the 11/2000 failure of Valve 2PSIEV225.
9/21/05	Predictive maintenance and monitoring program was revised to increase the BW check valve inspection frequency.	Procedure 73DP-0X103, Revision 9	This change moved BW 12" check valves from Group D (random test group) to Group C (12 year test group).	No requirement for documenting the disassembly and inspection of the binding hinge arm/bearing was required, despite 15 rejects due to binding documented from 10/2002 to 11/2006.
10/8/06	12" BW Check Valve 1PSIEV134, failed due to binding.	WO 28864185	A programmatic requirement to disassemble and inspect binding hinge arm/spherical bearings is being considered as part of the on-going root cause investigation.	Hinge arm and bearing was disassembled. A root cause investigation was initiated. The root cause investigation was hampered due to 14 previous hinge arm/bearing binding issues where the licensee did not disassemble and determine the cause for binding.

d. Findings and Observations

Introduction. The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure of the licensee to adequately evaluate and identify the cause for a degraded material condition associated with Unit 2 Valve SI-225 following a failure of the valve to fully close on November 30, 2000.

Description. The inspectors determined that the licensee had numerous opportunities to disassemble and inspect the check valve spherical bearings/swing arms (and other internal parts) with freedom of movement issues, but did not collect any data that could have been used to develop insights into the previous failure of Valve SI-225 or the current failure of Valve SI-134. Without the supporting information from the 15 check valves with freedom of movement deficiencies, the current root cause investigation postulated failure mechanism could not be validated. Based on inspection data, it does appear that the failure mechanism takes greater than 20 years to manifest itself; therefore, if the valves are properly rebuilt and restored to original condition, additional failures should not occur for many years. During interviews and a review of work documents, the inspectors determined that the licensee has inspected many of the original valves and reinstalled them without any cleaning or refurbishment to the suspected components.

Palo Verde has appropriately incorporated all industry operating experience and Part 21 information associated with BW check valves into their maintenance, testing, and surveillance programs. The licensee's initial corrective actions were focused on a very limited set of valves even though the internal construction of the components were essentially identical with the exception of the size of the components. This often resulted in failures of different size/model number check valves before the extent of condition encompassed all of the similarly constructed check valves (see the timeline above).

On November 30, 2000, with Unit 2 in Mode 3 and the SDC system secured and removed from service, operations personnel declared HPSI Train B inoperable while the system was being used to borate through the cold leg injection lines. During performance of this evolution, operations personnel noted that SIT 2B level and pressure were increasing because of back-leakage through the SIT 2B outlet check Valve SI-225. The licensee determined that this condition had the potential to affect HPSI Train A and cause injection flow to be diverted through Valve SI-225, resulting in both trains of HPSI being declared inoperable.

The inspectors noted that CRDR 2335098 indicated that the licensee identified the probable direct cause for the failure of Valve SI-225 to fully close as binding of the spherical bearing resulting from a buildup of contaminants on and around the spherical bearing. The identified root cause was a lack of preventative maintenance (PM) activities for the SIT discharge check valves which resulted in an unacceptable buildup of contaminants on the spherical bearing and hinge arm joint.

The inspectors determined that the licensee did not disassemble Valve SI-225 at the time of failure, but had instead conducted troubleshooting in accordance with an approved engineering plan to restore Valve SI-225 to an operable condition. This troubleshooting included forward flowing the valve while performing mechanical agitation on the valve body. This caused the valve to fully close and the licensee successfully performed the leak test of the valve. CRDR 2335098 included an action to inspect Valve SI-225. This inspection occurred approximately one year after the failure. The inspectors determined that the licensee did not disassemble and inspect the spherical bearing, despite discovering valve stiffness in the area of the spherical bearing. Instead, station personnel cleaned/decontaminated the area of the spherical bearing and lubricated the bearing with neolube, at which time the bearing operated smoothly and the determination was made that the valve internals were satisfactory and reinstalled. The inspectors determined that the use of neolube was not indicative of actual plant conditions and not representative of the operating environment. In addition, the licensee did not find or analyze any contaminates as part of this inspection activity.

The inspectors determined that no further disassembly and inspection of Valve SI-225 was performed to determine the cause of Valve SI-225 to fail to fully close in 2000. The inspectors also determined that there were multiple chances for the licensee to perform a disassembly and inspection of similar valves that had shown signs of stiffness in the spherical bearing, but no inspections were performed. Therefore, the inspectors determined that the licensee failed to identify the cause of a significant condition adverse to quality involving the failure of Valve SI-225 to close.

Analysis. The performance deficiency associated with this finding was the licensee's failure to perform an adequate root cause analysis, which resulted in the failure to identify and correct a significant condition adverse to quality. The finding is more than minor because it is associated with the equipment performance attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the mitigating systems cornerstone and did not result in the actual loss of safety function to any component, train, or system. This finding has a crosscutting aspect in the area of problem identification and resolution because the licensee failed to thoroughly evaluate a problem that was known to exist since November 2000. Since this time, the licensee has identified numerous valves with stiffness and one additional valve that failed to fully close in October 2006. With the exception of the most recent case, the internals were replaced and the cause never determined.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that for significant conditions adverse to quality, measures shall assure that the cause of the condition is determined. Contrary to the above, the licensee failed to adequately evaluate a significant condition adverse to quality and to determine the cause of the failure of Valve SI-225 that occurred on November 30, 2000. The failure to adequately evaluate the extent of condition associated with the failure of Unit 2 Valve SI-225 and implement prompt corrective actions resulted in a similar failure of Unit 1 Valve SI-134 on October 5, 2006. Because this finding is of very low safety significance and has been entered into the CAP as CRDR 2942970, this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy: NCV 05000529/2006005-05, "Failure to Perform an Adequate Root Cause Analysis for Valve SI-225."

.3 Review of Procedure Change Process

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed a review of the licensee's corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspector's review nominally considered the six-month period of June through December of 2006, although some examples expanded beyond those dates when the scope of the trend warranted. Corrective actions associated with a sample of the issues identified in the licensee's trend reports were reviewed for adequacy.

b. Findings and Observations

Introduction: The inspector's identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to promptly identify and correct a condition adverse to quality. The condition adverse to quality involved maintaining procedures and written instructions in accordance with quality assurance program requirements, including, periodic procedural reviews and implementation of the procedure feedback process. These deficiencies resulted in a significant number of deficient procedures and instructions not being corrected in a timely manner and not receiving adequate reviews.

Description: The inspectors noted that CRDR 2947749 identified seven potential maintenance instructions classified as WSL's (work scope library) that contained deficiencies associated with referencing the use of incorrect vendor technical manuals, instrument setpoint and uncertainty calculations, instrument accuracy requirements, and other deficiencies. The inspectors noted that the licensee had a group of procedures and instructions that were maintained as quality documents that were indexed in the site Nuclear Administrative and Technical Manual (NATM). The site WSL's were not part of the NATM process and therefore the licensee did not maintain quality controls for these instructions. The inspectors were informed by licensee personnel that a population of maintenance procedures were turned into WSL's for various reasons, including to reduce the burden associated with maintaining these quality related documents. The inspectors noted that the population of maintenance quality related WSL's was approximately 10,000. In the Instrumentation and Control Division, the total population of WSL's was 7,765, of which only 33 percent had ever received a periodic review.

The inspectors reviewed Nuclear Assurance Department (NAD) audits and noted that since 1992, NAD had consistently identified problems related to the quality assurance controls for maintaining procedures and instructions. Audit 96-013-03 documented, "The timely completion of periodic reviews continues to be a problem. Late periodic reviews for quality related procedures were identified during NAD Audits 92-008 and 94-006 and continue to be a problem in 1996." In 1997 the licensee received a license amendment that extended the periodic procedure review requirements provided alternative means were established to ensure review of these procedures prior to use. Additionally, periodic audits to satisfy regulatory requirements and commitments included assessments of a representative sample of related procedures to validate that the procedures were acceptable for use and that the procedure review and revision process was being effectively implemented. The inspectors noted that the licensee utilized a procedure feedback process as a mechanism for the procedure user to identify and communicate changes needed for deficient procedures. The inspectors noted that the licensee had a significant backlog of unaddressed procedure feedback forms. Additionally, because the site did not have a single feedback process, the licensee could not provide the inspectors with the total number of open feedback items. The inspectors noted that in NRC Annual Assessment Letter 05000528/2006001; 05000529/2006001; 05000530/2006001, the NRC concluded that during the 2005 assessment period, the licensee's actions had not completely corrected the root causes associated with procedural adequacy. In a response letter dated April 4, 2006, the licensee stated an action tracking system would be implemented as the single management tool to identify and track the status of procedure change requests, and that this action would be completed by the second quarter of 2006. The inspectors determined that this action was not complete or effective during the time of the inspection. Following the onsite inspection, the licensee identified that approximately 1845 open procedure change requests existed. The licensee stated their goal was to reduce this backlog and maintain the average life of procedure change requests to 60 days.

