APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-528/94-22
50-529/94-22
50-530/94-22

Licenses: NPF-41
NPF-51
NPF-74

Licensee: Arizona Public Service Company
P.O. Box 53999
Phoenix, Arizona

Facility Name: Palo Verde Nuclear Generating Station, Units 1, 2, and 3

Inspection At: Maricopa County, Arizona

Inspection Conducted: June 12 through July 23, 1994

Inspectors: K. Johnston, Senior Resident Inspector
H. Freeman, Resident Inspector
J. Kramer, Resident Inspector
A. MacDougall, Resident Inspector
D. Acker, Project Inspector

Approved: H. Wong, Chief, Reactor Project Branch F — 8/30/94 Date

Inspection Summary

Areas Inspected: Routine, announced inspection of plant status, onsite response to events, operational safety verification, and maintenance and surveillance observations.

Results (Units 1, 2, and 3):

- Plant Operations

In June, Unit 1 operators identified that a routine channel calibration check of core protection calculator channel "D" could not be performed because a reactor coolant system temperature input was fluctuating greater than the channel calibration check acceptance criteria. However, the magnitude of channel fluctuations had changed little since early 1993 and had not been properly addressed by operations (Section 2.1).

The NRC inspectors noted unauthorized and inconsistent operators aids in the control rooms (Section 3.1).

The NRC inspectors noted unauthorized and inconsistent operator aids in the control rooms (Section 3.1).

An alert and questioning auxiliary operator identified a leak in the Unit 1 spray pond piping during a routine tour (Section 4.1).

- Maintenance

The planning and performance of an emergent repair to a leak in the spray pond piping was thorough and well implemented. Engineering evaluation of the failure was thorough (Section 4.1).

- Engineering

While engineering's evaluation of the cause and safety impact of fluctuations in hot leg temperature was thorough, they missed an opportunity to identify that the daily channel calibration check of the CPC could not be performed (Section 2.1).

Engineering appears to have made progress in improving the performance and reliability of the feedwater and steam bypass control systems. Additionally, they appear to be pursuing further modifications to further improve performance (Section 6).

Engineering has completed a review of a cable installation data base which had previously not been well controlled and was not reliable. The licensee has updated the data base and has improved controls to assure future data base reliability (Section 7).

- Plant Support

Two portable chemistry monitoring instruments were found by the inspector to have been installed for extended periods. The licensee responded quickly to remove the monitors and evaluate their procedures for the use of temporary monitoring equipment (Section 5.1).

The licensee has used temporary shielding in areas of high radiation for extended periods without aggressively pursuing permanent solutions (Section 5.2).

Material condition appeared to have deteriorated in some areas. In Unit 3, an excessive amount of debris from maintenance and cleaning activities was noted. Additionally, a program to monitor and minimize boric acid leaks in valve packings appeared not to have been fully implemented (Section 3.4). Also in Unit 3, an auxiliary feedwater pump junction box was not fully secured (Section 3.3).

- Management Overview

During the inspection, several findings were identified that highlighted an apparent lack of plant management in the field. For example, a month after a refueling outage the inspector noted material condition weaknesses in Unit 3 which could be attributed to outage work. It was also noted that, during this period, licensee management focused a substantial amount of time on the reorganization selection process.

Summary of Inspection Findings:

- One violation of NRC requirements was identified (Section 2.1).

Attachment:

Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 operated at 86 percent power from June 12-30 when the licensee raised reactor power to 98 percent in response to high electric demand on the southwestern grid. Reactor power was limited to 98 percent for the rest of the inspection period due to two inoperable main steam safety valves. On July 6, the licensee implemented a Technical Specification (TS) change which allowed operation at a 10°F lower RCS temperature.

1.2 Unit 2

Unit 2 began the inspection period in Mode 1 at 86 percent power. On June 30, 1994, the unit increased power to 100 percent due to high electric demand on the southwestern grid. On July 8, the licensee decreased power to 88 percent, after the electric demand had decreased, and remained there through the end of the inspection period. Power was returned to 88 percent vice 86 percent based on a revised calculation of steam generator tube dryout. Also on July 8, a management meeting was held in the Region IV office in Arlington, Texas, to discuss the May 28, 1994, reactor trip.

1.3 Unit 3

Unit 3 began the inspection period in Mode 5, completing the fourth refueling outage. The unit commenced a normal reactor startup and entered Mode 2 operations on June 18. On June 24, the unit completed testing and raised power to 100 percent. The unit remained at essentially 100 percent through the end of the inspection period.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Unit 1 RCS Hot Leg Temperature Fluctuations

On June 19, 1994, a reactor operator noted that the digital readout of calculated thermal power on CPC Channel D was oscillating by more than 6 percent power. The shift supervisor concluded that the TS surveillance requirement to calibrate the calculated thermal power to within ± 2 percent of the secondary calorimetric power could not be performed because the magnitude of the oscillations was greater than ± 2 percent (4 percent absolute). As a result, the shift supervisor declared CPC Channel D inoperable and placed the affected reactor protection functions in bypass.

