ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-528/95-10
50-529/95-10
50-530/95-10

Licenses: NPF-41
NPF-51
NPF-74

Licensee: Arizona Public Service Company
P.O. Box 53999
Phoenix, Arizona 85072-3999

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

Inspection At: Maricopa County, Arizona

Inspection Conducted: April 9 through May 20, 1995

Inspectors: K. Johnston, Senior Resident Inspector
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Approved: Howard J. Wong 6/16/95
Howard Wong, Chief, Reactor Projects Branch F Date

Inspection Summary

Areas Inspected (Units 1, 2, and 3): Routine, announced inspection of onsite response to plant events, operational safety, maintenance and surveillance activities, onsite engineering, and the Employee Concerns Program.

Results (Units 1, 2, and 3):

Plant Operations

Overall, performance in the area of plant operations was good. The Unit 1 midloop operation went very smoothly. Inspectors observed a cautious approach to the evolution, with good crew briefings and well established command and control. Additionally, operators responded well to the loss of reactor coolant system letdown resulting from a failed instrument fitting on a common charging line.

However, the licensee's evaluation of operation's use of an out of calibration boronometer to obtain a Technical Specification required reactor coolant system sample described in an LER did not adequately address the cause of the

event and did not identify corrective actions which were applicable to the problem. The licensee's internal review was also incomplete in that it did not address the barriers in place which should have alerted the operators to the uncalibrated boronometer.

Maintenance

Maintenance work was observed to be good. There was noted progress in the licensee's efforts to address valve packing leaks by implementing a comprehensive valve packing program. However, there were some indications that maintenance personnel did not place much emphasis on work instructions. In one example, work was performed on an air operated valve without work instructions at the job site. In another example, an inverter maintenance procedure was issued for Unit 1 work with numerous pen and ink changes which were over two years old. The inspectors found that one of the pen and ink changes was missing due to a duplication error. The changes made the procedure difficult to follow.

Engineering

The technical support to plant operations and maintenance continued to be very good. The licensee had addressed weaknesses in environmental qualification (EQ) monitoring, allowing them to compare actual plant environmental conditions with the previously calculated EQ basis documents. It was noted that some aspects of this monitoring lacked engineering rigor.

The engineering evaluation of the failure of Unit 2 containment spray Valve SIA-664 during testing in August 1994 was found to be inadequate. The licensee missed a number of opportunities to identify that the valve was degraded, including indications in motor operated valve testing data. The inspector's questions resulted in the licensee determining that the containment spray system was inoperable for a period of 19 days, which was a violation of plant Technical Specifications.

Management Oversight

While the licensee had made progress in their Employee Concerns Program (ECP) and the Management Issues Tracking and Resolution (MITR) programs and employees expressed satisfaction with the efforts of the ECP, the inspector identified some programmatic weaknesses. These weaknesses, which primarily involved the thoroughness of evaluations and formal communications to the concerned employee, could erode the confidence employees have in management's concern for their issues if not addressed promptly.

The two issues in the enclosed report that are the subject of the Notice of Violation involved concerns that had been raised previously by inspectors, but licensee followup was weak and not thorough. Only after questions and prompting by the inspector were comprehensive evaluations conducted.

Summary of Inspection Findings:

- One violation was identified (529/9510-01) regarding the use of an uncalibrated boronometer to satisfy a Technical Specification (Section 7.1). Both LER 529/94-008 and Unresolved Item 529/9431-06, concerning the same subject, were closed.

- One violation was identified (529/9510-02) regarding the failure to comply with the Technical Specification action statement for an inoperable containment spray system valve (Section 7.2). Unresolved Item 529/9426-02, concerning the same subject, was closed.

- Unresolved Item 528/9431-01, concerning a leaking Unit 1 letdown isolation valve, was reviewed and left open pending the completion of a licensee assessment (Section 8.1).

- Unresolved Item 528/9426-04, concerning the environmental qualification of auxiliary feedwater system valves, was closed (Section 8.2).

Attachments:

1. Persons Contacted and Exit Meeting
2. Acronyms

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period in a refueling outage with core offload in progress. On April 9, the licensee completed core offload. On April 27, the licensee commenced core reload and on April 30 a fuel assembly got lodged as it was lowered into the core. The licensee requested and was granted a Notice of Enforcement Discretion to allow a higher refueling bridge overload limit. On May 1, the licensee successfully lifted the fuel assembly and recommenced core reload (Section 2.1). On May 20, the unit entered Mode 3 and the inspection period ended with a reactor coolant system heatup in progress.

1.2 Unit 2

Unit 2 began the inspection period at 100 percent power. On April 11, operators reduced power to 40 percent to repair a condenser tube leak that developed in the 2C condenser hotwell. The licensee repaired the leaking tubes and returned the plant to 100 percent power on April 11. On May 10, power was reduced to 40 percent due to a large intrusion of impurities into the steam generators (Section 2.2). The licensee restored steam generator chemistry to normal and returned to plant to 100 percent on May 11.

1.3 Unit 3

Unit 3 started and ended the inspection period at 100 percent power.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Fuel Assembly Stuck During Core Reload - Unit 1

On April 30, during the Unit 1 core reload, personnel on the refueling bridge received an underload alarm as they were lowering a fuel assembly into core location E-12. During the subsequent attempt to raise the assembly, a refueling bridge overload interlock was received. Visual examination revealed that the assembly in adjacent core location, F-12, had not been positioned properly and was preventing the movement of the assembly in position E-12. The fuel assembly in E-12 was approximately 2 feet above the core support plate and was restrained on three sides by previously loaded fuel assemblies.

The licensee made an attempt at moving the assembly in a horizontal direction by operating the refueling machine manually. The refueling operators were only able to move it approximately one inch before the load cell indicated that the fuel assembly was stuck. After unsuccessful efforts to raise the assembly, the licensee put the refueling operations on hold pending further evaluation.

Early in the morning on May 1, the licensee placed a restraining device on the fuel assembly in the F-12 core location. The restraining device was designed to prevent the F-12 fuel assembly from tipping while efforts were made to dislodge the fuel assembly in the E-12 core location. Refueling operators again attempted to move the stuck assembly manually in the horizontal direction in which it was not blocked by another assembly. The overload limit was reached and the movement was suspended.

The licensee subsequently requested a Notice of Enforcement Discretion from Region IV to allow raising the Technical Specification (TS) refueling machine hoist overload limit from 1600 lbs to 1800 lbs. The licensee and the fuel vendor had determined that the additional 200 lbs would not impact the core internals or the pressure vessel. They suspected that there could be damage to the fuel assembly grid straps, but did not anticipate fuel rod damage. Region IV granted the one time limit adjustment at 8:45 a.m. (MST) on May 1, 1995, based on a review of the licensee's assessment.

On May 1, at 1:30 p.m. (MST), refueling personnel were able to free the stuck fuel assembly with a force of 150 lbs over the TS limit. The licensee proceeded to move the fuel assembly and adjacent assemblies to the spent fuel pool for a detailed inspection.

The inspectors observed most of the significant attempts at lifting the fuel assembly on April 30 and May 1. The inspectors observed that the refueling operators proceeded with caution and in accordance with pre-established strategy and limits.

