U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-528/92-31, 50-529/92-31, and 50-530/92-31

Docket Nos. 50-528, 50-529, and 50-530

License Nos. NPF-41, NPF-51, and NPF-74

Licensee Arizona Public Service Company
P. O. Box 53999, Station 9012
Phoenix, AZ 85072-3999

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

Inspection Conducted August 25 through September 30, 1992

Inspectors J. Sloan, Senior Resident Inspector
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Approved By H. Wong, Chief 11/3/92
Reactor Projects Section 2 Date Signed

Inspection Summary:

Inspection on August 25 through September 30, 1992 (Report Numbers 50-528/92-31, 50-529/92-31, and 50-530/92-31)

Areas Inspected: Routine, onsite, regular and backshift inspection by the three resident inspectors, and one Region V inspector. Areas inspected included:

- review of plant activities
- engineered safety feature system walkdowns - Unit 2
- surveillance testing - Units 1, 2, and 3
- plant maintenance - Units 1, 2, and 3
- reactor trip due to turbine trip - Unit 1
- auxiliary building flooding - Unit 2
- class 1E 4160 volt breaker failure - Unit 3
- large reactor coolant system (RCS) spill in containment with refueling cavity filled - Unit 3
- spray pond pump rebaselining - Unit 3
- licensed operator requalification - Units 1, 2, and 3
- followup on previously identified items - Units 1, 2, and 3
- review of licensee event reports (LER) - Units 1, 2, and 3

During this inspection the following Inspection Procedures were utilized: 41500, 60705, 60710, 61726, 62703, 71707, 71710, 92700, 92701, and 93702.

Results: Of the 12 areas inspected, one violation was identified involving the failure to follow procedures and respond to a plant alarm which indicated a high level in an auxiliary building sump.

General Conclusions and Specific Findings:

Significant Safety Matters: None

Violations: One violation - Unit 2

Deviations: None

Open Items: Four new items were opened, 18 items were closed, and two items were left open.

Strengths Noted: The investigation of the Magne-blast breaker failure to close, and the investigation of the Unit 1 reactor trip resulted in a good understanding of the causes of these problems.

Weaknesses Noted: Several examples of workers not meeting their individual responsibilities were observed, including an event in Unit 3 which caused a bubble of nitrogen in a safety injection tank to be released to the refueling cavity and caused a significant spill in containment. These events underscore the need for continued emphasis on attention to detail by workers.

DETAILS

1. Persons Contacted

The below listed technical and supervisory personnel were among those contacted:

Arizona Public Service (APS)

*R. Adney,	Plant Manager, Unit 3
J. Albers,	Manager, Operations Radiation Protection
*R. Boquot,	Supervisor, Quality Audits & Monitoring
*T. Bradish,	Manager, Licensing and Compliance
*R. Flood,	Plant Manager, Unit 2
*R. Fountain,	Supervisor, Quality Audits & Monitoring
*R. Fullmer,	Manager, Quality Audits and Monitoring
*D. Gouge,	General Manager, Plant Support
S. Guthrie,	Director, Quality Assurance
K. Hamlin,	Director, Nuclear Safety
P. Hughes,	General Manager, Radiation Protection
W. Ide,	Plant Manager, Unit 1
D. Leech,	Supervisor, Quality Audits & Monitoring
J. Levine,	Vice President, Nuclear Power Production
D. Mauldin,	Director, Site Maintenance & Modifications
J. Napier,	Engineer, Compliance
G. Overbeck,	Director, Site Technical Support
*R. Roehler,	Supervisor, Compliance
C. Russo	Manager, Quality Control
*R. Schaller,	Assistant Plant Manager, Unit 1
G. Shanker,	Manager, Significant Operating Events Department
T. Shriver,	Assistant Plant Manager, Unit 2
R. Stevens,	Director, Nuclear Licensing

Site Representatives

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

Others

*T. Hillmer,	Consultant, Nuclear Safety

* Denotes personnel in attendance at the Exit meeting held with the NRC resident inspectors on September 30, 1992.

The inspectors also talked with other licensee and contractor personnel during the course of the inspection.