The licensee determined that the large fluctuation in calculated thermal power was caused by a known fluctuation in the CPC Channel D Loop 2 hot leg temperature (T_{hc}) instrument used to calculate thermal power. The fluctuation appears to be actual loop temperature fluctuations and not an instrument

issue. The licensee developed a temporary modification (TMOD) to upgrade a nonsafety-related T_{hot} resistance temperature detector (RTD) that displayed less fluctuations and to use it as the input to the CPC. On July 2, the licensee installed the TMOD and returned CPC Channel D to service.

The inspector reviewed the 10 CFR 50.59 evaluation for installation of the TMOD, the TS limiting conditions for operation (LCO) and surveillance test requirements, the engineering evaluation of the cause of the Channel D hot leg temperature fluctuations, and the plant review board's response to an engineering presentation of the hot leg temperature fluctuations. The inspector conducted a field verification of the TMOD installation. The inspector concluded that:

- Engineering had identified oscillations of up to 5°F in the Unit 1 Channel D hot leg temperature input to the CPC on February 18, 1993. They identified that the temperature fluctuations were due to hot leg temperature stratification.
- Engineering subsequently concluded that the fluctuations did not create a situation adverse to safety, and the CPC was able to perform its design function. Their evaluation of the cause and safety impact of the fluctuations in hot leg temperature was thorough.
- Operators were performing routine channel calibration checks of CPC Channel D and did not conclude that the check was out of calibration due to the magnitude of the temperature fluctuations until June 1994, even though the magnitude of the fluctuations had changed little since early 1993. As a result, the TS requirement to perform a channel calibration was not performed.
- Licensee management missed opportunities to identify the impact of the temperature fluctuations on the channel calibration check.
- The development and implementation of the TMOD was appropriate.

2.1.1 Engineering Evaluation

On February 18, 1993, the nuclear fuel engineering analysis group first identified that the Unit 1 Loop 2 hot leg Channel D temperature instrument exhibited oscillations of up to 5°F. Engineering noted that the magnitude of the oscillations were substantially larger than any similar instrument on site. The licensee initiated an engineering evaluation (EER 93-RC-017) to determine the cause of the fluctuation.

Engineering gathered data from the instrument and the RTD. The data was analyzed for any sharp jumps or discontinuities, which could indicate component failure, but none were found. The plotted data appeared to have an exponential shape, which was the expected shape for an RTD responding to an actual temperature fluctuation. Next, the licensee analyzed the data using

fast Fourier transform analysis to determine if there were any periodic events, such as electrical noise, which could be the source of the fluctuations. The analysis revealed that the fluctuations appeared to be random and were not the result of a periodic driving event. Engineering concluded in the evaluation that the observed fluctuations in temperature appeared to be the result of the RTD responding to actual changes in the RCS temperature. The licensee had previously replaced another RTD that had exhibited similar fluctuations. The new RTD continued to exhibit the same fluctuations.

In January 1994, the licensee completed a study and concluded that the RTD fluctuations were due to RCS hot leg stratification effects. The study included a review of the impact of the temperature variation on the CPC. The licensee concluded that the only effect of the fluctuation on the safety-related functions for the CPC calculated thermal power was for protection against a 12-finger control element assembly (CEA) drop event. The licensee concluded that for a 12-finger CEA dropped in the center of the core, the neutron detectors may not detect a flux tilt or power shift; however, because a 26 percent penalty factor would be automatically inserted for any 12-finger CEA drop, the reactor would trip and the core would be protected. The inspector reviewed the study and agreed with the conclusions.

Engineering noted to the inspector that the vendor, Combustion Engineering (CE), had conducted a study of temperature stratification effects on CE reactors which included data from Unit 1. In a letter to the licensee dated February 22, 1991, CE explained that the temperature stratification in CE reactors usually appears to have a static component, the upper half of the hot leg pipe is hotter than the lower half; phase rotation, the hottest and coldest point in the pipe is not necessarily at the top and bottom of the pipe, but rotated by an angle; and a dynamic component, where a semi-stable vortex shifts from one portion of the pipe to another semi-stable position. CE had identified these conditions in other CE plants. At the time, however, Unit 1 did not exhibit the dynamic component. Finally, CE explained that the characteristics of the stratification depended on numerous factors including fuel loading, rod position, and core age and that the characteristics would change over time.

The inspector concluded that the licensee conducted a thorough review of the cause and effects of the hot leg temperature stratification issue. The inspector agreed with the licensee's conclusion that the CPC had enough margin to account for the fluctuations and that the core was not in an unreviewed condition. The inspector noted that this review had been concluded in early 1994. As discussed below, the inspector was concerned that the effects of the temperature fluctuations on the routine performance of CPC channel calibration check were not fully evaluated.

2.1.2 TS Verification

Facility TS require that a channel calibration check be performed every 24 hours to verify that the linear power level, the CPC thermal power, and the

CPC nuclear power signals are within ±2 percent of the calorimetric power. This verification is conducted as part of the "Routine Surveillance Daily Midnight Logs," Procedure 40ST-9ZZ16. The procedure directs the operators to record CPC total thermal power, CPC nuclear power, and secondary calorimetric power. The procedure required that the CPC channel be calibrated if either thermal power or nuclear power was more than 2 percent above or below the actual (secondary calorimetric) reading.

