UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

January 27, 2003

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

SUBJECT: PALO VERDE NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 50-528/02-06; 50-529/02-06; 50-530/02-06

Dear Mr. Overbeck:

On December 28, 2002, the NRC completed an inspection at your Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility. The enclosed report documents the inspection findings which were discussed with members of your staff on January 3, 2003, and as described in Section 4OA6.

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 license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This inspection report documents one NRC-identified finding and one self-revealing finding of very low safety significance. Both findings were determined to involve violations of NRC requirements. Additionally, licensee-identified violations are listed in Section 4OA7. Because of their very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations (NCVs) consistent with Section V1.A of the NRC Enforcement Policy.

If you contest the violation or significance of these NCVs, 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; 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 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response 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/

Linda Joy Smith, Chief
Project Branch D
Division of Reactor Projects

Dockets: 50-528
50-529
50-530
Licenses: NPF-41
NPF-51
NPF-74

Enclosure:
NRC Inspection Report
50-528/02-06; 50-529/02-06; 50-530/02-06

cc w/enclosure:
Steve Olea
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

Douglas K. Porter, Senior Counsel
Southern California Edison Company
Law Department, Generation Resources
P.O. Box 800
Rosemead, California 91770

Chairman
Maricopa County Board of Supervisors
301 W. Jefferson, 10th Floor
Phoenix, Arizona 85003

Aubrey V. Godwin, Director
Arizona Radiation Regulatory Agency
4814 South 40 Street
Phoenix, Arizona 85040

Craig K. Seaman, Director
Regulatory Affairs/Nuclear Assurance
Palo Verde Nuclear Generating Station
Mail Station 7636
P.O. Box 52034
Phoenix, Arizona 85072-2034

Hector R. Puente
Vice President, Power Generation
El Paso Electric Company
2702 N. Third Street, Suite 3040
Phoenix, Arizona 85004

Terry Bassham, Esq.
General Counsel
El Paso Electric Company
123 W. Mills
El Paso, Texas 79901

John W. Schumann
Los Angeles Department of Water & Power
Southern California Public Power Authority
P.O. Box 51111, Room 1255-C
Los Angeles, California 90051-0100

John Taylor
Public Service Company of New Mexico
2401 Aztec NE, MS Z110
Albuquerque, New Mexico 87107-4224

Jarlath Curran
Southern California Edison Company
5000 Pacific Coast Hwy. Bldg. DIN
San Clemente, California 92672

Robert Henry
Salt River Project
6504 East Thomas Road
Scottsdale, Arizona 85251

Brian Almon
Public Utility Commission
William B. Travis Building
P.O. Box 13326
1701 North Congress Avenue
Austin, Texas 78701-3326

Technical Services Branch Chief
FEMA Region IX
1111 Broadway, Suite 1200
Oakland, California 94607-4052

Electronic distribution by RIV:
Regional Administrator **(EWM)**
DRP Director **(ATH)**
DRS Director **(DDC)**
Resident Inspector **(NLS)**
Branch Chief, DRP/D **(LJS)**
Senior Project Engineer, DRP/D **(JAC)**
Project Engineer, DRP/D **(ELC1)**
Staff Chief, DRP/TSS **(PHH)**
RITS Coordinator **(NBH)**
W. A. Maier, RSLO **(WAM)**
Scott Morris **(SAM1)**
Dale Thatcher **(DFT)**

R:_PV\2002\PV2002-06RP-NLS.wpd

RIV:RI:DRP/D	SRI:DRP/D	PE:DRP/D	C:DRS/PSB	C:DRS/EMB
GGWarnick	NLSalgado	ELCrowe	TPruett	CSMarschall
T-LJSmith	***T-LJSmith***	***/RA/***	***E-LJSmith***	***E-LJSmith***
01/27/03	01/27/03	01/27/03	01/27/03	01/27/03

D:DRP/D				
LJSmith				
/RA/				
01/27/03				

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528 50-529 50-530
Licenses:	NPF-41 NPF-51 NPF-74
Report No:	50-528/02-06 50-529/02-06 50-530/02-06
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	September 22 through December 28, 2002
Inspectors:	N. L. Salgado, Senior Resident Inspector, Project Branch D G. G. Warnick. Resident Inspector, Project Branch D E. L. Crowe, Project Engineer, Project Branch D L. T. Ricketson, P.E., Senior Health Physicist, Plant Support Branch W. M. McNeill, Senior Reactor Inspector, Engineering and Maintenance Branch P. J. Elkmann, Emergency Preparedness Inspector, Plant Support Branch
Accompanying Personnel:	A. Passarelli, General Engineer (Intern), Project Branch D
Approved By:	Linda Joy Smith, Chief, Project Branch D Division of Reactor Projects
Attachment:	Supplemental Information

SUMMARY OF FINDINGS

Palo Verde Nuclear Generating Station, Units 1, 2, and 3
NRC Inspection Report 50-528/02-06; 50-529/02-06; 50-530/02-06

IR 05000528-02-06, IR 05000529-02-06, IR 05000530-02-06, on 9/22/02 - 12/28/02, Arizona Public Service Company; Palo Verde Nuclear Generating Station, Units 1, 2, and 3; personnel performance during nonroutine evolutions and event followup.

The inspection was conducted by the resident inspectors, a project engineer, an emergency preparedness inspector, a senior health physicist, and a senior reactor inspector. The inspection identified two issues that were evaluated by the significance determination process in Inspection Manual Chapter 0609, and determined to have very low safety significance (Green). 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.

Cornerstone: Initiating Events

- Green. A noncited violation of 10 CFR 50.59 and Technical Specification 5.4.1(a) was identified for failing to perform a required safety evaluation and for inappropriately revising Procedure 40AO-9ZZ05, "Loss of Letdown," Revision 9, in February 1996.

  Procedure 40AO-9ZZ05 was revised to direct operators to allow charging to increase pressurizer level from 55 percent to 70 percent based on a calculation that assumed the plant was tripped. As a result, the procedure was inadequate for operation at 100 percent power in that the procedure directed operators to allow charging to increase pressurizer level above the Technical Specification limit on pressurizer level in MODES 1, 2, and 3 of 56 percent. When the procedure was used at 100 percent power on October 15, 2002, the probability or likelihood of malfunction of the pressurizer safety valves, equipment previously evaluated in the safety analysis report, increased.