The cause of the fuel assembly to become stuck appears to have been the failure to properly seat the fuel assembly in core location F-12. The licensee initiated a condition report/disposition request (CRDR) to perform a review of the failure to seat the fuel assembly. The assembly which was stuck was one of the last 25 assemblies to be put into the core. Earlier in core reload, the licensee used a high powered light and a video camera located low in the core to provide good monitoring of the reload. However, as the core was filled, the camera and light had to be removed due to its proximity to fuel being moved and the high radiation fields which could damage the video camera. As a result, refueling operators verified that the final fuel assemblies were properly set using binoculars to see if the assembly was located on the core support pins and by reading the "Z" coordinate on the refueling machine to verify that the assembly was fully lowered. In the case of the fuel assembly in location F-12, the "Z" coordinate indicated the assembly was fully lowered. A refueling operator's visual examination by binocular inappropriately concluded that the assembly was properly seated.

The inspector reviewed past performance in refueling to determine if there had been previous problems during later stages of the core reload. The inspector noted that there had not been previous problems. The licensee stated that they planned to develop a high powered light designed so that it could be kept in the core to the last stages of the fuel loading and that this will be in

place for the Unit 3 refueling outage scheduled for October 1995. The inspector found this to be appropriate.

No violations of NRC requirements were identified.

2.2 Power Reduction Due to Increased Sodium in the Steam Generators - Unit 2

On May 10, at approximately 10:45 a.m., operators observed a sharp increase in the 1A hotwell sodium level and a corresponding rise in steam generator sodium levels. Within minutes, the steam generator sodium levels increased from normal levels of less than one part per billion (ppb) to over 300 ppb. The operators entered the condenser tube rupture procedure and began reducing power to 40 percent.

At approximately 12:30 p.m., the plant was stabilized at 40 percent power and the 1A condenser shell was isolated. The licensee performed a tube inspection and did not identify any leaking circulating water (CW) tubes. They suspected that the source of the impurities was the auxiliary steam condenser tank that returns to the 1A hotwell. The licensee secured the auxiliary steam condenser tank to the hotwell and was able to reduce the sodium and sulfate levels in both steam generators.

On May 11, the licensee returned the unit to 100 percent power. The inspector observed portions of the downpower from the control room and noted very good command and control from both the shift supervisor and the control room supervisor. The inspector also noted that the operators responded quickly to the event and had all the condensate demineralizers in service within 15 minutes of detecting the increase in hotwell sodium levels. As a result, the operators limited the subsequent peak of the steam generator sodium levels. The inspector concluded that the operators were very sensitive to the importance of steam generator chemistry on the integrity of steam generator tubes.

The licensee was investigating the exact source of the impurities in the auxiliary steam system and suspected a leaking isolation valve between the auxiliary steam and the condenser hotwell and a tube leak in the liquid radioactive system evaporator. The inspector will review the licensee's corrective actions during future routine inspections.

2.3 Loss of Letdown - Unit 2

On May 19, a swage lock connector for the Unit 2 common charging line pressure transmitter, CHA-PT-212, failed resulting in a charging header to atmosphere leak in the "E" charging pump room. At the time of the event, the "E" and the "B" charging pumps were in operation and the "A" charging pump had a freeze seal applied to the discharge line to allow repairs to the discharge isolation valve. The operators had conducted a briefing on the contingency actions to isolate seal injection and stop the remaining charging pumps if the freeze seal failed.

At approximately 10:50 p.m., control room operators received a charging system trouble alarm and noticed that both the charging header pressure and flow instruments were reading zero. Within a minute, letdown automatically isolated on high regenerative heat exchanger outlet temperature. The operators implemented the previously briefed contingency actions and stopped the running charging pumps and isolated seal injection. The leak was stopped when the operating charging pumps were stopped. The licensee estimated that about 300 gallons of charging system water was pumped into the "E" charging pump room. The operators did not detect any reactor coolant system leakage during the event.

The inspector reviewed the applicable alarm response and operating procedures and discussed the event with the control room operators. The inspector noted that the operators appropriately entered TS 3.0.3 due to the loss of all charging pumps and the loss of an operable boration flow path. The licensee was in TS 3.0.3 for about 45 minutes. The inspector also noted that the licensee initiated a CRDR to evaluate the root cause of the swage lock fitting failure. The inspector concluded that the operator response to the event was good and that the licensee's corrective actions were appropriate. The licensee planned to submit a Licensee Event Report (LER). The inspector will review the licensee's evaluation of the event's cause and proposed corrective actions in a future inspection report.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Reactor Coolant System Midloop Operations - Unit 1

On May 12, the inspector observed the licensee drain the RCS to midloop to remove steam generator nozzle dams. The inspector reviewed the prerequisites for draining to midloop and noted no discrepancies. The inspector noted that the operations staff conducted excellent briefings and maintained good command and control throughout the evolution. The inspector noted that the operators used all available level indications as the level approached a midloop condition and that the operators often verified the levels were within acceptable deviations. The inspector observed active participation of the shift technical advisor and the nuclear assurance evaluator. The inspector concluded that the licensee performance during the midloop evolution was good.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 125 VDC Vital Inverters - Unit 1

On April 26, 1995, the inspector observed portions of maintenance procedure 32MT-9ZZ58, "Maintenance of Inverters." The electricians indicated that the procedure was difficult to follow and the inspector noted that the procedure had numerous steps and pages that were crossed out and hand written steps were inserted. The changes resulted from a temporarily approved procedure action (TAPA) written in April 1993. The licensee approved the TAPA, but did not formally incorporate the TAPA into the procedure.

The inspector reviewed the completed procedure and noted that the content was technically accurate; however, the inspector noted a controlled copy of the procedure appeared to have a hand written step missing at the bottom of the page due to reproduction. The inspector notified electrical maintenance about the discrepancy. The licensee reviewed the original TAPA, and recovered the missing step. The inspector noted that the step directed the user to a subsequent section in the procedure and did not contain technical information. The licensee determined that the missing step had not impacted the performance of work. The licensee subsequently re-issued the procedure which included all the hand written steps.

Nuclear Assurance issued a CRDR to evaluate the problem. The licensee looked at all of the electrical maintenance procedures and determined this was the only procedure which had pen and ink changes. The inspector noted that the technicians continued to use the procedure although the procedure did not work as written. In addition, the inspector noted the technicians did not adequately document steps marked NA (not applicable). The inspector discussed the maintenance workers' weaknesses with the electrical maintenance department leader. The electrical maintenance department leader acknowledged the weaknesses, indicated that the technician performance did not meet his expectations, and stated he would discuss the weaknesses with the technicians. The inspector concluded that the technicians were knowledgeable about the maintenance task and followed a logical progression through the procedure and correctly performed the task, although one step was missing.

4.2 Air Operated Valve Diaphragm Replacement

On April 21, the inspector observed a preventative maintenance task to replace internal components in the operator for Valve SIA UV 560, the inside containment isolation valve to the reactor drain tank. The inspector observed the mechanic change the o-rings on the stem bushing and install a new diaphragm for the air operator.

The inspector noted that the mechanic lubricated and installed the o-rings and installed the new diaphragm, but did not have the work order available at the job site. The mechanic stated that another member of his team had taken the package back to the shop to get a tool. The inspector noted that the mechanic could not review the actions he completed because he could not refer to the work order instructions.

The inspector discussed this observation with the responsible mechanical maintenance section leader who agreed that not having the WO available at the job site did not meet management's expectation. The inspector also reviewed the WO instructions and discussed the scope of the job with the technician. The inspector concluded that the mechanic completed the job in accordance with the WO instructions.

The section leader counseled the mechanic concerning management's expectations for having the work order available at the job site. The inspector concluded

that the licensee's corrective actions were appropriate and that this appeared to be an isolated incident.