2. Review of Plant Activities - Units 1, 2, and 3 (61715 and 71707)

a. Unit 1

Unit 1 operated at essentially 100 percent power until September 28, 1992, when a reactor trip occurred (see paragraph 6). The unit ended the inspection period in Mode 3.

b. Unit 2

Unit 2 operated at essentially 100 percent power throughout the reporting period. Several problems with the Core Operating Limit Supervisory System (COLSS) required power reductions to comply with Technical Specifications.

c. Unit 3

Unit 3 operated uneventfully at essentially 100 percent power until August 31, 1992, when the "B" heater drain pump failed, forcing a slight power reduction. On September 1, 1992, the end-of-cycle power coastdown was initiated. Coastdown continued until September 18, when plant shutdown began. Mode 3 was entered on September 19, 1992, beginning the third refueling outage for Unit 3. Cooldown to Mode 5 was achieved on September 20, and Mode 6 was entered on September 25. On September 28, during motor operated valve testing, a safety injection tank was inadvertently vented to the reactor coolant system, causing a large wave in the refueling cavity that resulted in a significant spill in the containment building (see paragraph 9). Fuel offload began on September 30, 1992, and was in progress as the inspection period ended.

d. Plant Tour

The following plant areas at Units 1, 2, and 3 were toured by the inspector during the inspection:

- Auxiliary Building
- Control Building
- Diesel Generator Building
- Fuel Building
- Main Steam Support Structure
- Radwaste Building
- Technical Support Center
- Turbine Building
- Yard Area and Perimeter
- Containment Building

The following areas were observed during the tours:

(1) Operating Logs and Records - Records were reviewed against technical specifications and administrative control procedure requirements.

(2) Monitoring Instrumentation - Process instruments were observed for correlation between channels and for conformance with technical specifications requirements.

(3) Shift Staffing - Control room and shift staffing were observed for conformance with 10 CFR Part 50.54.(k), technical specifications, and administrative procedures.

(4) Equipment Lineups - Various valves and electrical breakers were verified to be in the position or condition required by technical specifications and administrative procedures for the applicable plant mode.

(5) Equipment Tagging - Selected equipment, for which tagging requests had been initiated, was observed to verify that tags were in place and the equipment was in the condition specified.

(6) General Plant Equipment Conditions - Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that could prevent the systems from fulfilling their functional requirements.

The inspector observed that none of the Unit 1 "B" emergency diesel generator (EDG) jacket water cooling crossheader flange bolts were completely engaged with the nuts, for both left and right header flanges. As a result of this observation, the licensee initiated Material Nonconformance Report (MNCR) 92-DG-1025 and determined that the condition was acceptable as is until the next Unit 1 refueling outage. The inspector noted that this is another example of incomplete thread engagement similar to those examples addressed in Violation 528/92-17-01. The inspector concluded that this condition was the result of a worker in the past not fulfilling his responsibility to ensure the fasteners were fully engaged, but that the licensee's response to this observation was adequate.

The inspector identified a screw missing from the housing for the electrical connection box for the Unit 3 "A" containment spray pump motor. The licensee initiated a work request to replace the screw. As there were several other fasteners in place, the inspector did not consider the missing screw a significant degradation. The licensee had previously identified some screws missing from the motor casing, which have not yet been replaced. The inspector concurred with the licensee's assessment that this condition was an example of workers not fulfilling their responsibility to ensure fasteners are all securely in place following maintenance.

During this period, the licensee observed leakage from the Unit 3 spent fuel pool leakoff detection system. About 250 ml of leakage was observed in a 48 hour period. The source of the water is not known, though analysis of the water revealed that

its boron concentration was approximately 2000 ppm, substantially less than the 4000 ppm of the spent fuel pool. This indicates that the water is from a source other than the spent fuel pool. The licensee is continuing to monitor the leakage. The inspector concluded that the licensee's actions were appropriate.

The inspector identified dual direction arrows on the handwheel for the Unit 3 valve SIA-HV-685, "A" LPSI pump discharge to shutdown cooling heat exchanger. Handwheel issues are discussed further in paragraph 12.b(1).