The inspectors noted NAD Audit 2004-011 identified a number of procedural adequacy problems. The audit stated, in part, that six incorrect/outdated surveillance tests were identified that had not been revised since 1998. The audit team identified approximately 50 procedures that had not been reviewed or revised since 1998, that may also contain similar errors and non-compliances with administrative requirements. The audit concluded that the extent of condition could not be determined unless a complete review of approximately 1300 site procedures was performed. Significant CRDR 2732484, dated August 18, 2004, documented this concern and contained the action items to complete the review of all affected procedures. During the inspection the inspectors noted that these actions had not been completed. The licensee stated they were currently considering closing this action to another action that would involve standardizing all site procedures. The inspectors concluded, that although the licensee's plans to standardize all site procedures could potentially address the inadequate procedure concerns, the timeliness of these corrective actions was not appropriate based on the history of procedural problems at the facility.

Analysis: The performance deficiency was associated with the failure to implement timely corrective actions to identify and correct deficient procedures and instructions. This finding is greater than minor because the failure to identify and correct these deficiencies, if left uncorrected, would become a more significant safety concern in that quality related SSC's could be adversely affected by implementing inadequate instructions. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding was determined to have very low safety significance because it did not result in a loss of operability per, "Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment." This finding involved problem identification and resolution crosscutting aspects associated with the failure to promptly identify and correct deficient procedures/instructions resulting in the potential to adversely affect quality related SSCs.

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to this, the licensee failed to promptly identify and correct a condition adverse to quality. Specifically, since 1992, the licensee failed to maintain procedures and written instructions in accordance with quality assurance program requirements, including, periodic procedural reviews and implementation of the procedure feedback process. These deficiencies resulted in a significant number of identified deficient procedures and instructions not being corrected in a timely manner and not receiving adequate reviews. One example involved the failure to provide adequate instructions for mounting temperature element housings adversely affecting seismic qualifications required to protect the functionality of safety related equipment. Because this violation is of very low safety significance and has been entered into the CAP as

CRDR 2952142, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2006005-06, “Failure to Maintain Procedures and Instructions."

.4 Crosscutting Issues Follow-up Inspections

The inspectors conducted periodic discussions with licensee management to monitor their progress in addressing the substantive crosscutting concerns and Performance Improvement Plan implementation. On December 8, 2006, the licensee provided the NRC with the closure plans which discuss corrective actions and effectiveness measures that will be implemented to improve their performance in the crosscutting areas of human performance and problem identification and resolution. The licensee also indicated that they would inform the NRC when they were ready to support an assessment of their corrective actions associated with these areas.

.5 Cross-References to Problem Identification and Resolution Findings Documented Elsewhere

Section 1R15.1 describes a finding where the licensee failed to take appropriate corrective actions to address safety issues in a timely manner.

Section 4OA2.2 describes a finding where the licensee failed to thoroughly evaluate a problem associated with a BW safety-related check valve that was known to exist since November 2000.

Section 4OA2.3 describes a finding where the licensee failed to promptly identify and correct deficient procedures/instructions resulting in the potential to adversely affect quality related SSCs.

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

a. Inspection Scope

Event Follow Up

The inspectors reviewed the two below listed events and degraded conditions for plant status and mitigating actions to: (1) provide input in determining the appropriate agency response in accordance with Management Directive 8.3, "NRC Incident Investigation Program;" (2) evaluate performance of mitigating systems and licensee actions; and (3) confirm that the licensee properly classified the event in accordance with emergency action level procedures and made timely notifications to NRC and state/governments, as required.

- On September 22, 2006, the Unit 3 EDG Train A failed to develop an output voltage during a post-maintenance surveillance test. This failure was similar to a failure that occurred on July 25, 2006. Both failures involved the EDG failing to obtain an output voltage during surveillance testing because of a faulty K-1 relay operation. In accordance with Management Directive 8.3, a special inspection was initiated on October 2, 2006. The results of the inspection are documented in NRC Special Inspection Report 05000528; 05000529; 05000530/2006012.

- On October 6, 2006, Unit 1 SI system check Valve SI-134 failed an inservice leak test. The licensee identified deficiencies with the internal disc bearing which was believed to have caused the valve to stick in a partially open position. An in-depth review was performed November 13-17, 2006, to fully investigate the issue. See Section 4OA2 for the results of the inspection.

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed two samples.

Event Report Reviews

The inspectors reviewed the nine below listed Licensee Event Reports (LERs) and related documents to assess: (1) the accuracy of the LER; (2) the appropriateness of corrective actions; (3) violations of requirements; and (4) generic issues.

.1 <u>(Closed) LER 05000528/2005005-00</u>, "Unplanned Reactor Trip and Engineered Safety Feature Actuation"

This issue was dispositioned as NCV 05000528/2005004-02, "Improper Control of Steam Generator Feedwater System Resulted in a Reactor Trip and Main Steam Isolation." The inspectors reviewed the LER and identified no additional concerns. This LER is closed.

.2 <u>(Closed) LER 05000528/2005001-02</u>, "Actuation of an Unit 1 Emergency Diesel Generator and Plant Shutdown Required by TS"

This LER is a supplement to LERs 05000528/2005001-00 and 05000528/2005001-01, which were closed in NRC Inspection Report 05000528; 05000529; 05000530/2006004. This supplement provided the most probable root cause of the bus failure and the licensee's corrective actions. The inspectors reviewed this LER and no additional findings were identified. This LER is closed.

.3 <u>(Closed) LER 05000528/2003001-01</u>, "Pressurizer Safety Valve As-Found Lift Pressure Outside of Technical Specification Limits"

This LER is a supplement to LER 05000528/2003001-00, which was closed in NRC Inspection Report 05000528; 05000529; 05000530/2005005. This supplement provided the root cause of the pressurizer safety valve being outside TSs. The inspectors reviewed this LER and no additional findings were identified. This LER is closed.

.4 <u>(Closed) LER 05000529/2003003-01</u>, "Source Range Inoperable During Core Reload"

This LER is a supplement to LER 05000529/2003003-00, which was closed in NRC Inspection Report 05000528; 05000529; 05000530/2004005, and dispositioned as NCV 05000529/2004005-07. This supplement provided the root cause of the event. The inspectors reviewed the LER and identified no additional concerns. This LER is closed.

.5 (Closed) LER 05000529/2005004-01, "Technical Specification Required Shutdown Due to Core Protection Calculators Inoperable"

This LER is a supplement to LER 05000529/2005004-00, which was closed in NRC Inspection Report 05000528; 05000529; 05000530/2006008. This supplement provided the root cause of the event. The inspectors reviewed this LER and no additional findings were identified. This LER is closed.

.6 (Closed) LERs 05000530/2006004-00 and 05000530/2006004-01, "Emergency Diesel Generator Actuation on Loss of Power to A Train 4.16KV Bus"

This issue was dispositioned as NCV 05000530/2006003-06, "Failure to Follow GTG Surveillance Procedure Causes Loss of Power to Safety-Related Bus." The inspectors reviewed these LERs and identified no additional concerns. This LER is closed.

.7 (Closed) LER 05000530/2006002-00, "Automatic Reactor Protection System Actuation Due to an Invalid Control Element Assembly Calculator Penalty Factor"

On March 5, 2006, the control room staff received an alarm from control element assembly calculator (CEAC) Number 1, indicating a deviation from control element assembly (CEA) Number 60. The operators determined that CEA Number 60 was in the correct position and that the alarm was an indication problem. The operators entered Procedure 72AO-9SB01, "CEAC Inoperable," Revision 10, and proceeded to remove CEAC Number 1 from service by entering the appropriate computer codes in the core protection calculators (CPCs). While the operators were in the process of entering the codes, the CEA indicated deviation increased until CEAC Number 1 generated a penalty factor that exceeded the setpoint for departure from nucleate boiling ratio, causing a reactor trip. After the trip the licensee determined that the indication problem was generated by a faulty CEA positional isolation amplifier, which was replaced prior to plant restart. The inspectors reviewed this LER and no findings of significance were identified and no violation of NRC requirements occurred. This LER is closed.