  The violation was of more than minor safety significance because the inadequate procedure placed the plant in a condition that increased the likelihood that a loss of heat removal accident would cause reactor coolant to pass through the pressurizer safety valves thus causing damage to these valves. The finding is of very low safety significance because of the short duration of the condition and availability of mitigating system components. This violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Requests 2560477 and 2580246 (Section 1R14).

Cornerstone: Mitigating Systems

- Green. A noncited violation was identified for failure to comply with 10 CFR Part 50, Appendix B, Criterion III, related to the design control measures used in the extension of the control element assembly design lifetime. The licensee used inadequate design control measures when implementing a design change to extend control element assembly lifetime beyond the Updated Final Safety Analysis design lifetime of 10 years. Specifically, the licensee failed to identify that the control element assembly lifetime limit code had not been benchmarked with experimental data from feltmetal fingers at high fluence levels which resulted in an overestimation of control element assembly lifetime. This issue was entered into the licensee’s corrective action program as Condition Report/Disposition Request 2377444.

This finding is greater than minor because it affected the mitigating system cornerstone objective of reactivity control, in that the issue resulted in plant operations with degraded control element assemblies. The finding is of very low safety significance because it only affects the mitigation systems cornerstone and is a deficiency that did not result in the actual loss of the safety function (Section 4OA3.4).

- Violations of very low 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. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

Report Details

Summary of Plant Status

Unit 1 operated at essentially full power until September 27, 2002, when the unit was shutdown for Refueling Outage 1R10. On October 31, during power ascension following the refueling outage, the unit was shutdown due to exceeding steam generator chemistry action levels (Section 1R14). The unit reached 69 percent after restoration of steam generator chemistry when management directed a unit shutdown on November 10, to troubleshoot elevated shutdown cooling (SDC) line Train A vibrations. During the shutdown, the unit tripped from 68 percent due to a low departure from nucleate boiling ratio (DNBR) trip (Section 1R14). The unit was returned to essentially full power on November 14, and remained at that level until December 7, when power was reduced to 77 percent to support an offsite transmission line outage. The unit was returned to essentially full power on December 8, and remained there for the duration of this inspection period.

Unit 2 operated at essentially full power for the duration of this inspection period.

Unit 3 operated at essentially full power for the duration of this inspection period.

1. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity
[REACTOR - R]

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed sections of the Updated Final Safety Analysis Report (UFSAR), the Design Basis Manual, and Specification 13-EN-306, "Installation Specification for Cable Splicing and Terminations," Revision 8, to determine if the gas turbine generators (GTGs) were designed to remain functional during adverse weather related risks identified for the site (Units 1 and 2).

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors completed a partial walkdown of the systems listed below to verify proper equipment alignment. This inspection included a review of the applicable plant procedures, plant drawings, outstanding modifications, work orders (WO), and condition report/disposition requests (CRDRs). The inspectors verified the following: (1) all valves were properly aligned; (2) there was no leakage that could affect operability; (3) electrical power was available as required; (4) major system components were properly labeled, lubricated, and cooled.

- October 2, 2002, SDC system Trains A and B (Unit 1)
- December 4, 2002, essential chilled water Train A (Unit 1)

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q)

a. Inspection Scope

The inspectors conducted tours of the areas listed below that are important to reactor safety and referenced in the Prefire Strategies Manual to evaluate conditions related to licensee control of transient combustibles and ignition sources; the material condition, operational status, and operational lineup of fire protection systems, equipment and features; and the fire barriers used to prevent fire damage from propagation of potential fires.

- October 1, 2002, Containment building - all accessible elevations (Unit 1)
- November 6, 2002, Condensate storage pump house and tunnel (Unit 3)
- November 14, 2002, Auxiliary building 40-foot and 51-foot 6-inch elevations (Unit 1)
- November 20, 2002, Diesel generator building - all accessible elevations (Unit 2)
- December 11, 2002, Main steam support structure 80-foot, 100-foot, 120-foot, and 140-foot elevations (Unit 2)

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

Performance of Nondestructive Examination (NDE) Activities Other than Steam Generator Tube Inspections

The inspectors observed licensee and contractor NDE personnel perform the ASME Code Section XI examinations listed below:

System	Component/Weld Identification	Examination Method
Safety Injection	Pipe to Elbow Zone 94 Weld 74-37	Liquid Penetrant Examination Ultrasonic Examination
Safety Injection	Pipe to Elbow Zone 94 Weld 74-38	Liquid Penetrant Examination Ultrasonic Examination

During the performance of each examination, the inspectors verified that the licensee used the correct NDE procedure, the licensee met the requirements specified in the procedure, and the licensee used properly calibrated test instrumentation or equipment. The inspectors could not verify that the licensee compared indications revealed by the examinations against the previous outage examination reports because the licensee had just added these examinations to the inservice inspection program.

The inspectors found there were no welding repairs performed under Section III of the ASME Code for Classes 1 and 2 components since the last outage.

The inspectors reviewed two ASME Code Section XI valve repair/replacement activities (WOs 2417233 and 2470872) on replacement of piping on the steam generator and replacement of valve plugs in the safety injection system. The licensee performed welding on the piping replacement only. The inspectors verified that the replacements met ASME Code requirements.

Steam Generator Tube Inspection Activities

At the time of this inspection, the inspectors found the scope of in-situ pressure testing had not been established. The inspectors verified that the operational assessment predictions of tube plugging appeared to be the same as experienced in the past. The inspectors also verified the licensee’s eddy current examination scope and expansion criteria met Technical Specifications, industry guidelines, and commitments to the NRC.

The inspectors found the licensee inspected the areas of potential degradation based on site-specific and industry experience. The inspectors verified that the licensee compared flaws detected during the current outage against the previous outage data. The inspectors reviewed the repair criteria used. Plugging had not begun at the time of this inspection. The inspectors also reviewed the leakage history for the steam generators. The inspectors found the licensee used eddy current probes and equipment properly qualified for the expected types of tube degradation. The inspectors observed the collection and analysis of eddy current data by licensee personnel that was performed to evaluate a possible loose part.