4.3 Valve Packing Program Review

The inspector conducted a review of the licensee's valve packing program to determine how the licensee was identifying and correcting old packing configurations in safety-related valves. The inspector wanted to determine the number of other safety-related motor operated valves (MOVs) which could have had obsolete packing configurations like the 10 braided rings found in Valve SIA 664 that subsequently prevented the valve from closing (Section 8.2).

The inspector reviewed the licensee's valve packing procedure and specification, interviewed the maintenance engineer responsible for the valve packing program, observed repacking of several valves, and conducted walkdowns to assess the condition of the valve packing.

4.3.1 Program Description

The licensee's valve packing program required valves to be repacked using a standard five ring packing configuration consisting of three die-formed rings and two braided end rings. The Maintenance Department planned to repack safety-related valves as part of a preventive maintenance effort instead of repacking in response to identified leaks as has been past practice. The licensee's program allowed some variation in this configuration depending on the depth of the stuffing box and the existence and location of a leak off port. The inspector also noted that valves with unique packing configurations and/or materials were individually exempted from the valve packing program. The inspector concluded that the licensee's packing program was adequately described in the procedure and packing specification.

The inspector noted that the mechanical maintenance engineering was the process owner of the licensee's valve packing program and was generating a valve packing data base that contained specific packing information for every valve in the plant. The data base was generated from information gathered in the field during valve packing replacements. The valve specific information was recorded on a valve survey data sheet (VSDS). The VSDS included information such as the dimensions of the stuffing box, the type, number and order of packing rings and spacers, and the as-left packing gland torque. The inspector concluded that the licensee's effort to generate an accurate data base of the field condition of packing was a strength.

4.3.2 Observation of Work in Field

The inspector observed mechanics repack Valve SIA 647, a motor-operated high pressure safety injection system valve in Unit 2, and Valve CHB 337, a manual charging system valve in Unit 1. The inspector noted that the work was performed by contractors, The Atlantic Group. The inspector concluded that the valve repacking activities were appropriately conducted.

The Director of Maintenance hired The Atlantic Group to repack the valves in the plant as part of the "Level 1" action to reduce the number of packing leaks in the plant. The inspector noted that during the Unit 1 refueling outage there were a total of 82 valves that were repacked and 16 of these valves were safety-related MOVs. During the Unit 2 refueling outage completed in March 1995, a total of 95 valves were repacked and 32 were safety-related MOVs. The inspector concluded that the licensee was aggressively implementing the valve repacking program to improve the material condition of the plant and the performance of the valves. The inspector also noted that the licensee was placing a high priority on repacking the safety-related MOVs.

4.3.3 Plant Walkdown

The inspector identified three MOVs with apparent packing leaks in Unit 2 on May 3 during a routine plant tour. The inspector informed the valve services group and they conducted a walkdown of the safety-related MOVs in Unit 2 and identified nine more valves with apparent packing leaks. The licensee subsequently determined that eight of the 12 leaking valves had been identified two weeks earlier during operations and engineering system walkdowns.

The inspector determined that four of the leaking valves had been repacked during the Unit 2 outage in March 1994. The inspector noted that Valve CH-524 had a significant leak and appeared to be actively leaking. The other three valves had small amounts of boron on the stem but did not appear to be actively leaking.

The inspector reviewed the VSDS for Valve CH-524 and noted that the valve was properly packed and that the packing gland was properly tightened. The inspector noted that for motor-operated valves the mechanics tighten the packing gland towards the low end of the required torque range. The valve services group subsequently performs an as-left static diagnostic test and ensures that the packing load is within the proper range. The diagnostic test procedure has general guidance that the running load should be around 1000 pounds for each inch of stem diameter. The procedure also includes guidance that the packing should be tightened if the running load is low. The inspector concluded that the licensee's procedures provided adequate guidance to ensure that the packing of MOVs was not tightened too much, which would prevent operation of the valve, or not tightened enough, which would allow the valve to leak.

The inspector noted that the as-left diagnostic test was performed with the system filled, but not at normal operating pressure and temperature. As a result, the packing may have loosened causing the valve to leak when the normal system pressure was reached. The licensee agreed to evaluate optimizing when as-left diagnostic tests were conducted to minimize the potential for subsequent packing leaks. The inspector concluded that the licensee's actions were appropriate.

4.4 Other Maintenance Work Observed

The inspector observed portions of the work listed below:

- Feedwater isolation valve accumulator nitrogen pre-charge - Unit 1.

- Disassembly of turbine driven auxiliary feedwater governor valve - Unit 1.

5 SURVEILLANCE OBSERVATION (61726)

5.1 Main Steam Isolation Valve Testing - Unit 2

On May 9, the inspector observed a portion of main steam isolation valve (MSIV) partial stroke testing in Unit 2. The inspector observed good command and control of the test by the control room supervisor and the reactor operator performing the test. For example, the operators had briefed contingency actions in the event a MSIV went closed and were closely monitoring the MSIV accumulator pressure for any abnormal trends during the test. The inspector also observed good communications between the auxiliary operator and the control room operators.

6 EMPLOYEE CONCERNS PROGRAM REVIEW

The inspector performed a review of the licensee's Employee Concerns program (ECP) and Management Issues Tracking and Resolution program (MITR). The ECP provided employees a method for independent review of technical and safety concerns which they did not consider would be adequately resolved through normal processes. The MITR provide employees similar review for personnel and administrative concerns. The inspector noted the following concerns:

- The MITR program was not covered by a formal administrative procedure. As a result, there were no consistent requirements for the content of MITR files or how they were to be closed. Review of Files 94-01, 94-06, 94-09, and 94-10 identified the following concerns:

  - The files did not include appropriate documentation of evaluation conclusions.

  - The files did not include final closure correspondence to the concerned employee as to how each of his concerns had been resolved.

  - The files did not indicate any cause evaluation or corrective action for problems that had resulted in valid employee concerns.

- MITR 94-43 addressed a discrimination concern involving an engineer having raised safety concerns about ADV problems in a report to the NRC. It was not clear from the file that the concern received an

appropriately independent evaluation, in that the concern was evaluated by the Vice President to whom the alleged discriminating manager was a direct report. The file did not clearly indicate the basis for Human Resources department conclusion that this 10 CFR 50.7 concern received a proper independent evaluation.

- The inspector identified the following concerns in a review of ECP administrative guidelines ECP01, ECP02, ECP03, and ECP Files 94-07-03, 94-08-05, 94-09-02, 94-10-03, and 95-01-07:

  - ECP Administrative Guideline ECP02 (Handling ECP Concerns) does not require an initial letter to the concerned employee which clearly documents the scope of his concerns, the plan of action to evaluate the concerns, or the target schedule for completing the evaluation, nor does the guideline require a final closure letter to the employee which documents the conclusions and actions resulting from the ECP evaluation.

  - File 95-01-07 did not indicate any cause evaluation or corrective action for the mishandled CRDR investigation problem identified during the ECP evaluation.

  - ECP Administrative Guideline ECP03 (ECP File Open Action Tracking) does not address completion of file closure followup with the employee.

  - The closure followup for File 94-10-03 indicated that the employee considered that the hostile work environment in his work group had "drastically improved," however, NRC interview with the concerned employee indicated that the employee still considers that supervisors in his work group are hostile to employees raising safety concerns.

- The inspector interviewed six employees who recently had discrimination concerns evaluated by the ECP and MITR programs. These employees consistently expressed satisfaction with the performance of the ECP program; however, some stated that they were not confident with the MITR program, indicating that the Human Resources department was not viewed as a credible organization for representing employee's best interests. The employees also stated that senior licensee managers had increased their credibility in recent months such that employees were confident that they could come to senior managers and receive fair treatment, without fear of retribution. However, several of the same employees stated that they did not have similar confidence in lower levels of licensee management and supervision.