.8 (Closed) LER 05000529/2006001-00, "TS Required Reactor Shutdown on Failure to Complete Repairs on an AFW Valve Within the 7 Day Completion Time"

On April 3, 2006, during the performance of the AFW turbine driven pump inservice surveillance test, operations personnel obtained inconsistent position indication for steam admission Valve SG-138A. The valve was declared inoperable and maintenance personnel initiated repairs. The maintenance activities included replacement of the coil and fuse, reed switch, and valve internals. Since these activities were not successful in restoring the valve to an operable condition within the 7 day completion time allowed by TSs, the licensee initiated a TS required reactor shutdown on April 10, 2006. After the shutdown, the entire valve was replaced and restored to service. The inspectors reviewed this LER and no findings of significance were identified and no violation of NRC requirements occurred. This LER is closed.

.9 (Closed) LER 05000529/2006003-00, "Unit 2 Variable Overpower Reactor Trip During Main Turbine Control Valve Restoration"

The inspectors reviewed this LER and CRDR 2913232 to assess the cause, analysis, and corrective actions for this event. See the Findings portion of this section for results of the review. This LER is closed.

Documents reviewed by the inspectors are listed in the attachment.

Personnel Performance

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 non-routine events and transients; (2) verified that operator actions were 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 non-routine evolutions sampled.

- On October 11, 2006, Unit 2 was performing a full core offload to support refueling Outage 1R13 activities. While lowering fuel Assembly P2P216 in the spent fuel pool Location FF14, the operators reported that they received an underload, overload, and maximum overload indications. It was also reported that the SFHM slightly shook. Evaluation of these indications concluded that the fuel assembly had contacted the top of the fuel rack at a higher than designed speed. Fuel movement was immediately stopped, and conditions were reported to the shift manager and fuels supervision. A "Fuel Handling Event Recovery Checklist," per Procedure 40DP-9OP02, "Conduct of Shift Operations," Revision 36, was initiated and Abnormal Operating Procedure 40AO-9ZZ22, "Fuel Damage," Revision 9, was entered since the entry condition of an, "Unintentional contact of an irradiated fuel assembly with any solid structure," was met. Fuel Assembly P2P216 was inspected following this event and no damage was observed. This event was documented in CRDR 2931991. See Section 1R17 for findings of significance associated with this event.

- On October 19, 2006, Unit 3 was manually tripped when lowering condenser hotwell level caused two condensate pumps to trip coincident with degrading condenser vacuum. The loss of two condensate pumps while operating at essentially full power caused a reduction in main feedwater pump suction pressure and the actuation of low suction pressure pre-trip alarms for both main feedwater pumps. Operations personnel initiated a manual reactor trip based on recognition of the degrading condition in the secondary plant. The lowering hotwell level and degrading condenser vacuum was a result of a valve that failed open associated with the condensate demineralizers which created an opening from condenser Shell C to atmosphere. The unit was stabilized in Mode 3 following the manual trip and performance of standard post trip actions. This event was documented in CRDR 2934020.

- On October 26, 2006, a loss of power occurred to Unit 1 Class 1E 4.16 kV Bus 1EPBBS04 and Unit 3 Class 1E 4.16 kV Bus 3EPBBS04. The loss of power to the safety-related buses was a result of the tripping of Unit 1 13.8 kV alternate supply Breaker 1ENANS06F and Unit 3 13.8 kV normal supply Breaker 3ENANS06C. The event occurred during preparations to restore power to 13.8 kV Bus 2ENANS05/2ENANS03 during refueling Outage 2R13. The 13.8 kV breakers unexpectedly tripped when closing the door to Cubicle 1ENANS06G following installation of the potential transformer fuses during the restoration. The licensee's investigation of the event determined that the breakers tripped when an auxiliary relay mounted on the cubicle door inadvertently actuated due to excessive vibration while closing the door. Unit 1 EDG Train B and Unit 3 EDG Train B started and loaded as designed to restore power to the Class 1E buses. This event was documented in CRDR 2936341.

- On November 4, 2006, an inadvertent water inventory transfer occurred from the Unit 2 refueling water tank (RWT) to the RCS. The transfer occurred during realignment to SDC operations following surveillance testing of HPSI Train B. The water transfer occurred due to an improper valve configuration and approximately 500 gallons of RWT water was transferred to the RCS through the SDC suction isolation valves. The crew noted the transfer and closed containment spray (CS) pump discharge isolation Valve SIB-HV-679 to stop the event. This event was documented in CRDR 2939290.

- On November 4, 2006, another inadvertent water inventory transfer occurred from the Unit 2 RWT to the RCS after swapping SDC operations from Train A to Train B. The water transfer occurred due to another improper valve configuration and approximately 500 gallons of RWT water was again transferred to the RCS. The crew noted the transfer and closed CS pump discharge isolation Valve SIA-HV-684 to stop the event. This event was documented in CRDR 2939290.

- On November 5, 2006, Unit 2, operations personnel began a test of an AFW pump per Procedure 73ST-9AF01, "APN-P01 - Inservice Test," Revision 10. Shortly after the pump was started, an auxiliary operator noted the pump casing was abnormally warm. The operator notified the control room and the pump was secured after running approximately 6 minutes. Subsequently, the licensee identified that the discharge flow paths were inappropriately isolated. This event was documented in CRDR 2939600.

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed six samples.

b. Findings

.1 Reactor Trip Following Control Valve Testing

Introduction. A Green self-revealing NCV of TS 5.4.1.a was identified for the failure of maintenance personnel to use an adequate procedure for the repairs and restoration of control Valve 2, resulting in a reactor trip during main turbine control valve restoration.

Description. On July 24, 2006, while Unit 2 was operating at full power, the control room received an alarm indicating high turbine first stage pressure. The transient caused reactor power to increase to 100.25 percent, while cold leg temperature decreased from 558.1 F to 557.6 F. The operators reduced turbine load by adjusting the load limit potentiometer and reactor power decreased to 99.9 percent. An auxiliary operator was dispatched to the main turbine control valves and noticed that control Valve 2 was fully open. A subsequent walk down of the control valve by maintenance personnel revealed that the linear variable differential transformer rod, had disconnected from the spring assembly rod-end bearing. Further inspections concluded that vibration at the linear variable differential transformer rod caused the jam nut to become loose. This condition in the linkage allowed the loosening of the rod, which caused the threads to wear and the cotter pin to fail. The failure of the linkage caused control Valve 2 to fully open, resulting in the transient.

On July 26, maintenance personnel developed a plan of action to repair the differential transformer linkage. The plan of action directed operations personnel to reduce power to 93 percent, close control Valve 2, and maintain it in that position until repair of the linkage was completed. Operations personnel used Procedure 40OP-9MT02, "Main Turbine," Revision 53, to close control Valve 2, and WO 2912696 to install a jumper in the test button circuitry to maintain the valve closed. Reactor power was further reduced to 90 percent as a conservative measure prior to completing the repairs. Several hours later during equipment restoration, operations personnel pressed the test button and maintenance personnel removed the jumper. When operations personnel released the test button and control Valve 2 opened, there was an unexpected sudden increase in first stage pressure from 625 psig to 695 psig. This increase in first stage pressure caused the other control valves to close, reducing steam flow by approximately 44 percent and reactor power from 90 to 88 percent. The rapid decrease in steam flow caused the steam bypass control system to quick open, causing a 5 degree cooldown of the RCS. This cooldown was sufficient to increase reactor power at a faster rate than the variable overpower trip setpoint. Consequently, when reactor power increased to 98 percent as a result of the 5 degree cooldown, the variable overpower trip setpoint was exceeded and the reactor tripped.

The licensee's investigation determined the direct cause of the trip was a momentary introduction of wet steam to the turbine first stage. The wet steam rapidly heated and expanded causing an anomalous indication of first stage pressure not commensurate with actual turbine load. The root cause of the event was determined to be inappropriate use of Procedure 40OP-9MT02 for the maintenance activity. Procedure 40OP-9MT02 is used monthly for control valve testing. During the monthly test the operators press the test button to close a control valve and immediately release it when the valve is closed. The intent of this procedure was for momentary closure of a control valve during monthly testing. The procedure was not intended for use to perform maintenance over extended periods where moisture could accumulate in the steam piping.

Analysis. The performance deficiency associated with this finding involved the failure of maintenance personnel to use an adequate procedure for the maintenance of control Valve 2, which caused a reactor trip. The finding is greater than minor because it would become a more significant safety concern if left uncorrected in that more significant consequences would occur if inadequate procedures are used for plant maintenance. The finding affected the initiating events cornerstone. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the condition only affected the initiating events cornerstone and did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. This finding has a crosscutting aspect in the area of human performance associated with work control because the licensee did not appropriately coordinate work activities by incorporating actions to address the impact of changes to the work scope of the maintenance procedure.