On June 19, 1994, operators noted during the channel calibration check that CPC Channel D thermal power was fluctuating by more than 6 percent. Reactor engineering was contacted when CPC Channel D was declared inoperable and determined that known fluctuations in the Channel D T_{hot} instrument were causing the fluctuations in CPC thermal power.

The inspector determined in a review of engineering data and operator interviews that there had not been significant change in the fluctuations of CPC Channel D from February 1993 to June 1994. Since 1 degree of change of temperature across the reactor core represents a change of about 1.5 percent power, the fluctuations of 4 to 5 degrees, measured in February 1993, would have caused the calculated thermal power to consistently deviate greater than the ±2 percent TS limit. The inspector concluded that, since February 1993, the licensee could not have acceptably performed the required channel calibration. This is a violation of TS 4.3.1.1 (Notice of Violation 528/9422-01).

The inspector recognized that the fluctuations in thermal power did not create a situation adverse to safety (See Section 2.1.1) and that CPC Channel D was able to perform its design function. However, this violation was being cited because operators had not recognized for over a year that the calibration check could not be adequately performed. Additionally, plant management missed opportunities to identify the effects of the temperature fluctuations on the channel calibration checks (Section 2.1.3).

The inspector questioned why operators had not recognized earlier that the channel calibration check could not be adequately performed on CPC Channel D. The inspector found from discussions with operators that they typically took an informal mean value of the fluctuating instrument reading. The inspector found that the licensee did not have formal guidance for operators to evaluate oscillating or fluctuating instrument readings. The inspector questioned whether there were other routine measurements or readings taken from fluctuating instruments which required further evaluation. The inspector discussed these concerns with licensee management who indicated that the reading of fluctuating instruments will be evaluated. The inspector will review this issue further in conjunction with the licensee's response to the violation.

2.1.3 Plant Review Board (PRB) Review

The inspector noted that in April 1994 representatives from plant engineering made a presentation to the PRB concerning the Unit 1 T_{hot} fluctuations. The

inspector reviewed the PRB minutes and noted that engineering had questioned how the TS verification was performed. In the presentation, engineering stated that "the temperature reading variability has added some difficulty for the CPC thermal power calibration in that it was difficult to decide what temperature value (an average, the lowest, the highest?) to select for use in the thermal power calculation." Engineering also stated that "there was not any definite operations guidance on how to select the appropriate reading."

Based on the engineering presentation, the PRB board concluded that there was not an unreviewed safety question or safety concern with the T_{hot} fluctuations. However, the licensee did not conduct any followup to investigate the questions posed by engineering concerning the thermal power calibration. The inspector concluded that licensee management had missed an opportunity to identify the problem in April 1994. Additionally, the inspector concluded that the licensee had missed a similar opportunity to identify the effects of the temperature fluctuations when they were first identified in February 1993.

2.1.4 TMOD Development and Implementation

The licensee developed a TMOD to swap an installed nonsafety-related T_{hot} RTD, used for input to the core operating limit supervisory system, for the safety-related RTD used as an input to CPC Channel D. The inspector reviewed the 10 CFR 50.59 evaluation for the TMOD and agreed with the licensee's conclusion that the TMOD did not create an unreviewed safety question and was acceptable for a short period.

The inspector conducted a walkdown of the affected electrical penetrations and cable raceways. The inspector noted that one of the covers had a missing and stripped fastener. The inspector was concerned that the electrical penetration cover was not water tight due to the missing fastener. The licensee initiated a work request to correctly install the fastener. The inspector concluded that the licensee's corrective actions were appropriate.

2.1.5 Licensee Actions

Based on the inspector's concerns, the licensee formed a team to evaluate the effect of the T_{hot} fluctuations on performance of the CPC calibrations. The licensee also was issuing a licensee event report describing the problem with CPC Channel D and concluded that CPC Channel D was inoperable for the last 2 operating cycles. The licensee event report will be reviewed in a future inspection.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Units 1, 2, and 3, Use of Operator Aids and Control Room Labeling

On June 28, 1994, the inspector observed red grease pen marks on the control room (CR) operating switches for CR heating, ventilation and air conditioning (HVAC) in Unit 2. The inspector was informed that the marks were placed on the switches to aid the operators in the identification of valves

required to be open during power operations. Further inspection revealed the same marks present in Unit 1. The inspector noted that the marks were not controlled under the licensee's operator aid program and notified operations management of the unauthorized markings on the CR boards. The licensee removed the markings.

The inspector checked the consistency of the CR labels, placards, and operator aids. The inspector noted several minor discrepancies and brought them to the attention of operations management. These aids included a plexiglass cover over a Unit 2 reactor coolant pump hand switch, apparently used to prevent operators from inadvertently turning the pump off, which was not used in either Units 1 or 3. Additionally, small placards in Unit 3 cautioned that synchronization key switches should not be inserted into more than one selector switch at a time. Similar placards were not used in Units 1 and 2.

The inspector noted that the licensee had a detailed procedure governing the use of operator aids. The procedure had been developed in response to weaknesses identified in 1989. The inspector expressed concern that the program was not being fully implemented. In response to the inspector's concerns, the licensee assigned the Unit 1 operations department leader to review the use of operator aids and the process of labeling control room equipment.