(7) Fire Protection - Fire fighting equipment and controls were observed for conformance with technical specifications and administrative procedures.

(8) Plant Chemistry - Chemical analysis results were reviewed for conformance with technical specifications and administrative control procedures.

(9) Security - Activities observed for conformance with regulatory requirements, implementation of the site security plan, and administrative procedures included vehicle and personnel access, and protected and vital area integrity.

(10) Plant Housekeeping - Plant conditions and material/equipment storage were observed to determine the general state of cleanliness and housekeeping.

(11) Radiation Protection Controls - Areas observed included control point operation, records of licensee's surveys within the radiological controlled areas, posting of radiation and high radiation areas, compliance with radiation exposure permits, personnel monitoring devices being properly worn, and personnel frisking practices.

On August 29, 1992, two Unit 1 electricians entered a high radiation area without proper dosimetry and without being authorized to enter high radiation areas by their radiation exposure permits. This issue is described in detail in Inspection Report 528/92-30 and is being mentioned here because it represents an example of workers failing to meet individual radworker responsibilities.

On September 25, 1992, a Unit 3 work control planner stepped across the Unit 2 Radiological Controlled Area (RCA) boundary with the intention of returning to the RCA without first being monitored using a personnel contamination monitor (PCM) or whole body frisk as required by step 3.7.1 of procedure 75AC-9RP01, Radiation Exposure and Access Control, revision 1.7. A radiation protection technician immediately stopped and questioned the worker. The individual frisked using the PCM,

met with RP at the RP "Island," and was questioned regarding a notebook which had been taken out of the RCA. The individual responded with the understanding that since the RCA entry did not include contaminated area entries, frisking of the notebook was not necessary. The licensee initiated Condition Report/Disposition Request (CRDR) 2-2-0305, coached the individual regarding RCA exit requirements, later barred the individual from the RCA, performed a contamination survey of the individual's work area which showed no contamination, and notified appropriate management personnel. Since the licensee's investigation was not complete by the end of the reporting period, this issue will be an Unresolved Item (529/92-31-01) to be furtner evaluated in a subsequent inspection report.

(12) Shift Turnover - Shift turnovers and special evolution briefings were observed for effectiveness and thoroughness.

No violations of NRC requirements or deviations were identified.

3. Engineered Safety Feature (ESF) System Walkdowns - Unit 1 (71710)

Selected engineered safety feature systems (and systems important to safety) were walked down by the inspector to confirm that the system was aligned in accordance with plant procedures. During this inspection period the inspectors walked down accessible portions of the following systems:

- Auxiliary Feedwater "A," "B," and "N"
- Essential Cooling "A"

No violations of NRC requirements or deviations were identified.

4. Surveillance Testing - Units 1, 2, and 3 (61726)

Selected surveillance tests required to be performed by the technical specifications were reviewed on a sampling basis to verify that: 1) The surveillance tests were correctly included on the facility schedule; 2) A technically adequate procedure existed for performance of the surveillance tests; 3) The surveillance tests had been performed at the frequency specified in the technical specifications; and 4) Test results satisfied acceptance criteria or were properly dispositioned.

Specifically, portions of the following surveillances were observed by the inspector during this inspection period:

Unit 1

Procedure	Description
73ST-1XI16,	"Section XI Valve Stroke Timing, Partial Stroke Exercise & Position Indication Verification - Mode 1 thru 6 FWIVs (Economizer)"

Unit 2

Procedure	Description
72ST-2RX03,	"DNBR/LHR/AZITILT/ASI With COLSS Out of Service"
74ST-9SI01,	"Safety Injection Tank Boron Surveillance Test"
77ST-2SB07,	"CPC Channel 'A' Functional Test"
77ST-2SB09,	"CPC Channel 'C' Functional Test"

Unit 3

Procedure	Description
43ST-3ZZ33,	"Mode 1 Surveillance Logs"

On September 2, 1992, during the performance of 43ST-3ZZ33, "Mode 1 Surveillance Logs," the licensee initially determined that Core Protection Calculator (CPC) channels "A" and "D" did not satisfy the acceptance criteria for Reactor Coolant System (RCS) flow rate, in that the CPC value was slightly greater than the mass flow rate calculated by Core Operating Limit Supervisory System (COLSS). At the time of the surveillance test, the unit was operating at approximately 92 percent power and CPC channel "C" was inoperable for unrelated maintenance. The reactor operator performing the surveillance test noted that the applicable COLSS parameter, NKTMFLOWC, was wavering slightly, and during a check a few minutes later, the CPC parameters were within the acceptance criterion.