Enforcement. TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Item 9.a requires procedures that are appropriate to the circumstances for performing maintenance. Procedure 40OP-9MT02, "Main Turbine," Revision 53, is used for monthly control valve testing. Contrary to the above, on July 26, 2006, maintenance personnel used Procedure 40OP-9MT02 in a way that was not appropriate for the circumstances. Specifically, on July 26, 2006, maintenance personnel used Procedure 40OP-9MT02 for performing repairs and restoring control Valve 2 in a way that was beyond the scope of the procedure. The use of the inadequate procedure resulted in a plant transient and reactor trip. Because this violation is of very low safety significance and has been entered into the CAP as CRDR 2913232, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000529/2006004-07, "Inadequate Procedure Used for Maintenance Results in Reactor Trip."

.2 Two Examples of Plant Configuration Control Errors

Introduction. Two examples of a self-revealing Green NCV of TS 5.4.1.a were identified for the failure of operations personnel to properly implement procedures to ensure the correct configuration of equipment during plant evolutions.

Description. On November 4, 2006, two RCS inventory control events occurred.

The first inadvertent water inventory transfer from the RWT to the RCS occurred during realignment to SDC Train B operations following HPSI Train B full flow testing per Procedure 73ST-9XI33, "HPSI Pump and Check Valve Full Flow Test," Revision 40. The test realigned the CS Train B subsystem to pump RCS inventory back to the RWT. Procedure 73ST-9XI33, Step 9.0, "System Restoration," directed operations personnel to restore the system to the desired alignment following the test. The desired alignment for the plant conditions should have been to place the system in standby for SDC operations to satisfy the entry conditions for Procedure 40OP-9SI01, "Shutdown Cooling Initiation," Revision 38. Operations personnel incorrectly assumed that Procedure 73ST-9XI33 contained the steps to restore the system to the desired alignment and that no further action was necessary to comply with Step 9.0. Consequently, the system was not in the required standby lineup in that CS pump discharge isolation Valve SIB-HV-689 remained open. During the subsequent SDC alignment per Procedure 40OP-9SI01, a gravity flow-path was inadvertently created through the CS system and about 500 gallons of RWT water was transferred to the RCS through the SDC suction isolation valves. The crew noted the transfer and closed redundant CS pump discharge isolation Valve SIB-HV-679 to stop the event.

The inventory transfer event was reviewed by crew supervision to determine how the water had been transferred. The crew recognized that a gravity flow path had been established through the CS pump to the RCS since Valve SIB-HV-689 was out of position. The crew believed that this was an isolated configuration control error because the off-going crew incorrectly informed them that CS pumps were properly aligned to the SDC system. Believing that they had corrected the configuration control issue, and relying on the equipment status turnover from the off-going crew, operations personnel continued with the SDC train swap evolution without any further investigation.

A second inadvertent transfer occurred following the SDC train swap from Train A to Train B. After stopping LPSI pump Train A following the train swap, RWT water flowed into the RCS through the CS pump discharge check valve when the RWT pressure head overcame lowering LPSI pump discharge pressure, which unexpectedly allowed the check valve to unseat. After approximately 500 gallons had transferred, the crew noted the level change and stopped the inventory transfer by closing CS pump Train A discharge isolation Valve SIA-HV-684, which isolated the flow path. The CS pump discharge check valve unseated since Valve SIA-HV-684 was inappropriately left open during an earlier test per Procedure 40ST-9SI09, "ECCS System leak Test," Revision 31. Procedure 40ST-9SI09, Step 8.9.23, directed operations personnel to align the CS system as directed by the control room supervisor/shift manager for plant conditions. Similar to the error made earlier in the day when restoring from Procedure 73ST-9XI33, operations personnel that performed Procedure 40ST-9SI09 incorrectly assumed that the surveillance test contained the steps to restore the system to the desired alignment and that no further action was necessary to comply with Step 8.9.23. Failure to properly restore the system to the SDC standby lineup, including the failure to close Valve SIA-HV-684, established the latent system configuration condition that allowed the second event to occur when LPSI pump Train A was secured.

The licensee performed a significant root cause investigation for these events and documented the results in CRDR 2939686. The investigation determined that the root causes of the events were; (1) system status control during outages lacks fundamental ownership by Operations and Outage Management, and (2) the current status control process employed during outages lacks the formality and rigor necessary to ensure that requisite system status control is maintained. Furthermore, the investigation determined that a contributing cause included that command and control conventions described in Procedure 40DP-9OP02, "Conduct of Shift Operations," were not being consistently adhered to during outages, and led to an environment where human performance errors were more likely.

During this period of recovery from the refueling outage, multiple surveillance tests were being performed which created a period of high activity, to the extent that equipment status control became difficult to maintain. Appropriately, the licensee's investigation also observed that schedule pressure, or the perception of schedule pressure, from the outage control center was pervasive throughout much of the Operations organization and contributed to this event. The issue of human performance errors by operations personnel due to self-imposed schedule pressures during periods of high activity was identified previously by the NRC and documented as NCV 05000528; 05000529; 05000530/2006003-07.

Analysis. The performance deficiency associated with this finding involved the failure of operations personnel to adequately implement procedures to maintain configuration control of the plant. The finding is greater than minor because it is associated with the configuration control cornerstone attribute of the mitigating systems cornerstone and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process," Checklist 3, the finding is determined to have very low safety significance because the finding did not result in an increase in the likelihood of a loss of decay heat removal due to failure of the system, nor did it degrade the ability of containment to remain intact following an accident. Additionally, the finding did not degrade the licensee's ability to terminate a leak path, add RCS inventory, recover decay heat removal once it is lost, or establish an alternate core cooling path. Lastly, the finding did not increase the likelihood of a loss of RCS inventory, or offsite power. This finding has a crosscutting aspect in the area of human performance associated with work control because the licensee did not appropriately coordinate work activities by communicating, coordinating, and cooperating with each other during the surveillance testing activities.

Enforcement. TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Item 8(1)(j), requires procedures for surveillance tests on the ECCS. Procedure 73ST-9XI33, "HPSI Pump and Check Valve Full Flow Test," Revision 40, Step 9.0, "System Restoration," directed operations personnel to restore the system to the desired alignment following the test. The desired alignment for the plant conditions should have been to place the system in standby for SDC operations. Procedure 40ST-9SI09, "ECCS System leak Test," Revision 31, Step 8.9.23, directed operations personnel to align the CS system as directed by the control room supervisor/shift manager for plant conditions. The desired alignment for the plant conditions should have been to place the system in standby for SDC operations. Contrary to the above, twice on November 4, 2006, operations personnel failed to restore the CS system to standby operations for SDC following surveillance testing to satisfy the entry conditions for Procedure 40OP-9SI01, "Shutdown Cooling Initiation," Revision 38. Because this violation is of very low safety significance and has been entered into the licensee's CAP as CRDR 2939686, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000529/2006005-08, "Failure to Follow Procedures Results in Loss of Plant Configuration Control."

4OA5 Other Activities

.1 (Closed) Temporary Instruction 2515/160: Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors

The first occurrence of TI 2515/160 was documented for Unit 3 in NRC Inspection Report 05000528; 05000529; 05000530/2004-005. The second occurrence of TI 2515/160 for Unit 2 was documented in NRC Inspection Report 05000528; 05000529; 05000530/2005-003. The third occurrence of TI 2515/160 for Unit 1 was performed during the inspection period covered by NRC Inspection Report 05000528; 05000529; 05000530/2005-003. Therefore, TI 2515/160 is now closed for Units 1, 2, and 3.

.2 (Closed) Unresolved Item (URI) 05000528; 05000529; 05000530/2004012-16: Grid Reliability, Independence, and Stability

a. Inspection Scope

On June 14, 2004, a loss of all offsite power and three-unit plant trip event identified a vulnerability on Palo Verde’s offsite power system in that a failure of one breaker could lead to a loss of both offsite power sources for each of the nuclear units. The staff raised concerns whether the Palo Verde offsite power design met the requirements of General Design Criteria (GDC) 17. NRC personnel reviewed the corrective actions of the licensee, to ensure this vulnerability was properly addressed.

In response to the loss of all offsite power event on June 14, 2004, the licensee has corrected certain root causes to address the vulnerability of the offsite power, and conducted a study led by Western Electricity Coordinating Council (WECC). The corrective actions are as follows:

- The WECC Disturbance Report Task Force studied the loss of all offsite power event of June 14, 2004, and identified weaknesses in the transmission protection schemes remote from Palo Verde. Specifically, it identified that the transmission protection schemes used in the remote substation did not have adequate redundancy to ensure that electrical faults would be cleared in a timely manner in the event of a single failure of a protective device or relay. In a fax transmittal to regional and Nuclear Reactor Regulation (NRR) personnel on August 24, 2006, Palo Verde engineers described how these issues were corrected to prevent the propagation of external electrical faults/problems in the transmission system, thereby assuring that a similar loss of all offsite power event will not cause Palo Verde to lose both offsite power sources for each of the nuclear units.