Identification and Resolution of Problems

The inspectors reviewed the CRDRs issued during the past year and reviewed in detail a sample of 12 CRDRs on inservice and steam generator eddy current inspection activities. The inspectors verified that the licensee identified, evaluated, corrected, and trended problems.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11Q)

a. Inspection Scope

On November 14, 2002, the inspectors observed operations crew performance during evaluated simulator Scenario SES-0-02-B-01, "Power Reduction/Main Turbine Trip - Load Rejection/Reactor Trip," dated October 9, 2002. The inspectors evaluated the simulator scenario, the crew performance, and the evaluator critique sessions conducted following the completion of the simulator scenario. The inspectors verified that the examinations were in conformance with NUREG 1021, “Operator Licensing Examiner Standards,” ES-604, “Dynamic Simulator Requalification Examination,” and management expectations.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope

The inspectors verified the licensee's appropriate handling of structure, system, and component performance or condition problems during review of the following equipment failures. Additionally, the inspectors evaluated the equipment failures to verify that licensee personnel properly implemented the requirements of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants”:

- September 29, 2002, unplanned loss of SDC Train A caused by failure of Valve 1JSIAUV0651 reported in CRDR 2557486 (Unit 1)
- October 21, 2002, inability to stop auxiliary feedwater Pump A when Valve 2JSGUV0134 failed to close reported in CRDR 2562736 (Unit 2)

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

During the inspection period the inspectors reviewed daily and weekly work schedules to determine when risk-significant activities were scheduled. The inspectors reviewed risk evaluations and overall plant configuration control for selected activities to verify compliance with Procedure 30DP-9MT03, "Assessment and Management of Risk When Performing Maintenance in Modes 1 - 4," Revision 6. The inspectors discussed emergent work issues with work control personnel and reviewed the potential risk impact of these activities to verify that the work was adequately planned, controlled, and executed. The inspectors verified that plant configurations allowed by the plant configuration risk indicator matrix were consistent with actual plant conditions during maintenance. The specific activities reviewed were associated with planned and emergent maintenance on:

- October 21, 2002, failure of auxiliary feedwater turbine steam supply Valve 2JSGA-UV134 to close during the performance of Procedure 73ST-9AF02, "AFA-P01 - Inservice Test," Revision 24 (Unit 2)

- November 27, 2002, troubleshoot and repair termination due to identified hot spot in main transformer control cabinet (Unit 1)

- December 3, 2002, failure of feedwater isolation Valve 2JSGBUV0137 to stroke during 90 percent exercise test (Unit 2)

- December 14, 2002, cooling tower makeup and blowdown leak and availability of long-term makeup to essential spray ponds (Unit 3)

- December 19, 2002, addition of oil to reactor coolant Pump A due to upper motor bearing oil level downward trend (Unit 3)

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Evolutions (71111.14, 71153)

.1 Nonroutine Evolutions

a. Inspection Scope

For the nonroutine evolutions described below, the inspectors reviewed operators logs and plant computer data and/or observed operator performance to determine what occurred and how the operators responded, and to determine if the response was in accordance with plant procedures:

- On September 27-28, 2002, inspectors reviewed and observed performance and response during portions of the Unit 1 shutdown to start Refueling Outage 1R10. These activities were conducted in accordance with Procedure 40DP-9ZZ05, "Power Operation," Revision 73.

- On October 30, 2002, inspectors observed performance and response during the Unit 1 reactor startup following Refueling Outage 1R10. These activities were conducted in accordance with Procedure 40OP-9ZZ02, "Initial Reactor Startup Following Refuelings," Revision 26.

- On October 31, 2002, inspectors reviewed the response to a Unit 1 shutdown from 19 percent power. The shutdown was procedurally required due to high secondary chemistry sulfate levels in both steam generators.

- On November 10, 2002, the inspectors reviewed and observed performance and response during portions of a Unit 1 automatic trip on low DNBR due to control element assembly (CEA) subgroup deviation from approximately 64 percent power. A downpower from 68 percent power was in progress to correct the elevated vibrations on SDC line Train A. The control room operators also entered abnormal operating Procedure 40AO-9ZZ05, "Loss of Letdown," Revision 10, due to loss of letdown which occurred posttrip. The loss of letdown occurred when regenerative heat exchanger outlet isolation Valve 1JCHBUV0523 closed on low nuclear cooling flow. Letdown was reestablished in approximately 10 minutes. The licensee determined that the root cause of the CEA deviation was a failed optical isolation card in the control system for CEA 48.

- On November 12, 2002, inspectors observed performance and response during the Unit 1 reactor startup following work scheduled to correct vibration problems with SDC line Train A. These activities were conducted in accordance with Procedure 40OP-9ZZ03, "Reactor Startup," Revision 29.

b. Findings

No findings of significance were identified.

.2 Unit 3 - Loss of Letdown

a. Inspection Scope

On October 15, 2002, the inspectors responded to the Unit 3 control room to evaluate operator response to a loss of letdown. The inspectors interviewed operators, reviewed operator logs, and plant computer data, to verify that operator response was in accordance with plant procedures. The inspectors also reviewed Technical Specification entries for the event.

Introduction:

A Green NCV was identified for failing to perform a required safety evaluation and for inappropriately revising Procedure 40AO-9ZZ05, "Loss of Letdown," Revision 9, in February 1996. The inadequate procedure which provided guidance for operators to allow charging to increase pressurizer level to 70 percent which is above the Technical Specification limit of 56 percent. This was determined to be a violation of 10 CFR 50.59 and Technical Specification 5.4.1(a).

Description:

On October 15, 2002, letdown Control Valve 3JCHELV0110P began operating erratically during preparations to perform moderator temperature coefficient testing on Unit 3. This resulted in regenerative heat exchanger to letdown heat exchanger relief Valve 3JCHNPSV345 lifting to relieve excess letdown system pressure and subsequently failing to close. The control room operators isolated the letdown system from the reactor coolant system (RCS) and entered Procedure 40AO-9ZZ05, "Loss of Letdown," Revision 9. The operators entered Appendix C, "Extended Operations Without Letdown," of Procedure 40AO-9ZZ05, which allowed for continued operation with letdown isolated. Step 4 of Appendix C directs the operators to isolate controlled bleedoff on all standby reactor coolant pumps, close seal injection flow control valves, and place all charging pumps in PULL-TO-LOCK when the control room supervisor determines seal injection and charging are to be stopped, or pressurizer level rises to 70 percent. Since all reactor coolant pumps were operating and control bleedoff was needed, pressurizer level lowered at a slow rate. Charging pumps were operated as needed per Step 5 of Appendix C to control pressurizer level in the band allowed by the loss of letdown procedure. Over a 6-hour period, the control room operators allowed pressurizer level to increase above 56 percent 4 times. The durations were 1 hour and 23 minutes, 1 hour and 8 minutes, 50 minutes, and 47 minutes.