While progress had been made in the MITR and ECP and employees seemed generally satisfied with the ECP, some programmatic weaknesses were identified. The inspector discussed these findings with licensee senior

management responsible for the ECP and MITR programs. They concurred with the inspector's observations and planned to implement appropriate corrective actions.

7 FOLLOWUP - MAINTENANCE (92902)

7.1 (Closed) LER 529/94-008 and (Closed) Unresolved Item 529/9431-06: Use Of Uncalibrated Boronometer Caused a TS Action to be Missed

This LER involved operator's use of an uncalibrated boronometer to verify reactor coolant system boron concentration in order to comply with the compensatory action requirements of TS 3.1.2.7 which applied in February and March 1994 when a startup channel was removed from service.

7.1.1 Background

Instrumentation and Controls (I&C) technicians began a routine 18-month calibration of the Unit 2 boronometer in February 1993. They found that one of the instrument's power supplies did not meet the calibration specifications. The I&C technicians stopped work, left the boronometer in service, notified the Shift Supervisor, and proceeded to attempt to procure a new power supply. The boronometer appeared to be operating adequately in that it closely tracked reactor coolant system boron concentration.

The I&C group performed work on the boronometer sporadically until November 1994. Near the time the calibration was completed in November 1994, the licensee identified that the boronometer may have been used by operators, during the Unit 2 refueling outage in February and March 1994, to satisfy the compensatory action requirements of TS 3.1.2.7 which apply when a startup channel was removed from service. The licensee concluded this review in January 1995, having found that the boronometer was relied on in three occasions. On one of the cccasions, if no credit is provided for the use of the boronometer to meet the TS action, the TS action was not complied with. The inspector noted that, despite the questionable calibration status of the boronometer, during the period it was used for TS compliance, it remained within 1 to 2 percent of the RCS samples.

The inspector reviewed the LER and found that there were significant weaknesses in the evaluation of the cause of the event and the corrective actions taken. Further, the inspector found that the licensee's internal evaluations which support the LER were weak.

7.1.2 Evaluation of the Cause of the Event - Operations

The LER statement of cause states, in part:

> "An evaluation was performed in accordance with the APS Incident Investigation Program. The evaluation concluded that the apparent cause of the boronometer past calibration was a lack of concern for the instrument being calibrated correctly."

The inspector noted that the cause statement did not address the barrier necessary to prevent an operator from using an boronometer of questionable calibration to satisfy a TS requirement. The inspector determined, through discussions with operations personnel, that the appropriate administrative control would have been for operators to have made a control room deficiency log (CRDL) entry with a CRDL tag placed on the control board.

The licensee's initial CRDR (2-4-343) evaluation identified that I&C had informed the shift supervisor that the calibration of the boronometer had not been completed. The CRDR noted that a second CRDR (2-4-471) was initiated for operations to evaluate how the boronometer was allowed to be used while it was being calibrated. CRDR 2-4-471 identified that the issue was reportable under 10 CFR 50.73, but did not provide any root cause review. The inspector found that, CRDR 2-4-343 was closed based on the evaluation to be performed in CRDR 2-4-471. However, CRDR 2-4-471 was subsequently closed without a documented evaluation of cause and without further corrective actions based on the evaluation provided in CRDR 2-4-343. As a result, there was no documented evaluation of operations failure to identify and tag the boronometer deficiency.

7.1.3 Evaluation of the Cause of the Event - Maintenance

The licensee had made some effort to identify what the inspector considered to be a contributing cause concerning the lack of a timely calibration of the boronometer. The licensee identified that the calibration had not been given priority due to the fragmentation of the responsibility for the resolution of equipment reliability problems.

The inspector reviewed this evaluation and found that it lacked rigor. The preventive maintenance (PM) task to calibrate the boronometer was considered to be an "operations surveillance test no-waive PM." The PM task, which had an 18-month frequency, had last been completed on September 26, 1991, and was due on March 26, 1993. The licensee allowed a grace period to August 23, 1993. The boronometer was recognized in its PM basis documentation as providing post-accident indication in accordance with Regulatory Guide 1.97.

On July 29, 1993, an I&C foreman performed a PM work order disposition report to delay the calibration of the boronometer. No justification was provided and the due date was extended to September 26, 1993. The work was not completed in September 1993 and no further delay requests were documented.

In September 1994, a Shift Technical Advisor discovered that the PM had not been completed. The I&C section leader performed a PM work order disposition report to waive the original PM task. CRDR 2-4-343 was initiated and the calibration was completed in November 1994 under a new work order. The waiver of a "no-waive" PM was considered an Unresolved Item in Inspection Report 94-31.

The evaluation in CRDR 2-4-343, which was included in the LER, discussed the lack of priority placed on calibrating the boronometer. However, it did not

address the specifics of what barriers are provided to ensure that priority is appropriately placed and how these barriers may have been defeated. Specifically:

- Regarding the disposition on July 29, 1993, how could a "no-waive" PM be delayed with no documented justification for the delay?

- After the first delay expired on September 26, 1993, why were there no subsequent "no-waive" PM dispositions documented?

- Why were there no controls in place to ensure that post-accident monitoring instrumentation referred to in the Updated Final Safety Analysis Report be returned to service in a expeditious manner?

7.1.4 Evaluation of Corrective Actions

The inspector reviewed the actions to prevent recurrence discussed in the LER. The LER stated that the following step had been added to the PM Process and Activities procedure:

> "I&C Section/Team Leaders shall refer out-of tolerance results found during Operations Surveillance Tests "NO WAIVE" PMs on installed plant equipment to the duty STA or other appropriate engineering personnel. The STA/engineer shall perform a documented evaluation of the significance of the problem or deficiency and ensure that a CRDR is generated, if required."

The inspector found that this step did not address any of the problems noted in the LERs or the CRDRs associated with the boronometer. The inspector interviewed a Shift Technical Advisor (STA), a Control Room Supervisor, a Shift Supervisor, an I&C Team Leader, and an I&C Section leader and determined this step was intended to ensure that out-of-tolerance results are appropriately reviewed for their impact on tests for which they may have been relied upon and to trend and assess reliability of the instrument. Typically, as-found out-of-tolerance results are quickly resolved and the instrument placed back in service with no impact on ongoing plant operations. Therefore, I&C typically refers subsequent out-of-tolerance reviews to I&C maintenance engineers and not the STAs.

Furthermore, the inspector noted that the boronometer calibration procedure included two steps requiring I&C to notify the control room of out-of-tolerance findings and that this was done for the subject calibrations.

The LER concludes by stating that the evaluation of the event had not been completed. The LER was issued on February 7, 1995. All open evaluations of the issue were closed by February 14, 1995, without further documented review.

7.1.5 Conclusion

The failure to assure that an instrument used to meet TS requirements was properly calibrated is a violation of 10 CFR Part 50, Appendix B, Criterion XII, concerning the control of measuring and test equipment (Violation 529/9510-01). The inspector noted that the licensee identified this violation in December 1994. However, the inspector considered that the licensee had not performed an adequate cause review nor identified appropriate corrective actions to prevent recurrence. The inspector considered this to be potentially significant in this case since it appeared that both licensee's corrective actions and event report programs failed to ensure that an adequate review was performed.