- The arrangement of the 525 kV switchyard at Palo Verde utilizes a "breaker-and-a-half" scheme in which three breakers are used to protect every two terminations, either line or transformers. The 525 kV switchyard is protected by two independent protective relaying schemes that are designed to protect against any faults within the switchyard. The protective schemes are designed to isolate a fault at any location in the switchyard and would not affect the supply of offsite lines. The licensee demonstrated that the loss of any two adjacent sections of the switchyard, due to a fault on one section and clearing of an adjacent section, would not result in loss of more than one startup transformer supply circuit. Therefore, this assures that offsite power will be available to the safety buses.

- The licensee has evaluated the impact of any single breaker failing to clear an electrical fault at the 525 kV switchyard. As discussed in the above item, a failure of a single breaker would not remove more than one offsite power supply unless a critical portion of the switchyard was already taken out of service prior to the fault. The licensee stated that, when a portion of the switchyard is taken out of service, additional precautions are put in place to minimize the probability of faults.

In summary, Region IV and NRR staff have reviewed the information provided by the licensee in response to the questions raised by NRC staff to address potential vulnerabilities of the offsite power resulting from the event of June 14, 2004. The licensee identified the weaknesses in the transmission protection schemes, which were remote from Palo Verde, that caused the June 14, 2004, event. The staff agrees that the propagation of external electrical faults/problems in the transmission system would not cause a loss of all offsite lines at the 525 kV switchyard based on the licensee's correction of the identified problems. Because the identified corrective actions were to equipment normally outside of the licensee's control, the NRC also concluded there was no violation of NRC requirements. Additionally, the staff concluded that a single breaker failure in the 525 kV switchyard would not result in a loss of more than one offsite power supply. The staff concludes that the Palo Verde's offsite power system design meets GDC 17 requirements. This URI is closed.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

On October 20, 2006, the engineering inspectors presented the results of the inservice inspection review to Mr. J. Levine, Executive Vice President, Generation, and other members of licensee management. Licensee management acknowledged the inspection findings.

On January 4, 2007, the resident inspectors presented the inspection results to Mr. J. Levine, Executive Vice President, Generation, and other members of the licensee management staff at the conclusion of the quarterly inspections. 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 safety 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 a NCV.

- 10 CFR Part 50, Appendix B, Criterion V requires that activities affecting quality be prescribed by documented instructions of a type appropriate to the circumstances. The licensee identified that instructions for mounting temperature element housings contained inappropriate torque values to ensure seismic qualifications. This event is documented in the licensee's corrective action program as CRDR 2908848. This finding is of very low safety significance because it did not result in a loss of operability per, "Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment."

- Regulatory Guide 1.33, Appendix A, Item 1c, requires procedures for equipment control. Procedure 40DP-9OP09, "System Status Control," Revision 41, Section 3.4, states that, "Alignment restoration is controlled by the governing TD section," and that, "Once restored by the TD, the system is placed in service as required by the appropriate normal operating procedure." Contrary to the above, on November 5, 2006, the AFW system was placed in service for operation when restoration of the system was not complete since only portions of TD 40TD-9AF01, "Auxiliary Feedwater System," Revision 16, had been performed to realign the system. This finding is determined to have very low safety significance because the finding did not increase the likelihood of a loss of RCS inventory. Additionally, the finding did not degrade the licensee's ability to terminate a leak path or add RCS inventory, neither did it degrade the licensee's ability to recover decay heat removal once it is lost.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
G. Andrews, Department Leader, System Engineering
S. Bauer, Department Leader, Regulatory Affairs
D. Berg, Senior Engineer, Design Mechanical
L. Berg, Senior Engineer, Mechanical Engineering
P. Borchert, Director, Operations
R. Buzard, Senior Consultant, Regulatory Affairs
D. Carnes, Director, Nuclear Assurance
P. Carpenter, Unit Department Leader, Operations
C. Churchman, Director, Engineering
S. Coppock, Department Leader, Technical Services
D. Coxon, Unit Department Leader, Operations
C. Eubanks, Vice President, Nuclear Operations
J. Gaffney, Director, Radiation Protection
D. Hanson, Steam Generator System Engineer
D. Hautala, Senior Compliance Engineer
R. Henry, Site Representative, Salt River Project
J. Hesser, Director, Emergency Services
M. Hooshmand, Section Leader, Systems Engineering
M. Karbasian, Department Leader, Design Mechanical Engineering
B. Kershaw, Senior Engineer, Engineering Services
B. Lindenlaub, Senior Engineer, Engineering Services
D. Mauldin, Vice President, Engineering
M. McGhee, Unit Department Leader, Operations
S. McKinney, Department Leader, Operations Support
J. Mellody, Department Leader, Communications
M. Melton, Section Leader, Inservice Inspection
E. O'Neil, Department leader, Emergency Preparedness
M. Perito, Plant Manager, Nuclear Operations
J. Proctor, Section Leader, Regulatory Affairs - Compliance
S. Quan, Senior Engineer, Engineering Services
M. Radspinner, Section Leader, Systems Engineering
T. Radtke, General Manager, Emergency Services and Support
F. Riedel, Director, Nuclear Training Department
J. Scott, Section Leader, Nuclear Assurance
C. Seaman, General Manager, Regulatory Affairs and Performance Improvement
M. Shea, Director, Maintenance
E. Shouse, Representative, El Paso Electric
D. Straka, Senior Consultant, Regulatory Affairs
K. Sweeney, Steam Generator Section Leader
J. Taylor, Nuclear Project Manager, Public Service of New Mexico
D. Vogt, Section Leader, Operations Shift Technical Advisor
T. Weber, Section Leader, Regulatory Affairs
C. Zell, Director, Work Management

Others
E. Merschoff, Consultant
L. Davis, NDE Level III Examiner, Lambert MacGill Thomas, Inc.
L. Hobson, Welding Superintendent, PCI Energy Services
R. Hogstrom, Authorized Nuclear Inservice Inspector, Hartford Steam Boiler Insurance and Inspection Company

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000528;05000529; 05000530/2005002-01	NCV	Scaffolding Erected with Inadequate Clearances and No Engineering Evaluation (Section 1R15.1)
05000528/2006005-02	NCV	Two Examples of Failure to Properly Implement Operability Determination Process (Section 1R15.2)
05000528;05000529; 05000530/2006005-03	NCV	Failure to Maintain Seismic Qualification of Post Accident Monitoring Instrumentation (Section 1R15.3)
05000529/2006005-04	NCV	Inadequate Acceptance Testing for the Upgraded Refueling Equipment (Section 1R17)
05000529/2006005-05	NCV	Failure to Perform an Adequate Root Cause Analysis for Valve SI-225 (Section 4OA2)
05000528;05000529; 05000530/2006005-06	NCV	Failure to Maintain Procedures and Instructions (Section 4OA2)
05000529/2006005-07	NCV	Inadequate Procedure Used for Maintenance Results in Reactor Trip (Section 4OA3)
05000529/2006005-08	NCV	Failure to Follow Procedures Results in Loss of Plant Configuration Control (Section 4OA3)

Closed

05000528/2005005-00	LER	Unplanned Reactor Trip and Engineered Safety Feature Actuation
05000528/2005001-02	LER	Actuation of an Unit 1 Emergency Diesel Generator and Plant Shutdown Required by TS
05000528/2003001-01	LER	Pressurizer Safety Valve As-Found Lift Pressure Outside of Technical Specification Limits
05000529/2003003-01	LER	Source Range Inoperable During Core Reload
05000529/2005004-01	LER	Technical Specification Required Shutdown Due to Core Protection Calculators Inoperable

05000530/2006004-00 and 2006004-01	LER	Emergency Diesel Generator Actuation on Loss of Power to A Train 4.16KV Bus
05000530/2006002-00	LER	Automatic Reactor Protection System Actuation Due to an Invalid Control Element Assembly Calculator Penalty Factor
05000529/2006001-00	LER	TS Required Reactor Shutdown on Failure to Complete Repairs on an AFW Valve Within the 7 Day Completion Time
05000529/2006003-00	LER	Unit 2 Variable Overpower Reactor Trip During Main Turbine Control Valve Restoration
05000528;05000529; 05000530/2004012-16	URI	Grid Reliability, Independence, and Stability