On July 25, the inspector observed that the CR HVAC switch markings were once again present on the switches in Unit 1. The inspector notified operations management of the unauthorized markings on the CR boards, and once again the licensee removed the markings. The licensee initiated a night order to inform operators of management's expectations for marking and labeling plant equipment. At the exit meeting, the inspector expressed concern that management had not fully communicated the expectation that the markings not be used after the first incident, nor had they identified the markings themselves.

3.2 Unit 1 - Walkdown of Engineered Safety Features (ESF) Equipment Room Ventilation System

The inspector reviewed the Updated Final Safety Analysis Report, conducted a field walkdown, and reviewed the design heat loading calculation for the ESF equipment room ventilation system.

The ESF equipment room ventilation system provides room cooling for four safety-related 125-Vdc and 120-Vac distribution systems. Each system is located in a separate room that is cooled by the normal control building ventilation system. The ESF equipment room ventilation system provides cooling to the equipment rooms on a loss of normal ventilation and on a loss of offsite power or safety actuation signal.

The inspector concluded that the ESF equipment room ventilation system would provide sufficient cooling flow to ensure that the safety-related 120-Vac and 125-Vdc electrical distribution systems remained operable. The inspector

noted a minor material deficiency involving a missing nut on a ventilation damper support plate that was promptly corrected.

The inspector noted that the alarm response procedure for a high temperature alarm in the ESF equipment room did not indicate at what point TS LCOs should be entered. The licensee stated that the surveillance test procedure for inoperable essential chilled water and ventilation systems directed the ESF equipment room to be declared inoperable if both the normal and essential ventilation systems were inoperable. This would put the plant in a 72-hour TS shutdown LCO. The licensee agreed that the alarm response procedure should reference the surveillance test procedure and initiated an update to the alarm response procedure. The inspector concluded that the licensee actions were appropriate.

3.3 <u>Auxiliary Feedwater Pump Junction Box - Unit 3</u>

On July 5, 1994, the inspector noted that the cover to a junction box on the Unit 3, turbine-driven auxiliary feedwater pump was not fully secured. The inspector contacted the shift supervisor and raised concerns about the potential impact of a high steam environment on the internal components.

When informed by the inspector of the junction box cover, the supervisor immediately sent an electrician to open and inspect the components in the junction box. The electrician inspected the junction box and did not find any degraded components. Following the inspection, the electrician fully secured the junction box cover.

The licensee initiated an operability determination on the effect that the condition had on the pump's operability. The junction box, which housed power and control cables to the turbine's trip and throttle valve motor operator (AFA-HV-54), was approximately 14"x16"x6" and contained a hinged cover. The junction box had four mechanisms to secure the cover but only one had been engaged. The licensee conducted a seismic review and concluded that one mechanism was adequate to keep the cover in position during a seismic event. Additionally, the licensee concluded that the junction box was not in a harsh environment and that the humidity during pump operation would not have caused electrical problems to the trip and throttle valve motor operator. The inspector agreed with the licensee's conclusions. Finally, the licensee initiated an investigation on how the junction box cover became not fully secured.

The inspector concluded that the licensee took prompt corrective actions and that the impact of the condition did not affect the operability of the auxiliary feedwater pump.

3.4 <u>Material Conditions - Unit 3</u>

On July 14, 1994, during a routine tour of the 77 foot level of the east piping penetration room in Unit 3, the inspector noted that the material conditions had degraded over the past few months. For example, the inspector

found several valves which had boric acid accumulation in the yoke area. The inspector noted a safety injection vent valve with a continuous stream discharging into a drain through a tygon tube and contacted the operations crew to secure the leak. The inspector also noted a shutdown cooling system valve that had a large amount of dried boric acid crystals on the valve body and on the floor. Finally, the inspector noted debris (a cut mechanical lock, a bag of parts, a roll of electrical tape, and other residual trash) from the recent refueling outage that had not been removed from the area. The inspector concluded that the material condition and housekeeping in the space did not represent safety hazards, but were indicative of an overall declining trend.

The inspector reviewed the licensee's program for maintaining valve material conditions and minimizing valve packing leaks. The inspector noted that the licensee has a zone inspection program where each operations crew was responsible for a specific area. Each crew was expected to perform an area inspection once each work cycle (every 6 weeks) and was to submit work requests when needed. The inspector reviewed the previous inspection for the area and noted that it had been completed on July 13 but had not identified the leaking vent valve or the boric acid on the shutdown cooling system valve. The inspector also noted that the program was more effectively used by some crews than others. For example, one previous inspection of three zones conducted on February 8 (several hundred valves) did not identify any discrepancies where other area inspections typically identified 20 to 30 discrepancies.

The inspector discussed the zone inspection program and general plant conditions with the licensee. The inspector noted that the program was not formally controlled and was not consistently implemented. Licensee management concurred that the program has not been fully effective. They anticipated that the system responsibilities assigned to maintenance crews in the re-engineering process would promote material condition improvements.