The inspectors found that Procedure 40AO-9ZZ05 was revised in February of 1996 to direct operators to allow charging to increase pressurizer level from 55 percent to 70 percent based on a calculation that assumed the plant was tripped. As a result the procedure was inadequate for operation at 100 percent power in that the procedure directed operators to allow charging to increase pressurizer level above the Technical Specification limit on pressurizer level in MODES 1, 2, and 3 of 56 percent. When the procedure was used at 100 percent power on October 15, 2002, the probability of malfunction of the pressurizer safety valves, equipment previously evaluated in the safety analysis report, increased.

Analysis:

The inspectors determined that this finding had a potential impact on safety in that excessive pressurizer level could have resulted in the failure of the pressurizer safety valves in the event of a loss of heat removal type accident and is, therefore, greater than minor. The Technical Specification Bases 3.4.9 states that the maximum steady state water level limit has been established to ensure that a liquid to vapor interface exists to permit RCS pressure control during an anticipated design-basis transient. The imit was selected to prevent filling the pressurizer (water solid) for anticipated design basis transients, thus ensuring that pressure relief devices (pressurizer safety valves) can control pressure by steam relief rather than water relief. If the level limits were exceeded prior to a transient that creates a large pressurizer insurge volume leading to water relief, the maximum RCS pressure might exceed the Safety Limit of 2750 psia, thus increasing the probability of malfunction of equipment previously evaluated in the safety analysis report.

This is considered to be a primary system LOCA initiator contributor in the initiating event cornerstone. The potential LOCA was evaluated utilizing Inspection Manual Chapter (IMC) 0609, "Significance Determination Process." Phases 1 and 2 worksheets were performed to characterize the safety significance. The event duration was only 6 hours, thus, the exposure time was less than 3 days. The analysis assumed that no mitigating equipment was degraded and no credit was given for operator recovery (pressurizer safety valves were assumed to be permanently damaged by water flow through the valves). The analysis utilized the small break LOCA work sheet which resulted in a very low safety significance (Green) with the dominant core damage sequence being Cutset 6.

Enforcement:

10 CFR 50.59, “Changes, tests, and experiments,” in effect in February 1996 does not allow the licensee to change procedures described in the safety analysis report without Commission approval, if the change increases the probability of occurrence of malfunction of equipment important to safety previously evaluated in the safety analysis report.

10 CFR 50.59, “Changes, tests, and experiments,” in effect on October 15, 2002 does not allow the licensee to change procedures described in the safety analysis report without Commission approval, if the change results in more than a minimal increase in the likelihood of occurrence of malfunction of a component important to safety previously evaluated in the safety analysis report.

Both versions of 10 CFR 50.59 also require the licensee to maintain records of their written safety evaluations that provide the basis for determining that the change is allowed.

Technical Specification 5.4.1 states, "Written procedures shall be established, implemented, and maintained covering the following activities: (a) The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978; . . . ." Regulatory Guide 1.33 directs licensees to ensure minimum procedural coverage of plant operating activities and provides Appendix A, which is a listing of typical safety-related activities that should be covered.

Contrary to the above requirements, a change was made February 1996, to Procedure 40AO-9ZZ05, "Loss of Letdown," Revision 9, Appendix C, Step 4, which directed operators to allow pressurizer level to increase to 70 percent, thus increasing the probability or likelihood of malfunction of the pressurizer safety valves. This revision was made without the required safety evaluation.

This violation is being treated as a noncited violation (50-530/02-06-01) consistent with Section VI.A of the NRC Enforcement Policy. This issue was entered into the licensee's corrective action program as Condition Report/Disposition Requests 2560477 and 2580246.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors evaluated the operability determinations listed below for technical adequacy and assessed the impact of the condition on continued plant operation. Additionally, the inspectors reviewed Technical Specification entries, CRDRs, and equipment issues to verify that operability of plant structures, systems, and components were maintained or that Technical Specification actions were properly entered.

- September 29, 2002, high vibration on Valve 1JSIAUV0651 and associated SDC suction line as reported in CRDRs 2557486 and 2373544 (Unit 1)

- October 27, 2002, Operability Determination 255, Revision 0, assessment of power supply inverter to SDC isolation valve inverter fast shutdown during Valve 1JSICUV0653 stroke and it's applicability to the other SDC isolation valves reported in CRDR 2560126 (Units 1, 2, and 3)

- November 20, 2002, control air leakage from the fuel cylinder control valve identified during restoration of the diesel generator Train A from a maintenance outage as reported in CRDR 2569164 (Unit 2)

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19, 71153)

a. Inspection Scope

The inspectors observed and/or evaluated the results from the following postmaintenance tests to determine whether the test adequately confirmed equipment operability. The inspectors also verified that postmaintenance tests satisfied the requirements of Procedure 30DP-9WP04, "Postmaintenance Retest Development," Revision 13.

- October 11, 2002, WO 2559804, following maintenance on emergency diesel generator Train A (Unit 1)

- October 16, 2002, WO 2558826, following corrective maintenance on SDC Valve 1JSIAUV0651 (Unit 1)
- November 20, 2002, various WOs, following essential spray pond, emergency diesel generator, essential chilled water, essential cooling water, and containment spray Train A on-line outage (Unit 2)

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

Unit 1 - Tenth Refueling Outage

.1 Review of the Unit 1 Outage Plan

a. Inspection Scope

The inspectors reviewed the licensee's outage risk assessment, Palo Verde Unit 1 Tenth Refueling Shutdown Risk Assessment, Revision 1, to verify that the licensee appropriately considered risk in planning and scheduling the outage activities.

The inspectors primarily focused on the following activities:

- Midloop and reduced inventory operations
- Spent fuel pool cooling during fuel offload/reload and core offloaded
- Reactor vessel head inspections

b. Findings

No findings of significance were identified.

.2 Monitoring of Shutdown Activities

a. Inspection Scope

The inspectors reviewed plant data records and unit operations logs and conducted interviews with licensed operators to assess the licensee's compliance with Technical Specification plant cooldown limits during the Unit 1 plant cooldown.

b. Findings

No findings of significance were identified.