Discussed

None

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 Protection

Procedures

Number	Title	Revision
40OP-9ZZ17	Cold Weather Protection	29

CRDRs

2920725	85688	2654637	111599	2661843	2782244

Work Orders

2345721	2851375	2947744

Miscellaneous
Updated Final Safety Analysis Report, Sections 2.3 and 9.4

Section 1R04: Equipment Alignment

Procedures

Number	Title	Revision
40OP-9SI01	Shutdown Cooling Initiation	38

Drawings

Number	Title	Revision
02-M-SIP-001	P&I Diagram, Safety Injection and Shutdown Cooling System	33
02-M-SIP-002	P&I Diagram, Safety Injection and Shutdown Cooling System	24
02-M-EWP-001	P&I Diagram, Essential Cooling Water System	26
02-M-PCP-001	P&I Diagram, Fuel Pool Cooling & Cleanup System	24
02-M-PWP-001	P&I Diagram, Plant Cooling Water System	3
02-M-NCP-001	P&I Diagram, Nuclear Cooling Water System	7
01-M-HDP-001	P&I Diagram, HVAC Diesel Generator Building	8
01-M-DFP-001	P&I Diagram, Diesel Fuel Oil & Transfer System	11
02-M-NCP-002	P&I Diagram, Nuclear Cooling Water System	9
01-M-DGP-001	P&I Diagram, Diesel Generator System, Sheets 1 - 9	48
01-P-ZQC-701	Diesel Generator Building Level 1 & 2 HVAC Plan Between El. 100'-0" & 131'-0, Sheet 1 of 2	0
02-M-HDP-001	P&I Diagram, HVAC Diesel Generator Building	8
02-M-DFP-001	P&I Diagram, Diesel Fuel Oil & Transfer System	10
02-M-DGP-001	P&I Diagram, Diesel Generator System, Sheets 1 - 9	46
02-P-ZQC-701	Diesel Generator Building Level 3 HVAC Plan between El. 131'-0" & Roof	1
03-M-DGP-001	P&I Diagram, Diesel Generator System, Sheets 1 - 9	43
13-P-ZGL-701	Diesel Generator Building Equipment Location - Plans	11
13-P-ZGL-702	Diesel Generator Building Equipment Location - Sections	5
13-P-00B-011	General Arrangement Plant at El. 160'-0" - Sections	6

PVARs

2951663	2952195

CRDRs

2928626

Miscellaneous
Control Room Logs
VTD-R281-001, Riley-Bearid, Inc., Specifications for Maxim Model M41 Silencers

Section 1R05: Fire Protection

Procedures

Number	Title	Revision
14DP-0FP33	Control of Transient Combustibles	14
14DP-0FP31	Fire System Impairment	11
14DP-0FP02	Fire System Impairments and Notifications	13
30DP-0WM12	Housekeeping	13
30DP-9MC01	Staging and Control of Maintenance Materials	13
32FT-9QD20	Appendix "R" Emergency Lighting Fixture Battery Discharge Test. Wall Mounted types "KE", "KF", and "KG".	8

Miscellaneous
PVNGS Pre-Fire Strategies Manual, Revision 17
Updated Final Safety Analysis Report, Sections 9.5.1 and 9.5.3
Updated Final Safety Analysis Report, Appendix 9B, Fire Protection Evaluation Report

Section 1R06: Flood Protection Measures

Procedures

Number	Title	Revision
40AL-9RK7C	Panel B07C Alarm Responses	2

CRDRs

2810729	2916296	2934277

Miscellaneous
Design Basis Manual, Auxiliary Feedwater System
13-MC-ZA-807, "Flooding in the auxiliary feedwater pump room"
PVNGS Pre-Fire Strategies Manual, Revision 17

Section 1R08: Inservice Inspection Activities

Procedures

Number	Title	Revision
73TI-9ZZ17	Repair and Replacement - ASME Sec XI	12
90DP-0IP10	Condition Reporting	30
73TI-0ZZ13	Radiographic Examination	12
73TI-0ZZ23	Digital Radiographic Examination	0
73TI-9ZZ05	Dry Magnetic Particle	11
70TI-9ZC01	Boric Acid Corrosion Prevention Program	5
WPS 8MN-GTAW/SMAW	Tungsten Inert Gas Welding - Austenitic Stainless Steel	13
WPS-73WP-0ZZ07	Austenitic Stainless Steel Welding	11
WPS 3-43/52 TB MC-GTAW-N638	Tungsten Inert Gas Welding	15
WDI-ET-002	IntraSpect ET Analysis Guidelines	8
WDI-ET-003	IntraSpect ET Imaging procedure for Inspection of Reactor Vessel Head Penetrations	10
WDI-ET-004	IntraSpect ET Evaluation Guidelines	10
WDI-UT-010	IntraSpect UT Procedure for Inspection of Reactor Vessel Head Penetrations	13
WDI-UT-011	IntraSpect NDE Procedure for Inspection of Reactor Vessel Head Vent Tubes	10
73TI-9RC01	Steam Generator Eddy Current Examinations	25
73TI-0ZZ79	ASME Section XI Appendix VIII Examination of Ferritic Piping	4

ISI Inspection Reports

RT-06-524	Safety Injection Line Welds 2865107-1 and -4
RT-06-596	Safety Injection Min-flow Line Welds 2932479-1 and -2
UT-06-137	Auxiliary Feedwater Pipe to Elbow Weld 02-059-23
UT-06-138	Auxiliary Feedwater Pipe to Elbow Weld 02-059-24

UT-06-139	Steam Generator Blowdown Pipe to Valve Weld 2-065-041
UT-06-140	Steam Generator Blowdown Pipe to Valve Weld 2-065-042
UT-06-141	Steam Generator Blowdown Pipe to Tee Weld 2-065-043
MT-06-043	Support SG-5-H-1

Work Orders

2843123	2865107	2932479	2926104
2864980	2865575	2832746	2804344

Arizona Public Service (APS) Acquisitions Technique Sheets (ACTS), Analysis Technique Sheets (ANTS), and EPRI ETSS (Examination Technique Specification Sheet)

APS ACTS	APS ANTS	EPRI ETSS
B1-RSG R3, B1-OMNI R0	B1-RSG R3, B2-RSG R2, and B3-RSG R1	96004.1 R10
R2-RSG R6, R2-OMNI R0, R5-RSG R4	R2-RSG R1, R5-RSG R3	96910.1 R10

CRDRs

2823508	2837593	2886287	2909323	2924242	2932507
2823646	2837602	2901046	2922036	2932042	2933181
2831339	2886281	2909061	2923664	2932425	2933699
2837590					

Miscellaneous

Number	Title/Description	Rev/Date
Generic Letter 88-05	Boric Acid Corrosion Control of Carbon Steel Reactor Pressure Boundary Components in PWR Plants	3/17/88
	EPRI Appendix H Examination Technique Specification Sheets (ETSS)	9/30/2006
TR-1003138	PWR Steam Generator Examination Guidelines	6
NEI 97-06	Steam Generator Program Guidelines	2
Drawing 13-SG-005-H-001	Pipe Support Assembly	6
Report	Unit 2 Cycle 12 Condition Monitoring Evaluation	5/6/05
Guideline	Replacement Steam Generators, Analysts Guidelines Training Manual	4

Letters APS to NRC 102-04705 and 102-04873	Relief Request 18: Request to use an ambient temperature automatic or machine GTAW temper bead process for certain repairs to J-Groove welds on the Reactor Vessel Head Penetrations	5/22/2002 12/11/2002
Drawing 10005D69	Vent Pipe Repair for Unit 2 Reactor Vessel Head	0
WDI-PJF-1303201-FSR-001	Reactor Vessel Head Inspection Report	0

Section 1R12: Maintenance Effectiveness

Procedures

Number	Title	Revision
73DP-9XI01	Pump and Valve Inservice Testing Program - Component Tables	18
73DP-0XI03	Check Valve Predictive Maintenance and Monitoring Program	10
73DP-9XI05	Check Valve Condition Monitoring Program	2
31MT-9ZZ17	Borg Warner Check Valve Disassembly and Assembly	20
70DP-0MR01	Maintenance Rule	14
40OP-9CH01	CVCS Normal Operations	48
40ST-9RC02	Calculation of RCS Water Inventory	39
73ST-9XI20	Atmospheric Dump Valves - Inservice Test	20

CRDRs

2939506	2905430	2883369	2822409	2802746	2767029	2724954	2716011
2707733	2688263	2775015	2883129	2936965	2847254	2936341	2716019
2704968	2891679	2905430	2861606	2864804	2560022	2304809	2876554
2801921	2600734	2939506					