The inspector found in discussion with Unit 3 management that managers had not toured the area recently. This was of concern since Unit 3 had recently restarted from a refueling outage. Additionally, the inspector noted that the licensee's response to the previous Systematic Assessment of Licensee Performance committed to having management in the field on a frequent basis to identify problems. The inspector concluded that the licensee's program for material control and housekeeping required more management attention.

3.5 Unit 2 Crane Breaker Closed and Caution Tagged "Open"

On July 1, 1994, the inspector noted the breaker for an auxiliary building crane was closed with a caution tag on the breaker stating "contact safety department before operating crane/energizing breaker.". The inspector contacted the safety department and determined that the crane was not being used and that the breaker should have been in the open position. Operations was informed, and the breaker was opened.

The licensee had placed the caution tag on the crane breaker as an interim corrective action until the crane's pendant could be modified to comply with Occupational Safety and Health Administration (OSHA) standards to have an emergency stop push button or equivalent. As a result of the inspector's finding, the licensee placed an additional caution tag on the control pendant on all similar type cranes in the plant (11 total) to alert personnel of the potential hazard in operating this type of crane and replaced the caution tag on the breaker with a danger tag. The licensee planned to evaluate the 11 similar cranes to determine which were used frequently and warranted the pendant modification. They planned to remove power from cranes that were not frequently used.

The inspector noted the quick and thorough response of the licensee after the inspector identified and informed the licensee of the problem. The inspector concluded that the licensee actions were adequate.

4 MAINTENANCE OBSERVATIONS (62703)

During the inspection period, the inspector observed and reviewed the selected maintenance activities listed below to verify compliance with regulatory requirements and licensee procedures, required quality control department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, appropriate radiation worker practices, calibrated test instruments, and proper postmaintenance testing. Specifically, the inspector witnessed portions of the following maintenance activities:

4.1 Unit 1 - Spray Pond Piping Leak Due to Coating Degradation

On July 10, 1994, an auxiliary operator (AO) noted water under a portion of the Train A spray pond piping during a routine tour. The AO inspected the piping and identified a small pin hole leak in the piping. The Train A spray pond system was declared inoperable. The spray pond system is the ultimate heat sink for the essential cooling water system which provides cooling water to the essential chilled water system, the shutdown heat exchangers, and the emergency diesel generators. As a result, several 72-hour TS LCO action statements were entered.

The inspector reviewed the work order to repair the leak, observed the hydrostatic test of the repair, and discussed the leak with the licensee's engineering staff. The inspector concluded that the licensee's initial actions to solve the problem were good. Specifically, the AO was alert to a deficient condition, the planning and conduct of the maintenance was good, and the initial engineering evaluation was thorough. The inspector also noted that the licensee was evaluating the scope of the overall underground piping inspection program based on this failure.

4.1.1 Corrective Actions

The licensee drained the system, removed and installed a spool piece in the piping, and performed an inside/outside weld repair of the defect. On July 11, the licensee reassembled the pipe and satisfactorily performed a hydrostatic test of the affected portions of the spray pond system. The licensee determined that the piping failure was initiated by a defect in the piping coating. The licensee conducted a visual inspection of the coating on the inside of the accessible portions of the disassembled spray pond piping and did not identify any other defects. The licensee subsequently declared the spray pond system operable and exited the TS LCO action statements.

The inspector noted that the licensee had conducted visual inspections of selected portions of the spray pond piping during the previous refueling outages in each unit. About 450 linear feet of the underground portions of the spray pond supply and return lines and a small portion of piping to the emergency diesel generators were inspected. The inspector noted that the area of the defect was not included in the inspection because the piping was not underground. Representatives from the Electric Power Research Institute performed the inspections and concluded that, in general, the piping was in good condition.and that no immediate corrective actions were needed. The inspector reviewed the reports and noted there was one area in each unit where there appeared to be an actual break in the coating that could lead to accelerated corrosion.

The inspector learned that the licensee had previously evaluated the defects and determined that, based on the known corrosion rates and the limited number of defects, the repairs could be deferred to the next refueling outage. The licensee planned to perform additional visual inspections during the upcoming refueling outages to determine the change in the affected areas and to conduct any required repairs. The inspector concluded that the licensee's basis to defer the repairs was reasonable and that the existing spray pond piping inspection program was adequate.

4.2 Unit 2 - CEA Slip During Testing

On June 18, 1994, during the performance of CEA Operability Checks (Surveillance·Procedure 42ST-2SF01), CEA 60 slipped about 2 inches each time it was given a withdrawal command and then would withdraw as designed.

Operations personnel consulted with engineering and the operations manager and then placed CEA 60 at the upper electrical limit (UEL) upon completion of the surveillance to provid additional positive indication that the CEA was fully withdrawn and had not slipped. The other CEAs remained at the program level of UEL-2 (two steps below the UEL). The licensee initiated a condition report/disposition request to evaluate the problem.

The inspector questioned reactor engineering about the placement of CEA 60. Reactor engineering stated that the CEA was within the TS limit for deviation from other CEAs and that the CEA position did not violate the core data book.

In addition, reactor engineering stated that having one CEA 1.5 inch (two steps) further withdrawn at the top of the core would not adversely affect core power distribution or guide tube wear. The inspector agreed with the licensee conclusions.