7.2 (Closed) Unresolved Item 50-529/94-26-02: Failure of Motor-Operated Valve to Close

This unresolved item involved the failure of a Unit 2 containment spray (CS) miniflow isolation Valve SIA-664 to close during a surveillance test on September 5, 1994. The valve also failed to close on August 17, 1994, when operators attempted to verify the valve was open by closing the valve.

The licensee conducted a root cause of failure analysis and determined that the failure of Valve SIA-664 to close was caused by an excessive running load. The licensee determined that the excessive running load was caused by an obsolete packing configuration (10 braided rings and a lantern ring) that was originally installed in the valve. The valve was repacked using low resistance packing, manufactured by Argo, and returned to service. The licensee also changed the bill of materials to specify the Argo packing and initiated work requests to repack the Unit 1 CS and low pressure safety injection (LPSI) pumps miniflow valves during the Unit 1 refueling outage in April 1995.

The inspector initiated the unresolved item to assess whether the torque switch (TQS) was correctly set and if the licensee's response to the initial failure to close on August 17 was appropriate. The licensee initiated CRDR 2-4-0301 to address the inspector's questions.

The inspector reviewed the licensee's CRDR evaluation, reviewed all the previous diagnostic traces for Valve SIA-664, and had numerous discussions with members of the valve services group. In summary, the inspector noted the following weaknesses with the licensee's overall response to the problems with Valve SIA-664:

- The licensee did not conduct a thorough review of the issue in response to the unresolved item. The inspector had to prompt a more thorough review which eventually led to discovering that Valve SIA-664 was inoperable between August 17 and September 5, 1994.

- The licensee did not perform a thorough, critical review of past diagnostic traces to assess the future performance of the Valve SIA-664. As a result, the licensee failed to identify an anomaly in the diagnostic traces of Valve SIA-664 which was a precursor to the failures on August 17 and September 5, 1994.

- The licensee did not have any requirements for the technicians analyzing diagnostic traces to perform a qualitative assessment of the quality and shape of the traces. The inspector pointed out to the valve services group the potential problems with not performing this type of qualitative assessment of the diagnostic traces in Inspection Report 50-528/94-13 and the licensee did not provide any additional tools or training to help the technicians recognize trace anomalies.

The inspector noted that the response by the valve services group to this problem was poor, but not typical. For example, the licensee identified and promptly corrected anomalies in butterfly valve traces. This was noted as a strength in Inspection Report 50-528/93-32. However, the inspector concluded that the weaknesses described above highlighted the need for improvement in the use of diagnostic trace information and the thoroughness of evaluations in response to unresolved items.

7.2.1 Licensee's Response to the Unresolved Item

The licensee initiated a CRDR evaluation in response to the unresolved item and concluded that the TQS was properly set and that the operator had sufficient available thrust to close the valve. The licensee reviewed April 1992 diagnostic test data and noted that Valve SIA-664 had about 4800 pounds of available thrust and a running load of 1800 pounds. The September 5, 1994, as-found diagnostic test data showed 2000 pounds of available thrust and a running load of 2500 pounds. The licensee had an upper limit on running load of 2580 pounds. The licensee subsequently concluded that the TQS was properly set and that the higher than normal running load caused the close TQS to interrupt the travel of the valve.

The inspector reviewed the CRDR and had the following observations:

- The licensee had not evaluated the operability of Valve SIA-664 between the two apparent failures to close on August 17 and September 5, 1994.

- The licensee had not determined what would have caused the close TQS to trip if there was still 2000 lbs of available thrust to shut the valve.

The inspector asked the licensee to perform an evaluation of the operability of Valve SIA-664 and to review previous diagnostic traces of Valve SIA-664 to explain the apparent close TQS trip on August 17 and September 5. The licensee subsequently determined that Valve SIA-664 would not have been able to close between the two failures and was, therefore, inoperable for about 19 days.

7.2.2 Operability Evaluation

The inspector reviewed the design basis function of Valve SIA-664 to determine the safety significance of the valve being inoperable and to determine the subsequent impact on the overall operability of the CS system. Valve SIA-664 is normally open to provide a flow path to the refueling water tank (RWT) when the pump is started with the discharge isolation valves shut. Valve SIA-664 receives a recirculation actuation signal (RAS) to close during the recirculation phase of a loss of coolant accident (LOCA).

As described in the licensee's Updated Final Safety Analysis Report, Valve SIA-664 received a close signal to prevent the transfer of radioactive fluid to the RWT, mitigating a potential release in excess of 10 CFR Part 100 limits. Additionally, closing SIA-664 would prevent a loss of inventory in the containment sump that eventually could challenge the operation of the safety injection pumps.

TS 3.6.2.1 required that two independent CS systems be operable with the capability to automatically transfer suction to the containment sump on a RAS. As described above, a specified function of the RAS is to close the CS minimum flow recirculation valves. The action statement of TS 3.6.2.1 allowed the licensee to have one train of CS inoperable for 72 hours. Train A of CS was inoperable for 19 days, from August 17 to September 5, 1994, in violation of TS 3.6.2.1 (Violation 529/9510-02).

The inspector noted that operators would receive an alarm indicating that the Valve SIA-664 did not move to the closed position on a RAS. Manual operation of the valve would be prevented due to the assumed high radiation levels in the auxiliary building. However, operators could secure the operating CS pump and line-up the LPSI pump to provide containment heat removal.

The licensee's probability risk assessment (PRA) group ranked the failure of Valve SIA-664 as having low safety significance during the scoping of the generic letter (GL) 89-10 MOV program. The PRA group did not model a failure of Valve SIA-664 because they assumed operation of a redundant valve in the miniflow line to the RWT (Valve SIA-660) that also received a signal to close on a RAS. Based on this information, the inspector concluded that the safety significance of having Valve SIA-664 inoperable was low.

The licensee determined that Valve SIA-664 being inoperable was reportable and planned to submit an LER. The licensee stated that they would perform an evaluation of the impact on the Part 100 dose limit calculations due to the known failure of Valve SIA-664 and an assumed single failure of the redundant Valve SIA-660.

7.2.3 Diagnostic Trace Anomalies

The licensee reviewed the previous diagnostic traces of Valve SIA-664 in April 1995 and determined that there was an anomaly in the springpack displacement curves at the beginning of the close stroke that had not been previously identified and evaluated.

The licensee typically measures the deflection of the MOV springpack during diagnostic tests. The deflection of the springpack is directly proportional to the output torque of the motor operator. The beginning of a typical spring pack deflection curve shows a steady increase until the valve stem begins to move through the valve packing. At this point, the springpack deflection should stay at a relatively constant value corresponding to the running load. The magnitude of the running load is largely determined by the dynamic friction between the packing and the valve stem. The spring pack deflection curve stays at the running load.value until the valve plug begins to enter the valve seat.. At this point the spingpack displacement rapidly increases until the operator reaches the point where the torque switch trips (TST) and the valve is fully seated. .

The licensee reviewed the springpack deflection curves for Valve SIA-664 and noted that the springpack displacement curves had a large spike at the beginning of the valve stroke that was significantly larger than the displacement corresponding to the running load. The licensee called the magnitude of the spike the breakaway torque and initially thought that it was caused by a combination of the higher than normal packing friction and the unique rotating rising stem (RRS) valve. In the RRS valve, the stem not only moves vertically, but it also rotates through the packing. In most other MOVs, the valve stem goes vertically through the packing with no rotating motion.