CRAIs
2940220

Work Orders

2721742	2913455	2863671	2913459	2934428	2939515	2939518	2939520
2830092	2508436	2830092	2330879	2330881	2304533	2810741	2810754
2810769							

Miscellaneous

PVNGS Maintenance Rule Unavailability Detail Report with Mode Changes

Maintenance Rule Functional Failure Review for CRAI 2940220/CRDR 2939506

Maintenance Rule monitoring of Unavailability and Reliability for the ADVs and the ADV N2 system for previous 12 month period

System Health Reports:

- System PB Class 1E 4.16KV Power, January 1, 2006 - June 30, 2006
- System CB Circuit Breakers, January 1, 2006 - June 30, 2006
- System NA Non-Class 1E 13.8KV Power, January 1, 2006 - June 30, 2006
- System SG Main Steam, January 1, 2006 - June 30, 2006
- System CH Chemical and Volume Control, January 1, 2006 - June 30, 2006
- System SF Reactor Control, January 1, 2006 - June 30, 2006

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures

Number	Title	Revision
70DP-0RA03	Probabilistic Risk Assessment Model Control	3
70DP-0RA05	Assessment and Management of Risk When Performing Maintenance in Modes 1 and 2	3
73ST-9X105	AF and CT Valves – Inservice Test	21
40ST-9DG01	Diesel Generator A Test	27
40ST-9DG02	Diesel Generator B Test	31
41ST-1ZZ02	Inoperable Power Source Action Statement	36

Drawings

Vender Drawing Portec Inc. Drawing D72-12200-710	Schematic Regulator Chassis

PVARs

2948762 2949024

CRDRs

2943038 2944624

Work Orders

2817423 2817424 2817421 2855326 2948764 2942942

Miscellaneous
Schedulers Evaluation for Unit 1 December 11-22, 2006
Schedulers Evaluation for Unit 2 December 11-22, 2006
Work week plan for December 11 - December 16, 2006
Permit 132773

Section 1R15: Operability Evaluations

Procedures

Number	Title	Revision
40DP-9OP26	Operability Determination and Functional Assessment	17
30DP-9WP11	Scaffolding Instructions	16

Drawings

Number	Title	Revision
13-E-ZAC-050	Conduit & Tray Notes, Symbols & Details	50
13-P-ZGL-0701	Diesel Generator Building Equipment Location Plans	11
13-P-ZGL-0702	Diesel Generator Building Equipment Location Plans	5
03-M-DGP-001	P&I Diagram, Diesel Generator System, Sheet 1 of 9	4

CRDRs

2932103	2932248	2932507	2925806	2943411	2929770	2924707	2945348
2778582	2866487	2940338	2940354	2940359	2889504	971544	

Work Orders

2883755	2944944	2945103

Miscellaneous
Unit 3 Shift logs

Engineering Evaluation Request 83-SB-006

EEQ-A160-001

Prompt Operability Determination for Degraded Anaconda "Sealtite" Flexible Conduit and Nonconforming Containment Sumps, Revisions 0 and 1

Section 1R17: Permanent Plant Modifications

Procedures

Number	Title	Revision
72IC-9RX03	Core Reloading	30
78OP-9FX03	Spent Fuel Handling Machine	36 and 37
70585664	SFHM Controls Upgrade Project - Unit 2 SFHM Site Installation Procedure	1
70585663	Refueling Machine Controls Upgrade Project - Unit 2 Installation Procedure	0
70585672	Fuel Transfer System Controls Upgrade Project - Unit 2 Installation Procedure	1
70585609	SFHM Controls Upgrade Project - Unit 2 SFHM Site Acceptance Test Procedure	1
70585619	Refueling Machine Controls Upgrade Project - Unit 2 Site Acceptance Test Procedure	0
70585629	Fuel Transfer System Controls Upgrade Project - Unit 2 Site Acceptance Test Procedure	0

Drawings

Number	Title	Revision
A-07074504-D	Hydraulic Power Unit	3

CRDRs

2936267	2932849	2937300	2931655	2939742	2937542	2937420	2931991

Work Orders

2932074

Section 1R19: Postmaintenance Testing

Procedures

Number	Title	Revision
73ST-9XI26	NCE-V118, CHN-V835, and SI Train A Check Valve - Inservice Test	3
73ST-9SI05	Leak Test of HPSI/LPSI Containment Isolation Check Valves	16
73DP-9XI02	Pump and Valve Inservice testing Program – Administrative Requirements	14

30DP-9WP04	Post-Maintenance Testing Development	13
30DP-9MP09	Preventive Maintenance Processes and Activities	13
40ST-9DG01	Diesel Generator A Test	27
40OP-9DG01	Emergency Diesel Generator A	47
41ST-1ZZ02	Inoperable Power Source Action Statement	36

PVARs

2949783 2949938 2948762

CRDRs

2943038

Work Orders

2864186 2931210 2926211 2817423 2817424 2817421 2855326 2948439

2942942 2948764 2949169 2949073

Miscellaneous
Permit 135517

Section 1R20: Refueling and Other Outage Activities

Procedures

Number	Title	Revision
40OP-9ZZ20	Reduced Inventory Operations	8
40ST-9ZZ09	Containment Cleanliness Inspection	13
40DP-9SI02	Recovery From Shutdown Cooling to Normal Operating Line Up	72
73ST-9SI03	Leak Test of SI/RCS Pressure Isolation Valves	41
73ST-9SI05	Leak Test of HPSI/LPSI Containment Isolation Check Valves	16
73ST-9SI06	Containment Spray Pumps and Check Valves - Inservice Test	21

Drawings

Number	Title	Revision
01-M-NCP-001	P & I Diagram Nuclear Cooling Water System	9

01-M-SIP-001	P & I Diagram Safety Injection & Shutdown Cooling System	34
01-M-SIP-002	P & I Diagram Safety Injection & Shutdown Cooling System	29

Permits

125633	128864	129375	129404	130783	131143	131908	132544
133173							

Miscellaneous
Refueling Outage 2R13 Scope Change Requests
Technical Specification Component Condition Record Report

Section 1R22: Surveillance Testing

Procedures

Number	Title	Revision
74DP-9CY04	Systems Chemistry Specifications	43
74DP-9CY03	Chemistry Control Instruction	4
74OP-9SC02	Sampling Instructions for Auxiliary Systems	23
40DP-9OP06	Operations Department Repetitive Task Program	88

CRDRs

2897810

Work Orders

2792863 2793036

Miscellaneous
System Health Report, Essential Spray Ponds, Jan 1, 2006 - Jun 30, 2006

Section 1R23: Temporary Plant Modifications

PVARs

2947952

Work Orders

2946137

Miscellaneous
10 CFR 50.59 applicability determination for Temporary Modification 2947993, Revision 1

Section 4OA2: Identification and Resolution of Problems

Procedures

Number	Title	Revision
31MT-9ZZ17	BW Check Valve Disassembly and Assembly	22
40DP-9OP06	Operations Department Repetitive Task Program	88
40DP-9OP26	Operability Determination and Functional Assessment	17
70DP-0MR01	Maintenance Rule	14
73DP-0XI03	Check Valve Predictive Maintenance and Monitoring Program	12
73DP-9XI01	Pump and Valve Inservice Testing Program-component Tables	18
73DP-9XI02	Pump and Valve Inservice Test Plan	7
73DP-9XI05	Check Valve Condition Monitoring Program	2
73ST-9SI05	Leak Test of HPSI/LPSI Containment Isolation Check Valves	16
90DP-0IP10	Condition Reporting	15

Drawings

Number	Title	Revision
02-M-SIP-002	Safety Injection P&ID	26
13-N001-2101-00028	(BW/IP 77700) 3 inch SWING CHK VLV 1521# CRES SI-113, 123, 144, 143, 522, 523, 533	16
13-10407-N001-21.01-29-7	(BW/IP 77720) 4 inch SWING CHK VLV 1521# CRES RC-244	
13-10407-N001-11.04-37-8	(BW/IP 77790) 12 inch SWING CHK VLV 1521# CRES SI-114, 124, 134, 144	
13-N001-1104-00018	(BW/IP 77810) 14 inch SWING CHK VLV 1521# CRES SI-215, 217, 225, 27, 35, 37, 45, 47	15
73ST-9XI33 page 49 of 54	HPSI PUMP AND CHECK VALVE FULL FLOW TEST, HHSI Full Flow Test Lineup App G-simplified Drawing	39
01-M-SIP-002	Safety Injection and Shutdown Cooling P&ID	23
01-M-SIP-001	Safety Injection and Shutdown Cooling P&ID	24
01-M-CHP-001	Charging and Volume Control System P&ID	21

01-M-CHP-002	Charging and Volume Control System P&ID Sheet 1 of 2	40
01-M-CHP-003	Charging and Volume Control System P&ID	36