.3 Control of Outage Activities

a. Inspection Scope

The inspectors reviewed plant conditions and observed selected refueling outage activities through the outage to verify that the licensee maintained the plant in a configuration consistent with the requirements of Technical Specifications and with the assumptions of the outage risk assessment. The inspectors verified that emergent issues were properly assessed for their impact on plant risk.

Electrical power availability was periodically verified to meet Technical Specification requirements and outage risk-assessment recommendations. Control room operators were interviewed to determine if they were cognizant of plant conditions. The inspectors reviewed equipment clearance activities, controls for reactivity management, and RCS inventory.

b. Findings

No findings of significance were identified.

.4 Clearance Activities

a. Inspection Scope

The inspectors reviewed the following equipment clearances:

- ID 77458, "Examine Diesel Engine General Tear Down and Inspections"
- ID 81340, "Half Pipe Permit"
- ID 88214, "PCN-V118 SFP Inventory Control"

b. Findings

No findings of significance were identified.

.5 Reduced Inventory and Midloop

a. Inspection Scope

On October 1-2 and October 23-24, 2002, the inspectors observed, in part, Unit 1 midloop activities to verify that the licensee had appropriately considered the risk associated with this activity. The inspectors reviewed the licensee’s response to Generic Letter 88-17, "Loss of Decay Heat Removal (10 CFR 50.54)," and verified that licensee commitments had been properly translated into procedures. The inspectors also verified that multiple sources of electrical power, multiple reactor vessel level indications, and multiple RCS temperature indications were available. The inspectors observed licensee compliance with the following procedures:

- 40OP-9ZZ16, "RCS Drain Operations," Revision 31
- 40OP-9ZZ20, "Reduced Inventory Operations," Revision 4

b. Findings

No findings of significance were identified.

.6 Refueling Activities

a. Inspection Scope

The inspectors observed portions of core off-load and core reload activities to determine if these activities were conducted in accordance with the Technical Specification and administrative procedures. Refueling was conducted using Procedure 72IC-9RX03, "Core Reloading," Revision 18.

b. Findings

No findings of significance were identified.

.7 Monitoring of Heatup and Startup Activities

a. Inspection Scope

The inspectors reviewed control room and unit logs to verify that the Unit 1 startup was conducted in compliance with Technical Specification and administrative requirements. The inspectors accompanied licensee personnel to verify performance of Procedure 40ST-9ZZ09, "Containment Cleanliness Inspection," Revision 5, to assess containment cleanliness and materiel condition of components.

b. Findings

No findings of significance were identified.

.8 Identification and Resolution of Problems

a. Inspection Scope

The inspectors screened CRDRs that documented problems identified during the Unit 1 outage to verify that problems were identified at an appropriate threshold.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed the performance of and/or reviewed documentation for the following surveillance tests. Applicable test data was reviewed to verify whether they met Technical Specifications, UFSAR, and procedure requirements. Also, the inspectors verified that the testing effectively demonstrated that the systems were operationally ready, capable of performing their intended safety functions, and that identified problems were entered into the corrective action program for resolution.

- September 24, 2002, Procedure 36ST-9SB32, "PPS Input Loop Calibration for Parameter 20, LO RWT Level," Revision 10 (Unit 1)

- December 2, 2002, Procedure 73ST-9EW01, "Essential Cooling Water Pumps - Inservice Test," Revision 16 (Unit 1)

- December 12, 2002, Procedure 74OP-9SS01, "Primary Sampling Instructions," Revision 21 (Unit 3)

- December 13, 2002, Procedure 40ST-9RC02, "ERFDADS (Preferred) Calculation of RCS Water Inventory," Revision 21 (Units 1, 2, and 3)

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors evaluated the following temporary modification and associated 10 CFR 50.59 screening. The inspectors reviewed this against the system design-basis documentation and verified that the modification did not adversely affect system operability or availability. Additionally, the inspectors verified that the installation was consistent with applicable modification documents and conducted with adequate configuration control. The inspectors observed the installation of and/or reviewed documentation for the following T-Mod:

- T-Modification 2553633, "Backup Heater Setpoint Change," (Unit 2)

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors performed an in-office review of Revision 26 to the Palo Verde Nuclear Generating Station Emergency Plan, submitted July 23, 2002, against the previous revision and 10 CFR 50.54(q) to determine if the revision decreased the effectiveness of the emergency plan.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY
Cornerstone: Occupational Radiation Safety [OS]

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

To review and assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, and high radiation areas, the inspectors interviewed radiation workers and radiation protection personnel involved in high dose rate and high exposure jobs during Refueling Outage 1R10. The inspectors also conducted plant walkdowns within the radiologically controlled area and conducted independent radiation surveys of selected work areas. The inspectors focused on work activities with the potential for significant dose, such as the removal of Check Valve RCV244 (Radiation Exposure Permit 1-1285A), hot leg nozzle removal, (Radiation Exposure Permit 1-3301C), primary-side steam generator maintenance (Radiation Exposure Permit 1-3306D), and reactor coolant pump maintenance (Radiation Exposure Permit 1-3319D). The following items were reviewed and compared with regulatory requirements:

- Area postings and other access controls for airborne radioactivity areas, radiation areas, and high radiation areas in both the containment building and balance of plant

- Radiation exposure permits and radiological surveys involving airborne radioactivity areas and high radiation areas

- Formal prejob briefing presented before removing Check Valve RCV244

- Dosimetry placement when work involved a significant dose gradient

- High radiation area key controls

- Controls involved with the storage of highly radioactive items in the spent fuel pool
- Selected corrective action documents involving access controls to radiologically significant areas (2379904, 2381477, 2412498, 2417609, 2432686, 2435418, 2435009, 2497036, and 3500934)
- Audit 2001-007, "Radiation Protection/Radwaste Programs," and evaluations (ER 01-0099, 01-0129, 01-298, 01-312, 01-324, 01-400, 02-101, and 02-102) involving high radiation area controls

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification (71151)

.1 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors reviewed corrective action program records involving locked high radiation areas (as defined in Technical Specification 5.7.2), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned exposure occurrences (as defined in NEI 99-02) for the past 12 months to confirm that these occurrences were properly recorded as performance indicators. Radiological controlled area entries with exposures greater than 100 millirems within the past 12 months were reviewed, and selected examples were examined to determine whether they were within the dose projections of the governing radiation exposure permits. Whole body counts or dose estimates were reviewed if the radiation worker received a committed effective dose equivalent of more than 100 millirems. Where applicable, the inspectors reviewed the summation of unintended deep dose equivalent and committed effective dose equivalent to verify that the total effective dose equivalent did not surpass the performance indicator threshold without being reported. Additionally, during routine plant status reviews, inspectors verified that locked high radiation areas were maintained locked.

b. Findings

No findings of significance were identified. The performance indicator remained in the licensee response band (Green).