The inspector reviewed the previous diagnostic traces for Valve SIA-664 and noted the value of the as-found and as-left breakaway torque, the running load torque, and the torque at TST. The inspector noted that the breakaway torque spikes were consistently larger than the running load and on several occasions were close to challenging the close TQS and operation of the valve. The torque values are recorded as inches of springpack displacement and were as follows:

	May 1989		May 1991		September 1994	
	As-Found	As-Left	As-Found	As-Left	As-Found	As-Left
Break-away torque	0.1335"	0.1490"	0.1771"	0.0820"	0.1362"	0.0171"
Running torque	0.0785"	0.0610"	0.1103"	0.0425"	0.0834"	0.0132"
Torque Switch Trip	0.1685"	0.1645"	0.1674"	0.1923"	0.1537"	0.1771"

7.2.4 Inadequate Corrective Actions

The inspector concluded that the licensee did not evaluate the impact of the breakaway torque spikes on operation of Valve SIA-664 in 1989, 1991, and 1994. Additionally, the inspector determined that the licensee was only trending the minimum available thrust to close the valve and had not recognized the spikes as an anomaly that needed to be trended. The inspector noted that after valve SIA-664 was repacked in 1994 with the Argo packing, the breakaway torque spike was not present in the subsequent traces.

The inspector concluded that the licensee had several opportunities to identify and correct the high breakaway torque which challenged the operability of Valve SIA-664 and did not take appropriate corrective actions. As a result, the valve subsequently failed to perform on two separate occasions. The previous opportunities to identify and correct the condition are outlined below:

7.2.4.1 Initial Review of 1989 and 1991 Traces

The inspector noted that the large breakaway torque existed since the initial 1989 trace and could have been identified during the initial implementation of the GL 89-10 program. For example, the May 1991 as-found trace showed the breakaway torque as high as the torque at TST, a condition which should have caused the valve not to stroke. This fact was not identified and trended. The inspector concluded that the MOV program was still maturing at that time and the licensee apparently did not have enough experience to recognize the torque spike as an anomaly.

7.2.4.2 August 1994 Failure to Close

On August 17, a control room operator attempted to close Valve SIA-664 and an auxiliary operator observed the valve stem rotate about 1/4 of a turn. The control room operator observed both the open and close valve position lights indicating the valve had stopped in mid-position. Control room operators subsequently went to close again and Valve SIA-664 went fully closed. The valve was then successfully stroked five more times.

The inspector noted that Unit 2 operators had not informed the valve services group of the failure of Valve SIA-664 to close (Inspection Report 50-528/94-31). The inspector subsequently informed the valve services group and asked for their assessment of the potential cause of the problem. The valve services group determined that once the valve began to move only the MOV torque or limit switches could have stopped the valve from fully closing. The valve services group did not perform any subsequent testing or inspection of the valve because they assumed that any evidence of the problem was destroyed by repeatedly stroking the valve.

The inspector concluded that as a minimum the licensee should have evaluated the past diagnostic traces of Valve SIA-664 after the August 17 apparent failure to close. Had they reviewed the traces, they could have identified the abnormally high running loads and possibly the breakaway torque anomaly.

The inspector also noted that the licensee had problems with unexplained losses in the available closing torque with similar RRS valves in Units 2 and 3. In some of these cases, there was unusually high running loads caused by friction between the valve plug and the valve seat. The inspector concluded that the licensee should have performed a diagnostic test after the August 17 problem based on the known unpredictable performance of RRS valves. The inspector based this conclusion on the fact that the only real indicator of future performance of an MOV is a diagnostic test and the extent of controls on the use of diagnostic equipment should be commensurate with the degree of uncertainty in the performance of the valve.

The inspector further noted that the licensee had a procedure for troubleshooting MOV failures in August 1994. The stated intent of the procedure was to "provide a guideline for use in troubleshooting MOV actuator failures, and to ensure that the cause of the failure determined, corrected, and documented". The inspector reviewed the procedure and noted that there was a section for troubleshooting a TST which would have eventually led the technicians to perform a diagnostic test.

7.2.4.3 September 1994 Failure to Close

The inspector noted that the licensee had another opportunity to identify and evaluate the breakaway torque spikes after the September 1994 failure to close and subsequent root cause of failure analysis. The inspector noted that a review of the as-found trace on September 5 clearly shows the break away torque spike and the as-left trace after the packing replacement does not have the breakaway torque anomaly. The inspector noted that although the valve services technicians were analyzing the diagnostic traces, they were not critically reviewing the quality of the trace and were not sensitive to changes in the characteristics of the curves. The inspector concluded that if the licensee had done a qualitative review of the shape of the as-left curve to the as-found curve they should have recognized the breakaway torque anomaly.

The inspector had a similar concern with the adequacy of diagnostic trace reviews following the failure of another RRS valve to close during a differential pressure test in March 1994 (Inspection Reports 50-528/94-09, Section 2.1, and

50-528/94-13, Section 8.1). This particular failure was caused by having the wrong motor pinion gear ratio that caused the valve to stroke too fast. A qualitative review of the as-left and as-found traces clearly showed the significant drop in stroke time. The inspector subsequently concluded that the licensee did not have appropriate acceptance criteria because they did not review the relative shape of the curves. A noncited violation was issued based on the licensee's indication that a qualitative assessment of the shape of the diagnostic trace would be included in the diagnostic test procedure.

The inspector reviewed the current diagnostic test procedure and noted that the licensee still did not require a qualitative review of the shape and quality of the trace and a comparison of the as-left to the as-found trace. The licensee subsequently determined that there was a CRDR action to add the qualitative assessment to the diagnostic testing procedure, but that it was incorrectly closed without the action being completed.

7.2.5 Transportability of Breakaway Torque Anomaly

The inspector asked the licensee what were the most susceptible valves to the increased packing loads and if they had the new low resistance Argo packing installed. The licensee determined that the most susceptible valves were the RRS valves with Limitorque SMC-04 actuators. There are 55 of these valves in the high pressure safety injection, LPSI, CS and reactor coolant systems in all three units. The licensee had repacked all but eight of these valves with the new Argo packing. The licensee could not find any documentation that two of the eight valves had ever been repacked.

The licensee evaluated the traces for the eight MOVs that did not have the new Argo packing and noted that the spikes existed in three of these valves. The licensee concluded that if the value of the spike exceeded 50 percent of the TST value then the operability of the valve needed to be evaluated. The licensee determined that the Unit 3 LPSI miniflow isolation Valve SIA-669 had a spike of about 55 percent of the TST value. The licensee determined that the packing load trended down during maintenance intervals and there was not an operability concern with Valve SIA-669.

The inspector reviewed the licensee's transportability evaluation and agreed with the licensee's assessment that there was not an immediate operability concern with any other MOVs.

7.2.6 Corrective Actions

The licensee planned to repack the eight valves that had not been packed with the low resistance Argo packing in the next available outage. The licensee also agreed to trend the breakaway torque on the valves with the old packing and a sample of the new Argo packing to evaluate future performance.

At the exit meeting, the licensee agreed to evaluate what additional tools could be provided to technicians performing diagnostic trace reviews to help them

identify anomalies in the traces. The inspector will review the licensee's corrective actions in the response to the notice of violation.

8 FOLLOWUP - ENGINEERING/TECHNICAL SUPPORT (92903)

8.1 Unresolved Item 528/9431-01 (OPEN): Letdown Isolation Valve Would Not Close

In Inspection Report (IR) 50-528/94-31, the inspector identified concerns regarding the licensee's evaluation and resolution of significant seat leakage past the Unit 1 letdown isolation Valve CHB-UV-515. The valve had initially been identified as leaking at approximately 40 gpm when closed in December 1992 and had not been repaired when the inspector observed a deficiency tag on the control room switch associated with Valve CHB-UV-515 in September 1994. As noted in IR 50-528/94-31, the inspector identified that the licensee had not evaluated the degraded condition on the system operability in December 1992 and, when an evaluation was performed in October 1994, failed to consider all appropriate design basis.