CRDRs

160256	23322802	2352119	2704507	29307742	29337292	2941837	920412
232280	335098	250097	2716763	932554	933731	2942318	930149

Work Orders

2361978	2615568	2764987	2880399	2934548
2380399	2716741	2860076	2864185	571081
2575362				

Manuals:

Number	Title	Revision
13-VTD-N383-0023-3	BW/IP Operation and Maintenance Manual for 1521 Pound Stainless Steel swing check valves [PUB. # OMM1059]	3
13-VTD-N383-00001	Vendor Technical Manual for Nuclear Valve Division Borg Warner Valves,	7
	Safety Injection Design Basis Manual	23

LERs

1998-006-01 PVNGS Unit 1 Safety Injection Discharge Check Valve Reverse Flow

2000-005-01 PVNGS 4 inch BW HPSI Discharge Check Valve 2PSIBV405 Failed Surveillance Test

2000-006-01 PVNGS BW 14 inch SIT 2B Outlet Check Valve 2PSIEV225 Failed Surveillance Test - Stuck Open

NRC Inspection Reports
Inspection Report 50-528/98-14; 50-529/98-14; 50-530/98-14
Inspection Report 50-528/01-03; 50-529/01-03; 50-530/01-03
Inspection Report 50-528/06-03; 50-529/06-03; 50-530/06-03

Operating Experience

10 CFR Part 21 NOTIFICATION Reference No. CFRN-9301, (BW Part 21 on Part No. 75580 check valves disc tilting into seat)

NRC IN 89-62,Malfunction of BW Pressure Seal Bonnet Check Valves Caused by Vertical Misalignment of Disk

NRC Information Notice No. 90-03, Malfunction of BW Bolted Bonnet Check Valves Caused By Failure of the Swing Arm

Significant Experience Report 28-89, Check Valve Failures

Miscellaneous

ASME/ANSI OMa-1988 Addenda to ASME/ANSI OM-1987 Operation and Maintenance of Nuclear Power Plants

Calculation, 13-MC-SI-503, Safety Injection System Train A, Revision 0

EPRI NMAC Application Guide for Check Valves, NP-5479

EPRI Check Valve Maintenance Guide, TR-100857s

EPRI Guide for the Application and Use of Valves in Power Plant Systems, NP-6516

FLOWSERVE Field Service Report, Dated 10/25/06, PVNGS Unit 1 SI-134 BW 12" 1521# Swing Check Valve

FLOWSERVE Field Service Report, Dated 11/03/06, PVNGS Unit 1 SI-134 BW 12" 1521# Swing Check Valve

PVNGS Engineering Action Request 89-1931 issued 1/26/1990 with IN 89-62 Response

PVNGS Maintenance Rule System Basis

PVNGS Calculation 13-MC-SI-503, Safety Injection System - Train A, Overpressure of LPSI Piping due to Failure of Check Valve V134

Section 4OA3: Followup of Events and Notices of Enforcement Discretion

Procedures

Number	Title	Revision
78OP-9FX03	Spent Fuel Handling Machine	36
78OP-9FX03	Spent Fuel Handling Machine	37
40OP-9MT02	Main Turbine	53
4OEP-9EO02	Reactor Trip	7

CRDRs

2654704	2654642	2932074	2912694	2913232

Work Orders

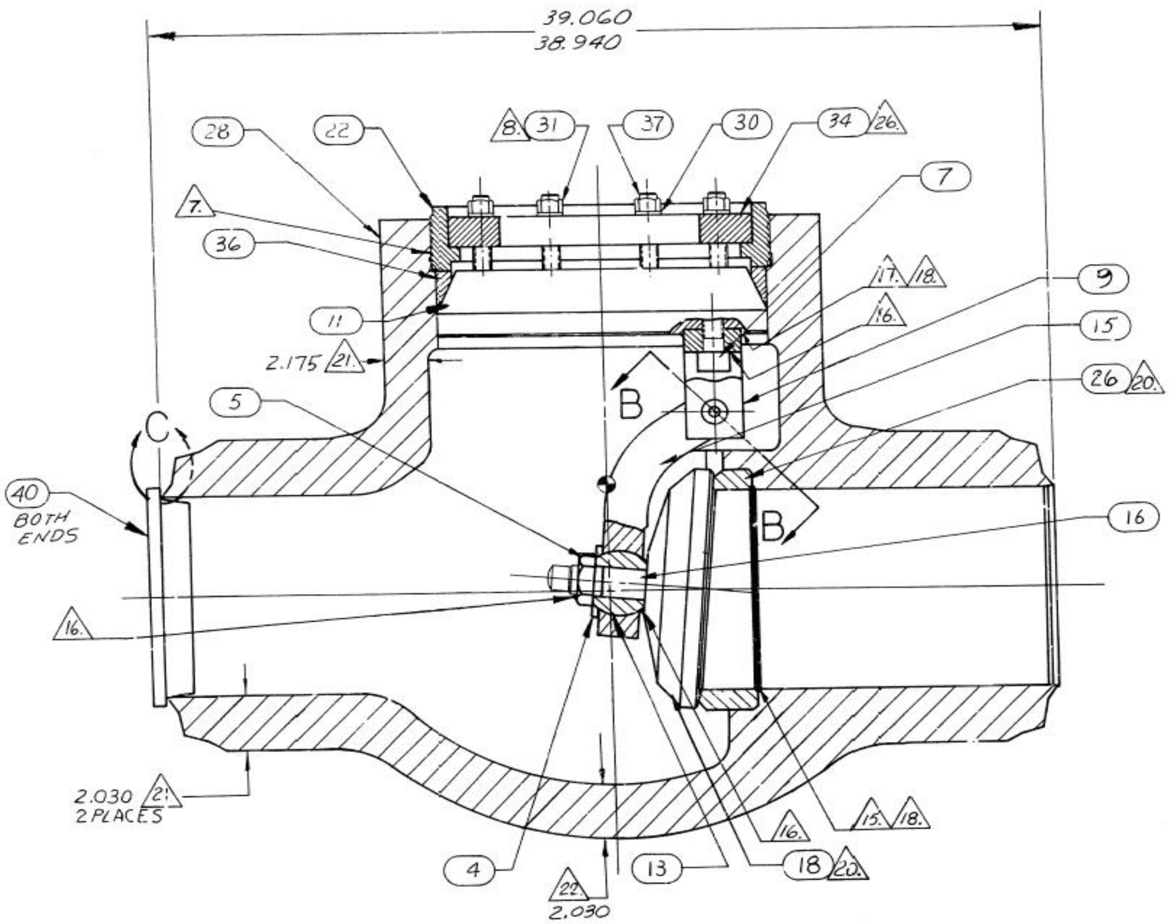
2936427   2912696

Miscellaneous

Event Notification 42938

Unit 1 Operations Logs

Unit 3 Operations Logs



SECTION A-A

The disc assembly for this Borg Warner swing-check valve consists of the following parts:

Item	Part	P/N	Material
4	Washer	1 3/8" Type A	316 CRES
5	Nut	1 3/8"-12UNF	ASTM A194, Grade 8M
13	Ball (spherical bearing)	72114	Stellite #6B
15	Swing Arm	75497	17-4PH material (AMS 5398)
16	Stud	72108	ASTM A276, Type 316A
18	Disc	76865	ASME SA182, Type 316

LIST OF ACRONYMS

AFW	auxiliary feedwater
ASME	American Society of Mechanical Engineers
BW	Borg Warner
CAP	corrective action program
CEA	control element assembly
CEAC	control element assembly calculator
CFR	*Code of Federal Regulations*
CPC	core protection calculator
CRDR	condition report/disposition request
CS	containment spray
DFWO	deficiency work order
DMWO	design modification work order
EAR	engineering action request
ECCS	emergency core cooling system
EDC	engineering design change
EDG	emergency diesel generator
EER	engineering evaluation request
EPRI	Electric Power Research Institute
FOSAR	foreign object search and retrieval
GDC	General Design Criteria
HPSI	high pressure safety injection
LER	licensee event report
LPSI	low pressure safety injection
NAD	nuclear assurance department
NATM	nuclear administration and technical manual
NCV	noncited violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OD	operability determination
PM	preventive maintenance
PVAR	Palo Verde action request
RCS	reactor coolant system
RWT	refueling water tank
SDC	shutdown cooling
SFHM	spent fuel handling machine
SI	safety injection
SIT	safety injection tank
SSC	structure, system, and component
TD	technical document
TS	technical specifications
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WECC	Western Electricity Coordinating Council
WM	work mechanism
WO	work order
WSL	work scope library