Procedure 43ST-3ZZ33 directs the operators to declare the affected CPC inoperable if the CPC value is greater than the COLSS value. If this action were taken, operators would have to trip the reactor. However, the shift supervisor and reactor operator further monitored the parameters and determined that the average value of NKTMFLOWC was such that the acceptance criterion was satisfied and that CPC "A" and "D" remained operable. Immediate action was taken to adjust the CPC flow constants to provide greater margin. The inspector noted that the adjustments resulted in a very small change in the Departure from Nucleate Boiling Ratio (DNBR) margin and concluded that the magnitude of the CPC adjustments was not significant. The inspector further concluded that the licensee's actions were appropriate.

The inspector observed surveillance test 72ST-2RX03, "DNBR/LHR/AZITILT/ASI with COLSS Out of Service," on September 16, 1992, following a loss of COLSS. Technical Specifications required this surveillance to be completed within two hours of the loss of COLSS. Despite the time pressure and other operational duties, the inspector

noted that this surveillance was performed with the same attention to detail and thoroughness that the inspector normally observes during the performance of surveillance tests. The inspector concluded that this was appropriate.

No violations of NRC requirements or deviations were identified.

5. Plant Maintenance - Units 1, 2, and 3 (60710 and 62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance/quality control department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. The inspector verified that reportability for these activities was correct.

The inspector witnessed portions of the following maintenance activities:

Unit 1

- "D" reactor trip breaker preventive maintenance
- Troubleshoot "D" reactor trip breaker cubicle
- Crane operation near 13.8kV power line
- Barrier construction around 13.8kV power line
- Repair "B" emergency diesel generator 10R jerk pump

Unit 2

- Walkdown in containment to look for leaks
- Calibration of radiation monitor RU-153
- "B" essential cooling water heat exchanger tube repair
- Troubleshoot "A" reactor trip breaker
- Replace highway traffic director "A" cards and terminations for plant computer and core monitoring computers
- Calibration of "B" train containment spray header level transmitter and local indicator
- CEDM fan greasing
- CEDM fan stack and bolting inspection

Unit 3

- "C" reactor trip breaker preventive maintenance
- Troubleshoot "B" low pressure safety injection pump breaker
- Remove and replace "A" and "C" Class 1E batteries (DCP-PK-37)
- Reactor vessel head auxiliary equipment disassembly
- Core offload

a. On September 24, 1992, the inspector observed Unit 2 instrument and control (I&C) technicians calibrate the containment spray header "B" level transmitter and local meter in the Unit 2 containment under

work order 561511. The inspector noted that the work order did not provide instructions on how to isolate the instrument, attach the test equipment, calibrate the transmitter, adjust the transmitter, vent the transmitter, or adjust the local meter. The I&C supervisor indicated that the work order referenced procedures 36MT-9ZZ03 and 36MT-9ZZ13 which provided this generic information and that procedure 30DP-9MP01, "Conduct of Maintenance," identifies instrument calibration as a skill of the craft activity which does not require step by step instructions.

The inspector noted that procedure 36MT-9ZZ13 was canceled on March 18, 1992, and that procedure 36MT-9ZZ03, "Isolation, Calibration, and Restoration of Differential Pressure Instruments," did not specify a particular sequence of valve manipulations to isolate the transmitter, how to adjust the transmitter, how to vent the transmitter, or how to adjust the local meter. During the performance of the calibration, the inspector also noted that the technicians applied a test pressure which was expected to move the local meter indicator to the top end of the indicating scale but actually drove the indicator into the top stop before the technicians noted the indicator position. The inspector further noted that during the calibration of the local meter, the technicians did not observe complete stabilization of the local meter prior to obtaining and recording the transmitter output. As a result, the inspector noted minor drift in local meter indication after the technician walked away to obtain the transmitter output reading. While this drift was not enough to significantly impact the result of the calibration in this instance, the technician's technique which did not note this drift may not have noted more significant drift had it been present.