The inspector noted in a conversation with the Unit 2 reactor engineer that he was unaware that CEA 60 had been positioned at the UEL. While there was little safety significance, the inspector was concerned that a week after the CEA had been repositioned, the responsible engineer was not cognizant of the condition. The licensee acknowledged the inspector's comments and indicated that the issue would be further reviewed.

On July 16, the licensee repaired CEA 60. Two defective equipment cards were replaced. The licensee returned CEA 60 to program position. The licensee planned to repair the defective cards in their rework shop. The inspector reviewed the licensee's troubleshooting process for the defective cards and noted no discrepancies.

4.3 Other Maintenance Observations

The inspector observed portions of the following maintenance activities and determined that they were performed acceptably:

- Unit 1 Feedwater Pump Governor Power Supply Repairs
- Unit 2 Control Room Essential Air Handling Unit Cooling Coil and Bellows Inspection Preventative Maintenance
- Monthly Preventative Maintenance on the Security Diesel

5 PLANT SUPPORT (71750)

The inspector performed routine tours of the units to verify that radiological, physical security, and fire protection programs were implemented in accordance with facility policies and regulatory requirements. Included in these tours were verifications of the accessibility to locked high radiation areas, posting of radiation areas, physical security control, and general material conditions.

5.1 Continuous In-Line Chemistry Monitors

During routine plant tours. the inspector identified a condition in Unit 3 where a portable oxygen detector was installed to a condensate storage tank test connection to obtain a continuous on-line reading. The inspector also noted a similar condition in Unit 2 where a portable conductivity meter was installed to a sample point on the auxiliary steam condensate receiver tank outlet valve to provide a continuous on-line reading. The inspector noted that these installations were not controlled as temporary modifications and questioned the licensee concerning plant configuration control.

The licensee initiated a condition report/disposition request to review the control of these particular installations. The licensee determined that these installations were controlled by approved chemistry sampling procedures. However, the inspector was concerned that the intent of the procedures was primarily for short duration or "grab" type samples and not for a condition that may require a long-term continuous monitor. The licensee acknowledged the inspector's concern and agreed to review the secondary sampling instruction procedure to verify if the procedural controls for continuous sampling were adequate.

The inspector concluded that the licensee had valid reasons for installing the monitors, that they were being periodically reviewed by chemistry management, and that they did not impact equipment operability. The inspector also noted that the licensee removed the monitors until the review of the procedure was completed. The inspector concluded that the licensee's corrective actions were prompt and thorough.

5.2 Locked High Radiation Areas - Unit 3

On July 14, 1994, during a routine tour of the Unit 3 auxiliary building, the inspector noted that some of the temporary shielding installed around high radiation sources had been installed for extended periods up to 5 years.

For example, the inspector noted that the licensee had installed temporary shielding and a sign on a section of piping which stated that the radiation levels under the shielding met the conditions of a locked high radiation area. Because the shielding was covered by plastic sheeting, the inspector was unable to view the installation. The inspector noted that the installation had been in place since March 14, 1994. The inspector discussed the use of temporary shielding with the licensee and was informed that temporary shielding was usually held in place by plastic tie wraps or some other nonpermanent means. Although the inspector noted that most temporary shielding was removed after 2 weeks, the inspector also noted 13 installations which had been converted to long-term use, including four that were over a year old.

The inspector discussed with radiation protection management the NRC's guidance on the use of temporary shielding on areas that meet the requirements of a locked high radiation area as discussed in NUREG/CR 5569, "Health Physics Positions Data Base." The NUREG states "other techniques to reduce source term should be used (e.g., chemical decontamination, permanent shielding); however, as long as reasonable progress is made toward the long-term fix (and an effective system to preclude unauthorized removal of temporary shielding exists), the judicious use of temporary shielding could be justified on an interim basis." The inspector noted that the licensee did not appear to be aggressively pursuing the long-term fix. The licensee stated that they would review the use of temporary installations, including shielding and modifications, and attempt to limit their use. The inspector noted that the licensee had conducted an audit a few weeks earlier and had similar concerns

regarding the use of temporary shielding. The inspector will follow up on the licensee's resolution of temporary installations as part of a future routine inspection.

6 FEEDWATER CONTROL SYSTEM (FWCS)/STEAM BYPASS CONTROL SYSTEM (SBCS) (71500)

The inspector reviewed the design and operation of the FWCS and the SBCS and discussed recent maintenance problems concerning these systems with operators and the system engineers. The purpose of the inspection was to determine the scope and effectiveness of the licensee's long-term FWCS and SBCS improvement program.

The inspector noted that the licensee has made significant progress in correcting a majority of problems with the FWCS and SBCS. In 1991, the licensee performed major control system modifications that significantly reduced the number of postreactor trip control system complications. For example, during a 3-year period from 1989 to 1991 the site had 19 reactor trips which resulted in 19 postreactor trip control system complications and nine postreactor trip safety system actuations. After the modifications in 1991, the site has had a total of 13 reactor trips which resulted in 10 postreactor trip control system complications and 4 postreactor trip safety system actuations.