At the time of the exit meeting for IR 528/94-31, the licensee planned to perform diagnostic testing of Valve CHB-UV-515 during the refueling outage scheduled to begin in April 1995. In addition, the licensee had initiated corrective actions to address weaknesses in the operability evaluation process.

8.1.1 Review of Outage Maintenance on Letdown Isolation Valves

Valve CHB-UV-515 is the B train air-to-open, spring to close, 2" globe valve located on the reactor coolant system letdown line to the chemical and volume control system (CH), located inside containment upstream of the regenerative heat exchanger. It receives close signals on high regenerative heat exchanger outlet temperature and a SIAS. Two similar valves, CHA-UV-516 and CHB-UV-523, are located downstream and provide inside and outside containment isolation respectively.

During the Unit 1 refueling outage, the licensee performed diagnostic testing on Valve CHB-UV-515. The licensee determined that the "bench set" of the actuator was not providing adequate seating force to ensure that the valve would remain closed against reactor coolant system operating pressure. The bench set determines the amount of spring pressure to close and seat the valve. Although the bench set for Valve CHB-UV-515 was below the values specified for the actuator, the licensee determined that even set at the appropriate values, the valve would have leaked if called on to close against a design basis differential pressures equivalent to the reactor coolant system relief valve settings.

The deficient seating force was determined to also apply to Valves CHA-UV-516 and CHB-UV-523. The licensee took action to evaluate the deficiency in accordance with the operability determination process for the letdown isolation valves in the operating units, identify the cause of the deficient design, and perform repairs on the letdown isolation valves in Unit 1. The inspector reviewed the operability determination and discussed the repairs with the licensee.

8.1.2 Potential Generic Issue

The licensee discussed the finding regarding low bench set with the vendor of the actuator, Fisher Controls. The vendor determined that the valve actuator had not been appropriately sized for the application. The vendor found that they had not properly accounted for valve packing friction in the sizing of the actuator. At one point in their design process, they stopped using low friction teflon packing material and switched to higher friction graphite packing material. However, for some period after the switch, they had not factored the higher friction into the actuator sizing. The vendor determined that this error was applicable to all of the letdown isolation valves in all three Palo Verde units.

NRC Information Notice (IN) 88-94, "Potentially Undersized Valve Actuators," dated December 2, 1988, discussed the failure of the Fisher Controls to consider packing friction in valve actuators. IN 88-94 concluded that valve actuators shipped after January 1, 1977, had appropriately accounted for valve packing friction. The licensee stated that their initial review of IN 88-94 determined that applicable valves had all been shipped after January 1, 1977, and in the case of the letdown isolation valves, had been shipped in 1978 and 1979.

The discovery that the letdown isolation valve actuators were not properly sized indicates that the conclusions in IN 88-94 may not have completely accounted for all undersized actuators. At the end of the inspection period, the licensee was communicating with the vendor and planned to perform an audit. Preliminarily, it appeared that valve actuators ordered before January 1, 1977, and subsequently shipped, may have not been appropriately sized.

8.1.3 Valve Actuator Repairs

The licensee repaired the letdown isolation valves by providing a stronger actuator spring, which allowed a greater bench set. In communication with the vendor, they concluded that other valve components did not need to be replaced. Subsequently, the licensee determined that the actuator handwheel could not support the stronger spring. As a result, the licensee performed a safety evaluation and determined that the handwheel was not necessary for the valve design functions.

The licensee performed operability determinations for the Unit 2 and 3 letdown isolation valves. They determined that it was necessary for two valves to close to isolate the letdown line against design basis differential pressure. They reviewed the design basis events for the letdown line valves and determined that two valves would be available in all cases to provide letdown isolation. The inspector reviewed the operability evaluation and determined that the evaluation appropriately addressed the design conditions identified.

The inspector identified weaknesses in the operability evaluations performed prior to November 1994 and included this as an unresolved item. In their evaluation in April 1995, the licensee determined that the letdown isolation valves inside containment provided high energy line break protection and that this had not been previously reviewed. The licensee planned to perform a self-

assessment of the operability review process as applied to the letdown isolation valves. The inspector will review the assessment in a future inspection report.

8.2 <u>(Closed) Unresolved Item 50-528/94-26-04: Equipment Qualification of Turbine Driven Auxiliary Feedwater Pump Main Steam Supply Bypass Valves</u>

This unresolved item involved an EQ issue with the solenoid coil of the main steam supply bypass Valves MSSBVs, SG-134A and 138A. The MSSBVs are solenoid operated valves, normally de-energized, and are subjected to high process fluid temperatures of 600 degrees F.

In August 1994 the licensee determined that the coils had exceeded the qualified life of 20 years since the actual field temperature of the coil was about 150 degrees F more than the temperature assumed in the qualification binder for the coil (the calculated EQ life was based on 204 degrees F and the actual field temperature was 350 degrees F). Based on a coil temperature of 350 degrees F, the qualified life was reduced to 18 days. The inspector was concerned that the licensee was collecting data for over a year before they evaluated the impact to the plant. The inspector was also concerned about the rigor of the EQ evaluations since there had been several iterations of the EQ life of these solenoids.

8.2.1 Licensee's Evaluation

The licensee initiated a CRDR to address the inspector's concerns and to determine the most accurate EQ life of the MSSBV solenoid coils. The licensee's evaluation explained the history of the EQ issues associated with the MSSBVs and the basis for the various values for the EQ life of the valve coils.

The licensee determined that the calculated EQ life of 18 days used the most limiting activation energy for all the components in the MSSBV solenoid coil. The licensee contacted the solenoid valve vendor and determined that the most critical component of the solenoid was the polymide insulation on the coil wires. The engineers used the activation energy and aging information for the polymide insulation and the service temperature of 350 degrees F and calculated an EQ life of 9.3 years. The licensee subsequently updated the EQ binder for the MSSBVs and the PM frequency in the PM basis database to reflect the 9.3 year EQ life.

The inspector reviewed the licensee's evaluation and had the following observations:

- The licensee performed a thorough evaluation and had a good engineering basis to support an EQ life of 9.3 years for the MSSBV solenoid coil.

- EQ engineering collected temperature data on the MSSBVs for almost a year that clearly showed in service coil temperatures that were significantly higher than the temperature used in the qualification report and did not perform a relatively simple calculation to determine the qualified life based on these temperatures.

- The engineer was collecting data and did not have an acceptance criteria, or upper threshold, at which point an evaluation would be conducted to determine if there may be a qualification issue.

The inspector noted that the licensee recently implemented an "attributes of engineering excellence" program to address the timely and complete resolution of engineering issues. The inspector concluded that application of these principles by all levels of the engineering organization would help prevent two year long evaluations similar to the MSSBVs.

The inspector also noted that nuclear assurance engineering (NAE) performed an audit in December 1994 and reviewed the adequacy of the licensee's overall thermal monitoring program.

8.2.2 Thermal Monitoring Program

The NAE audit team noted that the licensee committed to have a thermal monitoring program and that a formal program did not exist. The audit team found that a 1991 audit had identified the same weakness and the corrective actions from that audit were ineffective. The audit team also identified that formal EQ training for engineering, maintenance, and operations personnel was significantly below the industry average. The audit team issued CRDR 9-4-Q184 to the EQ group to develop and implement a formal thermal monitoring program.