During the restoration the inspector noted that the technicians followed a different sequence of steps than that specified in the work order. The inspector concluded that the work order and referenced procedures did not provide a consistent level of detail of work instructions, and the techniques used by the technicians did not anticipate potential problems. The inspector further concluded that the weaknesses observed did not invalidate the calibration, but may cause potential calibration anomalies not to be identified. APS is evaluating the inspector's comments.

b. On September 24, 1992, the inspector observed heating, ventilation, and air conditioning (HVAC) technicians grease the bearings for the Control Element Drive Mechanism (CEDM) fans in the Unit 2 containment. The work order called for the workers to pump three cubic inches of grease into both zerk fittings for each fan which needed to be greased. The inspector questioned the two HVAC technicians on how the three cubic inches of grease was to be measured and got answers of 50 and 51 pumps of the grease gun. The HVAC supervisor and the system engineer stated that 54 pumps of the grease gun would provide three cubic inches of grease. The inspector concluded that while the difference between the expected

and actual amount of grease pumped into the bearings would not likely impact the CEDM fan operation, the work order provided inadequate instructions for the workers.

On August 25, 1992, the inspector observed electricians troubleshooting the failure of the "D" reactor trip breaker to close in Unit 1. During the troubleshooting the inspector observed one electrician's hand extend back behind the breaker in the cubicle very near the energized main power stabs for the breaker, and near control power terminals. Later, with the breaker removed from the still energized cubicle, the inspector noted the electrician attach test equipment to terminals using alligator clips which later popped off the terminal and landed on the floor of the cubicle. The inspector questioned whether these practices for troubleshooting in energized equipment was within the guidelines of maintenance expectations. The Unit 1 electrical maintenance supervisor and the electrician stated that work around energized equipment is expected, no specific guidelines exist regarding minimum clearances from energized contacts, the maintenance departments rely on the electrician's judgement regarding what and when protective material is to be used, and no specific guidelines existed regarding the use of test clips on energized equipment. The licensee responded by factoring the inspectors observations and questions into a Maintenance & Work Control Newsflash entitled "Energized Equipment Troubleshooting Expectations," dated September 17, 1992, which was being developed. This Newsflash identified management expectations for troubleshooting energized equipment including guidelines for test clips and the use of insulating gloves, mats, etc., for the protection of personnel and equipment. The Newsflash states that a procedure for work on energized equipment is also being developed. The inspector concluded that the Newsflash guidelines provide additional guidance which may prevent troubleshooting work practices from harming workers or equipment.

No violations of NRC requirements or deviations were identified.

6. Reactor Trip due to Turbine Trip - Unit 1 (93702)

On September 28, 1992, at 9:37 PM (MST), Unit 1 tripped from 100 percent power. Immediately prior to the trip, a momentary ground alarm was received on a non-Class 1E 125 volt DC panel which feeds part of the generator protective circuitry, and approximately 30 seconds later a sub-synchronous relay (SSR) lockout relay actuated, resulting in a turbine trip. The reactor tripped on high pressurizer pressure about 15 seconds after the turbine trip, with pressure peaking at 2383 psia. No pressurizer safety valves were challenged. All equipment functioned normally, although manual control on feedwater control was required for both steam generators. No Engineered Safety Features (ESF) actuations occurred, and the plant was stabilized in Mode 3. The inspector reviewed control room conditions, logs, and strip charts, and concluded that licensee response appeared to be appropriate.

The SSR is a device which protects the turbine when there are oscillations between the unit and the grid. However, no such oscillations were observed. It is not believed that a valid SSR condition existed. The SSR auxiliary relay actuated, initiating the lockout and turbine trip, although none of the SSR primary relays that are designed to trigger the auxiliary relays actuated. However, previous grounds on the 125 vdc bus have been experienced without significant impact on the protective circuitry.