The inspector determined that several minor control system problems still need to be corrected with both the FWCS and SBCS. These problems include current to pneumatic (I/P) transducer and positioner zero drift, low power steam generator level oscillations, and internal binding of the steam bypass control valves (SBCVs). The licensee has identified corrective actions for these problems and has scheduled completion of the actions during the 1995 refueling outages. The inspector also observed a high level of management involvement to assure that these corrective actions are completed as scheduled.

6.1 SBCS Review

The inspector reviewed the licensee's corrective actions for SBCV problems identified during the Unit 2 load rejection on May 14, 1994, and the Unit 2 reactor trip on May 28. SBCVs 1001 and 1004 were reported as "jerky" during the load rejection. In addition, valve 1004 did not fully close during the reactor trip.

The licensee performed diagnostic testing of SBCVs 1001 and 1004 following the load rejection and determined that Valve 1001 operated properly and Valve 1004 had a positioner zero drift which prevented the valve from fully closing. A work order was written to calibrate the positioner of Valve 1004. The work was scheduled for May 20 but was delayed due to a conflict with scheduled work in Unit 1. As a result, the positioner was not recalibrated until after the reactor trip on May 28.

The licensee attributed the jerky response of Valve 1004 to internal clearance problems that had been previously identified. In Unit 2, the licensee has

completed internal clearance modifications on two of the eight SBCVs (1001 and 1003) to improve the smoothness of the valves stroke with steam. These modifications have been completed on all eight control valves in Units 1 and 3. The modifications of the remaining six control valves in Unit 2 were scheduled during the 1995 refueling outage.

6.2 FWCS Review

During the Unit 2 load rejection and reactor trip in May 1994, operators had to close the Steam Generator 1 economizer isolation valve due to excessive feedwater flow, resulting in excessive primary temperature cooldown. After these events, the licensee calibrated the economizer flow control valve and determined that the I/P had drifted 4 percent high. As a result, when the valve received a signal to close, it remained approximately 4 percent open. The licensee recalibrated the I/P and the valve fully closed when required. The I/P drift was a common industry problem and was typically less than 5 percent. The licensee was developing a design modification to insert a negative bias in the control circuit to ensure the valve shuts after a reactor trip and during low power operations. This modification was scheduled for completion in September 1995. The inspector concluded that this improvement should prevent operator intervention after a reactor trip to prevent overfeeding of the steam generator and subsequent overcooling of the primary plant.

6.3 Meeting With the Licensee Regarding Feedwater and SBCS Problems

On July 8, 1994, the licensee met with the NRC at the Region IV office in Arlington, Texas, to discuss the May 28 reactor trip. During this meeting, the licensee discussed the history of problems with the steam generator flow control system and the steam bypass control system and their plans for system improvements discussed above.

7 DESIGN CHANGES AND MODIFICATIONS (37551)

The licensee used a computer based system called the EE580 system, to maintain a data base for cable installations. As documented in Inspection Report 50-528/89-12; 50-529/89-12; 50-530/89-12, previous problems with the EE580 system had been found. The cover letter of Inspection Report 50-528/89-12; 50-529/89-12; 50-530/89-12 requested that the licensee provide an action plan and commitments to review and correct deficiencies with the EE580 system.

Under the EE580 process, installation cards were issued for design changes and the EE580 data base was marked with a "C" to alert personnel that a change had been issued for the installation covered by the card. When the installation was complete, the field verified card was returned, verified to match the design, and the "C" removed from the EE580 data base. However, in 1989 the licensee determined that many more cards had been issued than had been returned with field verification so that over 100,000 items in the EE580 data base were marked with a "C," making the design change process difficult and potentially affecting the accuracy of the data base.

The licensee provided their corrective actions for the EE580 system in letters to the NRC dated October 20, 1989, and December 21, 1990, and committed that restoration and documented confirmation of the EE580 data base would be completed by August 15, 1991. The letters noted that 6000 of the original 100,000 open items still remained to be resolved.

NRC Inspection Report 50-528/91-05, 50-529/91-05, 50-530/91-05 identified that an internal licensee letter dated January 31, 1991, determined that there were approximately 2200 open items remaining to be corrected.

The licensee documented that they were unable to retrieve 741 lost EE580 installation cards in an internal letter dated August 6, 1991. The licensee stated that this action was acceptable based on satisfactory unit operations, notation in the data base that these installations had outstanding cards, and the fact that the loss of the cards was not technically significant, since the circuits would be reverified by their current design process prior to any changes.

7.1 Discussion

The inspector reviewed the EE580 system to ascertain if recent modifications had been correctly entered into the system and to ascertain if the existing data base had been updated as committed to correct the previously noted problems.

The inspector determined that licensee Procedures 81AC-0CC07, Revision 3, "Cable and Raceway Control & Tracking System," 81PR-0D02, Revision 4, "Plant Design Change Program," 81DP-0DC03, Revision 5, "Final Engineering," and 81DP-0CC25, PCN 01, "Cable and Raceway Control & Tracking System Activities," adequately controlled changes to the EE580 data base. In addition, the inspector noted that the licensee's Quality Audits and Monitoring Department Audit Report 92-011, "Software Quality Assurance," verified that the EE580 program had a validation and verification method that was initiated when changes to the EE580 system were made.