.2 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors reviewed radiological effluent release program corrective action records, licensee event reports (LERs), and annual effluent release reports documented during the past four quarters to determine if any doses resulting from effluent releases exceeded the performance indicator thresholds (as defined in NEI 99-02). Additionally, during routine plant status reviews, inspectors screened plant incidents involving leaking pipes with radioactive liquids or gases to verify there were no unmonitored release pathways.

b. Findings

No findings of significance were identified. The performance indicator remained in the licensee response band (Green).

.3 RCS Activity (Units 1, 2, and 3)

a. Inspection Scope

The inspectors reviewed a random sample of the RCS activity data logs from December 2001 through November 2002 to verify the accuracy and completeness of the RCS specific activity reported for all three units.

b. Findings

No findings of significance were identified. The performance indicator remained in the licensee response band (Green).

.4 RCS Leakage (Units 1, 2, and 3)

a. Inspection Scope

The inspectors reviewed the licensee’s RCS leakage database from December 2001 through November 2002 to verify the accuracy and completeness of data used to calculate and report RCS leakage performance indicator for all three units.

b. Findings

No findings of significance were identified. The performance indicator remained in the licensee response band (Green).

4OA3 Event Follow-up (71153)

.1 (Closed) LER 50-528/2002-005-00: Inadequate surveillance test for time response testing of HI log power trip function.

On December 11, 2001, the licensee discovered that the procedure used to time response test the plant protection system log power trip circuitry did not meet Technical Specification Surveillance Requirements 3.3.1.13 and 3.3.2.5. Because each unit was operating in Mode 1 at the time, the Technical Specification for entering a limiting condition of operation did not apply. This Technical Specification violation was placed in the licensee's corrective action program and documented on CRDR 2448048. Actions to correct the test method and retest the log power trips were completed. Testing showed that the log power trips were able to function correctly. This issue constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC Enforcement Policy.

.2 (Closed) LER 50-530/2002-001-00: Technical Specification violation due to incorrect constant entered in the core operating limits supervisory system.

On January 16, 2002, reactor engineering personnel notified control room operators Unit 3 was operating with nonconservative values for the DNBR core operating limits supervisory system (COLSS) power operating limit (POL) margin. The error resulted in a condition where Unit 3 was operated with nonconservative values being displayed by COLSS for linear heat rate (LHR) and DNBR POL margins. Specifically, this error resulted in an indicated COLSS LHR and DNBR calculated POL margins that were 4 percent higher than it should have been. The licensee's review of the Unit 3 Cycle 10 core data determined that the minimum COLSS calculated POL was approximately 109 percent rated thermal in early November 2001. Reducing this value by 4 percent still yielded an acceptable margin in COLSS. The control room operators determined that the LHR and DNBR were not within specified limits for COLSS out of service and Condition B of Limiting Condition for Operations 3.2.1 and 3.2.4 were entered. Corrective action was taken to restore the COLSS constants. Also, Units 1 and 2 were verified to have the correct constants installed. This error did not impact the core protection calculator (CPC) system ability to generate a reactor trip signal when needed. This finding was documented in the licensees corrective action program as CRDR 2457102. This issue constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC Enforcement Policy.

.3 (Closed) LER 50-529/2002-002-00: Posttest constants entered in the CPC system.

On April 18, 2002, the licensee discovered that Unit 2 had operated with posttest instead of pretest values for the CPCs for DNBR and LPD uncertainty multipliers during postoutage power ascension testing. The licensee investigation determined that the CPCs were capable of performing their safety function at all times with the posttest valves installed. The inspectors reviewed the LER and no findings of significance were identified. This issue was entered into the licensee's corrective action program and documented on CRDR 2508991.

.4 (Closed) LER 50-528; 50-529; 50-530/2001-003-00: Technical Specification required shutdown due to degraded control element assemblies.

Introduction:

A Green NCV was identified for failure to comply with 10 CFR Part 50, Appendix B, Criterion III, related to the design-control measures used in the extension of the CEA design lifetime.

Description:

During the problem identification and resolution inspection (Inspection Report 50-528/02-05; 50-529/02-05; 50-530/02-05, dated March 20, 2002), the inspectors reviewed the subject LER and associated corrective action documentation available at that time. During this inspection period, inspectors reviewed the significant CRDR root cause investigation report dated July 26, 2002. The failures of the CEA fingers occurred when irradiation induced swelling of the boron carbide pellets inside the fingers generated sufficient strain in the inconel cladding to initiate irradiation assisted stress corrosion cracking (IASCC). IASCC can occur when the cladding material is sensitized by fast neutron flux in combination with the presence of strain while exposed to an aggressive environment. The licensee's CEA design was a relatively new design using reduced diameter boron carbide pellets within a feltmetal sleeve in the lower 12.5 inches of the fingers. The licensee utilized the CEA Lifetime Limit (CEALL) software, which was developed based, in part, on the available hot cell data from examination of nonfeltmetal CEA fingers, to justify continued use of the CEAs beyond the original design lifetime of 10 years described in the UFSAR. The onset of IASCC occurred much sooner than predicted by the licensee's CEALL calculations. The behavior of the boron carbide pellets in conjunction with the feltmetal sleeve at high fluence exposures was not thoroughly understood during the design of the fingers and not verified by experimental methods at high fluence exposure. Because these models and limits were not benchmarked with experimental data from feltmetal tipped CEA fingers at high fluence exposures, the CEALL code overestimated the life of the fingers.