The inspector reviewed EQ engineering's response to CRDR 9-4-Q184 and discussed the proposed implementation of the thermal monitoring program with the EQ Department Leader. The inspector noted that the EQ group reviewed the various EQ zones in the plant and determined what areas were susceptible to process fluid heating and then identified the EQ components in these areas with qualified lives less than 15 years. The licensee determined that the majority of these components were in the main steam support structure (MSSS) around the main steam and main feedwater lines.

The licensee was in the process of determining the components to be monitored in these areas and then selecting a temperature recording device to install on these components. The monitoring instruments were scheduled to be installed by the end of 1995.

The inspector conducted a walkdown of the auxiliary building and the MSSS to determine where the process fluid could possibly increase the temperature of EQ components. The inspector agreed with the licensee's assessment that the areas of concern were primarily in the MSSS. The inspector concluded that the licensee's initial evaluation to determine the scope of the thermal monitoring program was appropriate.

The inspector also took field temperature readings of the atmosphere dump valve (ADV), main steam isolation valve (MSIV), and the feedwater isolation valve (FWIV) lower limit switches and compared them to the temperatures used in the qualified life calculation. The inspector noted that the qualified life of the

MSIVs and ADVs was based on a service temperature of 150 degrees and the actual temperature in the field was about 150 degrees. The inspector noted that the licensee had changed the service temperature for the MSIV and ADV lower limit switches in the EQ binder from 130 to 150 degrees in January 1994 based on measured field temperatures of 150 degrees. The licensee subsequently changed the EQ life of the switches from 149 to 58 months.

The inspector noted that field temperature readings on the FWIV lower limit switches were reading around 150 degrees and that the qualified life was still based on a service temperature of 130 degrees. The inspector asked the licensee if they had been monitoring the temperatures of the FWIVs limit switches and evaluated the impact of the higher temperatures on the life of the switches.

The licensee informed the inspector that an EQ engineer had been monitoring the temperature of all the limit switches in the MSSS once a month for the last five months and had also observed some temperatures as high as 150 degrees on the lower FWIV limit switches. The inspector asked the EQ section leader what field temperature would trigger an evaluation of the limit switch qualified life and how long they planned to collect the temperature data before an initial evaluation was performed.

The EQ section leader informed the inspector that the EQ engineer did not suspect a problem with the existing temperatures of the lower FWIV limit switches because the temperatures were not significantly greater than the assumed value. Additionally, the EQ engineer was aware of conservatism in the activation energy and post accident environment used in the qualification of the limit switches that would mitigate the small increase in service temperature. The inspector was concerned that the engineer had not done any calculations or modeling of the field conditions to substantiate his engineering judgement used to arrive at this conclusion.

The licensee subsequently performed an assessment of the temperature data and determined that there was not a qualification concern if the average FWIV limit switch temperature remained less than 140 degrees. The engineer had recorded an average FWIV lower limit switch temperature of 137 degrees. This number was then adjusted to account for a 2 month outage time with a temperature of 80 degrees every 18 months which reduced the average temperature to 133 degrees. The inspector reviewed the evaluation and agreed with the licensee's conclusion that there was not an immediate qualification concern with the FWIV lower limit switches.

8.2.3 Conclusion

The inspector concluded that the licensee should have bounded the temperatures at which a more detailed review of the qualified life of the components in the MSSS was required. The inspector noted that relying exclusively on engineering judgement was not consistent with the attribute of engineering excellence that requires a "rigorous application of engineering principles". The stated value of this attribute is "the complete and demonstrated resolution of an issue with sufficient technical justification, graphs, calculations and associated analysis

techniques so the issue is 'engineered' to completion and not just 'justified' to a conclusion. This approach allows for engineering judgement; however, it requires an in-depth application of calculations, cost benefit, and risk analysis."

The inspector discussed this apparent over-reliance on engineering judgement during the collection of the temperature data with the EQ section leader who agreed with the inspector. At the exit meeting, the Director of System Engineering stated that they would establish levels of temperature differences between measured in-service temperatures and the temperature used to qualify each critical component that would trigger the performance of various levels of evaluations prior to implementing the formal thermal monitoring program. The inspector concluded that these actions were appropriate.

ATTACHMENT 1

1 Persons Contacted

1.1 Arizona Public Service Company

*J. Bailey, Vice President, Nuclear Engineering
*S. Bauer, Acting Department Leader, Nuclear Regulatory Affairs
*S. Coppock, Engineering Supervisor, Maintenance Valve Services
*B. Eklund, Regulatory Consultant, Nuclear Regulatory Affairs
*D. Garchow, Director, Site Engineering
*W. Ide, Director, Operations
*J. Levine, Vice-President, Nuclear Production
R. Lucero, Department Leader, Electrical Maintenance
*D. Mauldin, Director, Maintenance
*J. Minnicks, Department Leader, Maintenance Valve Services
M. Muhs, Section Leader, System Engineering
M. Radspinner, Section Leader, Design Engineering
F. Riedel Department Leader, Operations Unit 2
M. Salazar, Section Leader, Maintenance Valve Services
*C. Seaman, Director, Nuclear Assurance
D. Smith, Department Leader, Operations Unit 1
B. Simpson, Vice-President, Nuclear Support
*W. Stewart, Executive Vice President, Nuclear
*R. Stroud, Regulatory Consultant, Nuclear Regulatory Affairs
J. Taylor, Department Leader, Operations Unit 3
*P. Wiley, Department Leader, Operations

1.2 NRC Personnel

*K. Johnston, Senior Resident Inspector
*D. Garcia, Resident Inspector
J. Kramer, Resident Inspector
*A. MacDougall, Resident Inspector

1.3 Others

*J. Draper, Site Representative, Southern California Edison
*F. Gowers, Site Representative, El Paso Electric
*R. Henry, Site Representative, Salt River Project

*Denotes those present at the exit interview meeting held on May 19, 1995.

The inspector also held discussions with and observed the actions of other members of the licensee's staff during the course of the inspection.

2 EXIT MEETING

An exit meeting was conducted on May 19, 1995. 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.

ATTACHMENT 2

1 LIST OF ACRONYMS

ADV	atmospheric dump valve
APS	Arizona Public Service
ATTN:	attention
CS	containment spray system
CFR	Code of Federal Regulation
CRDL	control room deficiency log
CRDR	condition report/disposition request
CW	circulating water system
ECP	Employee Concerns program
EQ	equipment qualification
FWIV	feedwater isolation valve
GL	Generic Letter
I&C	instrumentation and controls
IN	Information Notice
LER	Licensee Event Report
LOCA	loss of coolant accident
LPSI	low pressure safety injection system
MITR	management issues tracking and resolution program
MOV	motor operated valve
MSSBV	main steam supply bypass valve
MSSS	main steam support structure
MSIV	main steam isolation valve
NA	not applicable
NAE	Nuclear Assurance Engineering
NRC	Nuclear Regulatory Commission
PM	preventive maintenance
ppb	parts per billion
PRA	probabilistic risk assessment
RAS	recirculation actuation signal
RCS	reactor coolant system
RRS	rotating rising stem
RWT	refueling water tank
SIAS	safety injection actuation signal
STA	shift technical advisor
TAPA	temporarily approved procedure action
TQS	torque switch
TST	torque switch trip
TS	Technical Specification
VSDS	valve survey data sheet
WO	work order