The inspector selected six cable trays, including two with cables installed in 1993, and verified that the number, types, and sizes of cables in these trays matched the EE580 data base. The inspector determined that the installations matched the EE580 data base, except for one cable type which had a slight difference in the cable diameter; the installed cables were approximately 1.1 inches in diameter, whereas the EE580 data base showed them to be 1.4 inches in diameter. The licensee corrected the EE580 data base.

The inspector reviewed discrepancy records from 1990 through 1994 and determined that Quality Deficiency Reports (and other report types) were being issued to request engineering resolution of any differences found between the EE580 data base and field installations. Based on review of these records, the inspector considered that the problems were not indicative of a systematic problem with maintaining the EE580 data base.

The inspector determined that Quality Control verified most aspects of safety-related EE580 data base related installations. As noted in NRC Inspection Report 50-528/89-12; 50-529/89-12; 50-530/89-12, quality control also verified initial EE580 installations. During the inspection, the licensee stated that the number of missing cards had been reduced to 612, of which 179 involved safety-related equipment. The inspector noted that the licensee had based acceptability of the missing data partly on unit operation. The licensee stated that the 714 missing cards from 1991 had been reduced to 612 as the missing information was reverified by new changes or missing cards were found.

The inspector noted that 10 CFR Part 50, Appendix R, safe shutdown criteria depended on exact knowledge of cable routing within and between fire areas. The inspector questioned how unit operation would show that the EE580 data base was correct with respect to cable routing. The licensee reviewed the equipment covered by the 612 missing cards and determined that 10 involved cables, 5 of which were 10 CFR Part 50, Appendix R, cables. The licensee determined that the missing cards for three of the Appendix R cables did not involve any changes to cable routing, and that no design changes were issued which made changes to the other two cables during the time that the missing cards were originally issued. The licensee concluded that no 10 CFR Part 50, Appendix R, cable routings were involved in the 612 missing cards. The licensee also reviewed the other five cables, determined that only two were active, and sighted the routing of these cables where they were accessible. The licensee determined that the EE580 system matched the installations.

The licensee determined that only 179 of the missing cards were safety-related. The licensee stated that they intended to sight equipment as necessary to verify that the missing cards did not affect any installations.

The inspector determined that Procedure 70DP-0DC02, Revision 4, "System Turnover," required engineering signature verification that the EE580 system had been updated using field verified installation cards for all design changes.

The inspector reviewed completed EE580 cards and did not identify any problems.

The inspector reviewed a recent modification for station blackout and verified that selected information from this modification had been correctly entered in the EE580 data base.

7.2 Conclusion

The inspector concluded that licensee procedures were acceptable to properly enter new changes in the EE580 data base and resolve any differences between field conditions and the EE580 data base prior to making any design modifications.

The inspector concluded that the licensee's decision to suspend actions to locate the 714 missing EE580 installation cards did not constitute a failure of the licensee to perform the committed actions associated with the EE580 data base.

The inspector concluded that the licensee's review of cable installations was adequate to ensure that safety-related cable routing information was correct and that the licensee's stated action to sight installations involving the missing 179 safety-related EE580 cards was adequate.

ATTACHMENT

1 Persons Contacted

1.1 Arizona Public Service Company

R. Adney, Plant Manager, Unit 3
*J. Bailey, Vice President, Nuclear Engineering & Projects
L. Clyde, Operations Manager, Unit 3
*P. Crawley, Director, Nuclear Fuels Management
E. Dutton, Supervisor, Quality Control, Unit 2
A. Fakhar, Manager, Site Mechanical Engineering
*R. Flood, Plant Manager, Unit 2
*D. Garchow, Director, Site Technical Support
*B. Grabo, Section Leader Compliance, Nuclear Regulatory Affairs
*T. Gray, Supervisor, Radiation Engineering
*W. Ide, Plant Manager, Unit 1
M. Kerwin, Maintenance Manager, Unit 3
*A. Krainik, Manager, Nuclear Regulatory Affairs
*D. Larkin, Senior Engineer, Nuclear Regulatory Affairs
*J. Levine, Vice President, Nuclear Production
*D. Mauldin, Director, Site Maintenance and Modifications
*G. Overbeck, Assistant to Vice President, Nuclear Projects
F. Riedel, Operations Manager, Unit 1
*C. Russo, Department Leader, Nuclear Assurance, Maintenance
*J. Scott, Assistant Plant Manager, Unit 3
C. Seaman, Director, Nuclear Assurance
G. Shanker, Department Leader, Nuclear Assurance, Engineering
*W. Simko, Department Leader, Nuclear Assurance, Strategic Analysis
E. Simpson, Vice President, Nuclear Support
J. Velotta, Director, Training
P. Wiley, Operations Manager, Unit 2

1.2 NRC Personnel

*K. Johnston, Senior Resident Inspector
*H. Freeman, Resident Inspector
*J. Kramer, Resident Inspector
*A. MacDougall, Resident Inspector

1.3 Others

*F. Gowers, Site Representative, El Paso Electric

* Denotes personnel in attendance at the exit meeting held with the NRC resident inspectors on July 27, 1994.

2 EXIT MEETING

An exit meeting was conducted on July 27, 1994. During this meeting, the inspectors summarized the scope and findings of the report. The licensee

acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.