Analysis:

The licensee failed to implement adequate design control measures to recognize that the CEALL code had not been benchmarked with experimental data from feltmetal fingers at high fluence levels. The finding was considered more than minor in that the issue was associated with the reactivity control attribute of the mitigation systems cornerstone and resulted in plant operations with degraded CEAs. The licensee's failure to implement design-control measures to ensure that adequate testing had been performed to validate the CEALL tool was determined to have very low safety significance (Green) using the significance determination process of Inspection Manual Chapter 0609. The finding was determined to only affect the mitigation systems cornerstone and was a deficiency that did not result in the actual loss of the safety function.

Enforcement:

10 CFR Part 50, Appendix B, Criterion III, Design Control, requires, 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. Furthermore, it states that, when a test program is used to verify adequacy of a specific design feature, it shall include suitable qualification testing of a prototype unit under the most adverse design conditions. Contrary to the above, during the period of March 1998 to November 1999, the licensee used inadequate design control measures when implementing a design change to extend CEA lifetime beyond the UFSAR design lifetime of 10 years. Specifically, the licensee failed to identify that the CEALL code had not been benchmarked with experimental data from feltmetal fingers at high fluence levels which resulted in an overestimation of CEA lifetime.

Because this violation was of very low safety significance and the licensee entered this finding into the corrective action program as CRDR 2377444, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-528, 50-529, 50-530/02-06-02).

The apparent failure mode of the CEA fingers identified through the root cause investigation was IASCC. This failure mode occurred earlier than predicted due to inadequate CEA modeling in that CEALL did not accurately reflect the behavior of the feltmetal tipped fingers resulting in nonconservative lifetime estimates. The licensee has planned corrective actions to prevent recurrence of IASCC.

4OA5 Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles (TI 2515/145)

.1 Bulletin 2001-01 Response and Inspection Overview

a. Inspection Scope

On October 2-11, 2002, the inspectors performed NRC Inspection Manual Temporary Instruction 2515/145 for Unit 1 during Refueling Outage 1R10. Inspectors reviewed the licensee's inspection plan in response to NRC Bulletin 2001-01. The inspectors noted that Palo Verde Unit 1 was considered a moderate-susceptible plant (Bin 3) according to the bulletin. The inspectors noted that Bulletin 2001-01 recommended a 100 percent effective visual examination of the surface of the reactor vessel head and the annulus area around each penetration nozzle. However, the licensee expressed excessive difficulty in visually inspecting the area above the reactor vessel head, under the permanent insulation package. Therefore, the licensee committed to a 100 percent under head volumetric examination of each control rod drive mechanism nozzle, and a qualified visual examination of the reactor vessel head vent. The licensee's methodology employed both ultrasonic and eddy current examination of the under head sections of each nozzle. Their plan also considered that no significant amounts of boric acid had leaked onto the head or insulation in the past, and that a visual inspection of 24 periphery nozzles at the beginning of this outage showed no significant amounts of boric acid trails or staining. Through discussions with the licensee and conferences with NRR, the inspectors assessed the validity of this methodology to meet the intent of NRC Bulletin 2001-01.

b. Findings

No findings of significance were identified.

.2 Volumetric Examinations

a. Inspection Scope

The inspectors verified that the licensee's volumetric inspection plan and critical performance objectives were incorporated into site procedures. They also interviewed plant inspection personnel, and contractors performing the inspections, to determine their understanding of NRC Bulletin 2001-01 and the specific inspection plan. The inspectors reviewed Westinghouse Field Service Procedures MRS-SSP-1343, Revision 0, WDI-UT-010, Revision 3, and WDI-UT-013, Revision 1, which governed the volumetric testing. NRR personnel, in conjunction with the inspectors, reviewed the qualification of these methods and their ability to determine flaws in j-groove welds and base metals associated with primary water stress corrosion cracking. The inspectors reviewed licensee and contractor certifications and conducted interviews with plant engineers and Westinghouse contractors to determine their training, background, and expertise in conducting and analyzing these examinations. The inspectors also observed equipment operation during data gathering and the data analysis for a sample of head penetration nozzles.

b. Findings

No findings of significance were identified.

.3 Qualified Visual Examinations

a. Inspection Scope

The inspectors observed licensee and contractor personnel perform the visual inspection of the reactor vessel head periphery nozzles. The inspectors discussed the scope of the inspection with licensee and contractor personnel. They also discussed the qualification and experience of the examiners. The inspectors observed the setup and testing of the remote video equipment used for the examination. The inspectors observed the visual examination to verify that a clear 360 degree observation could be made and that no evidence of cracking or boric acid crystals were present.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

Exit Meeting Summary

The resident inspectors presented inspection results to Mr. G. Overbeck, Senior Vice President - Nuclear, and other members of licensee management on January 3, 2003.

The Division of Reactor Safety inspectors presented the inspection results to Mr. W. Ide and other members of licensee management on October 11, 2002. Licensee management acknowledged the inspection findings.

The inspectors presented the emergency preparedness inspection results to Mr. D. Crozier, Program Leader; Emergency Planning, and other members of licensee management during a telephonic exit interview conducted on October 30, 2002. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified by the licensee.

4OA7 Licensee Identified Violations

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

.1 Technical Specifications 5.7.1 and 5.7.2. require high radiation areas, as defined in 10 CFR 20.1003, be barricaded and conspicuously posted. However, on April 14, 2001, and August 7, 2001, the licensee identified examples of high radiation areas that were not barricaded and conspicuously posted, as described in Corrective Action Documents 2379904 and 2412498. The apparent cause of each example was different, therefore, the corrective action for the first example may not have reasonably been expected to prevent the second example. The findings were only of very low significance because neither example involved an over-exposure or possessed a substantial potential for over-exposure.

.2 Technical Specification 5.7.1.b requires individuals entering a high radiation area be provided a radiation monitoring device that continuously integrates the radiation dose rate in the area and alarms when a preset value is received. However, on March 25 and 30, 2002, individuals entered high radiation areas without radiation monitoring devices that continuously integrate radiation dose, as described in the Corrective Action Documents 2497036 and 2500934. The findings were only of very low significance because neither example involved an over-exposure or possessed a substantial potential for over-exposure.

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Banks, Communications Representative, Owner Services
S. Bauer, Section Leader, Regulatory Affairs
J. Bayless, Engineer, Inservice Inspection
P. Borchert, Unit Department Leader, Operations
R. Browning, Engineer, Inservice Inspection
R. Buzard, Senior Consultant, Nuclear Regulatory Affairs
P. Crawley, Director, Nuclear Fuel Management
D. Crozier, Program Leader, Emergency Planning
M. Fladager, Department Leader, Radiation Protection
J. Gaffney, Director, Radiation Protection
F. Gowers, Site Representative, El Paso Electric
T. Gray, Department Leader, Radiation Protection
D. Hansen, Level III Nondestructive Examiner, Steam Generator Projects Group
D. Hautala, Senior Engineer, Regulatory Affairs
R. Henry, Site Representative, Salt River Project
A. Huttie, Department Leader, Emergency Services Division
W. Ide, Vice President, Nuclear Production
L. Johnson, Department Leader, Chemistry
P. Kirker, Department Leader, Operations
A. Krainik, Director, Emergency Services
S. Lantz, Section Leader, Radiation Protection
D. Leech, Department Leader, Nuclear Assurance
D. Marks, Section Leader, Nuclear Regulatory Affairs
D. Mauldin, Vice President, Engineering and Support
M. Melton, Engineering Section Leader, Inservice Inspection
G. Overbeck, Senior Vice President - Nuclear
M. Powell, Department Leader, Maintenance Engineering
J. Pratt, Engineering & Operations Member, Salt River Project
T. Radtke, Director, Maintenance
M. Renfroe, Section Leader, Design Engineering
J. Reynoso, Steam Generator Engineer, Steam Generator Projects Group
J. A. Scott, Director, Chemistry
J. J. Scott, Department Leader, Nuclear Assurance
D. Smith, Director, Operations
M. Sontag, Department Leader, Nuclear Assurance
D. Straka, Senior Consultant, Compliance
R. Stroud, Senior Consultant, Regulatory Affairs
J. Taylor, Engineering & Operations Member, Salt River Project
T. Weber, Section Leader, Regulatory Affairs
M. Winsor, Director, Nuclear Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-530/02-06-01	NCV	Inadequate Procedure Used During Loss of Letdown Event (Section 1R14)
50-528/02-06-02; 50-529/02-06-02; 50-530/02-06-02	NCV	Inadequate Design Control Measures Used to Extend CEA Design Lifetime (Section 4OA3.4)

Closed

50-530/02-06-01	NCV	Inadequate Procedure Used During Loss of Letdown Event (Section 1R14)
50-528/02-06-02; 50-529/02-06-02; 50-530/02-06-02	NCV	Inadequate Design Control Measures Used to Extend CEA Design Lifetime (Section 4OA3.4)
50-528/02-005-00	LER	Inadequate Surveillance Test for Time Response Testing of HI Log Power Trip Function (Section 4OA3.1)
50-530/2002-001-00	LER	TS Violation Due To Incorrect Constant Entered In COLSS (Section 4OA3.2)
50-529/2002-002-00	LER	Post-test Constants Entered Into CPC System (Section 4OA3.3)
50-528/2001-003-00; 50-529/2001-003-00; 50-530/2001-003-00	LER	Technical Specification Required Shutdown Due to Degraded Control Element Assemblies (Section 4OA3.4)

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:

Work Orders

2538517	2461367	2456688	2470872
2540558	2454339	2569893	2553633
2456756	2324118	2417233	

Condition Report/Disposition Requests

2383990	2499573	2516020	2448048
2453504	2505573	2530281	2559098
2458565	2507107	2553223	2564721
2458568	2510151	2557032	

Procedures

Number	Title	Revision
73DP-0EE16	Qualification and Certification of NDE Personnel	4
73TI-0EE01	Ultrasonic Instrument Calibration	3
73-TI-9RC01	Steam Generator Eddy Current Examinations	22
73TI-9ZZ07	Liquid Penetrant Examination	9
73TI-9ZZ 80	ASME Section XI Appendix VIII Ultrasonic Examination of Austenitic Piping	3
81DP-9RC01	PVNGS Steam Generator Degradation Management Program	2
40ST-9EC03	Essential Chilled Water and Ventilation Systems Inoperable Action Surveillance	11
74DP-9CY04	System Chemistry Specifications	19
41OP-1EC01	Essential Chilled Water Train A	37
41ST-1EC01	Essential Chilled Water Valve Verification	16
MRS-SSP-1343	Reactor Vessel Head Penetration Inspection for Palo Verde Unit 1	0
WDI-UT-010	IntraSpect Ultrasonic Procedure for Inspection of Reactor Vessel Head Penetrations, Time of Flight Ultrasonic, Longitudinal Wave and Shear Wave	3
WDI-UT-013	CRDM/ICI UT Analysis Guidelines	1
WDI-ET-002	IntraSpect Eddy Current Inspection of J-Groove Welds in Vessel Head Penetrations	1
WDI-ET-003	IntraSpect Eddy Current Imaging Procedure for Inspection of Reactor Vessel Head Penetrations	3
WDI-ET-004	IntraSpect Eddy Current Analysis Guidelines for Inspection of Reactor Vessel Head Penetrations	1

<u>Test Reports</u>

Liquid Penetrant Examinations

PT-02-109
PT-02-110

Ultrasonic Examinations

UT-02-170
UT-02-171
UT-02-172
UT-02-173

<u>Miscellaneous</u>

Palo Verde Steam Generator Eddy Current Program Analysts Guidelines Training Manual, Revision 20

Reactor Oversight Program MSPI Pilot Bases Document

P & I Diagrams, Safety Injection and SDC System/Essential Cooling Water System/Essential Spray Pond System

Palo Verde Generating Station Design Basis Manual - EW System, Revision 15, SP System, Revision 12

Maintenance Rule Unavailability Detail Report with Mode Changes

Maintenance Rule Demands Report

NRC Regulatory Issue Summary 2002-14

NRC Inspection Manual Temporary Instruction 2515/149

LIST OF ACRONYMS USED

CEA	control element assembly
CEALL	control element assembly lifetime limit
COLSS	core operating limits supervisory system
CPC	core protection calculator
CRDR	condition report/disposition request
DNBR	departure from nucleate boiling ratio
GTG	gas turbine generator
IASCC	irradiation assisted stress corrosion cracking
LER	licensee event report
LHR	linear heat rate
LOCA	loss of coolant accident

MSPI	Mitigating Systems Performance Index
NCV	noncited violation
NDE	nondestructive examination
POL	power operating limit
RCS	reactor coolant system
SDC	shutdown cooling
UFSAR	Updated Final Safety Analysis Report
WO	work orders