Troubleshooting revealed that an electrician was soldering on an energized circuit in the "A" main transformer cooling control cabinet. The AC soldering gun was determined by subsequent testing to induce current in the circuit being soldered. The most probable cause of the turbine trip was determined to be an inadvertent trip of one SSR auxiliary relay caused by this induced current. The licensee immediately banned all soldering on energized equipment, added controls to all work on energized equipment, and began developing more detailed instructions regarding work on energized equipment. The licensee's investigation was not complete at the end of this reporting period. The Plant Review Board met on September 30, 1992, and approved restart. The inspector concluded that the licensee's immediate actions and restart decision were appropriate.

No violations of NRC requirements or deviations were identified.

7. Auxiliary Building Flooding - Unit 2 (61726 and 93702)

On September 3, 1992, at approximately 1:15 PM, (MST), while investigating an abnormal auxiliary building "Engineered Safety Features Sump Hi-Lo" alarm, an auxiliary operator discovered approximately two inches of water on the 40 foot level of the auxiliary building. Post Accident Sampling System surveillance testing was in progress when the alarm was received. An investigation revealed that valve RDN-HV-408, auxiliary building sumps to liquid radwaste holdup isolation valve, was shut and should have been open. RDN-HV-408 was immediately opened and the sumps were pumped to the liquid radwaste system. Decontamination efforts were begun promptly.

Approximately two hours earlier, a routinely received alarm (Non-Engineered Safety Features Sump Hi-Lo) was received and acknowledged. The alarm response procedure 42AL-2RK7C required RDN-HV-408 to be checked open. This was not done and subsequently the sump overflowed and flooded a portion of the auxiliary building.

Condition Report/Disposition Request (CRDR) 2-2-0280 was initiated to review the incident. The investigation was completed and approved by senior management on September 17, 1992, and determined that control room personnel had not properly followed the alarm response procedure. The control room primary and secondary operators were subsequently disciplined. The inspector concluded that this failure to follow the alarm response procedure is an apparent violation of Technical Specification 6.8.1 (Violation 529/92-31-02). The inspector further

concluded that the licensee's immediate response upon discovering the flooding, and the CRDR investigation appeared appropriate.

One violation of NRC requirements was identified.

8. Class 1E 4160 Volt Breaker Failure - Unit 3 (62703 and 92700)

During surveillance testing on September 1, 1992, the Unit 3 "B" Low Pressure Safety Injection (LPSI) pump failed to start due to the breaker racking mechanism cam not being in the proper position. The spring-return-to-normal handle was not fully upright, causing a vee-notch in the elevator mechanism to be too low. The GE Magne-blast Type AM-4.16-250 breaker was found to be properly positioned in the breaker cubicle, though it appeared to be racked up beyond the fully racked position because the roller on the positive interlock shaft was sitting too high in the vee-notch. The incorrectly positioned notch forced the roller out slightly, causing the positive interlock shaft to rotate slightly, moving an arm which pushes the button on the top of one of two ganged switches in the closing circuit. The arm gap (distance from the arm to the top of the switch housing) was found to be 126 mils, significantly greater than the 1/32 inch (approximately 31 mils) criteria in the initial breaker installation procedure. The positive interlock shaft interacts with the breaker cubicle to prevent the breaker from closing unless it is racked in. The gap was such that the contact in the upper (charging spring motor) switch could barely close, and the contact in the lower (closing circuit) switch was not closed. Subsequent testing indicated that the contacts are closed when the arm gap is less than approximately 124 mils. Since the pump had been successfully run twice since the breaker was last racked up on August 11, 1992, apparently vibration or shock was sufficient to jar the shaft and open the contacts after the two successful breaker operations. The licensee determined that arcing had occurred in the charging spring motor switch, melting the switch such that its button would not travel sufficiently to close the contact in the closing circuit switch. This failure condition occurred without any indication to operators.

Prior to this event, on August 19, 1992, but after racking the breaker up on August 19, the licensee revised procedure 32MT-9ZZ34, "Maintenance of Medium Voltage Circuit Breakers Type AM-4.16-250," to require that the roller be verified to be in the center of the vee, with at least 1/16 inch between the roller and the bottom of the vee. This change was made to incorporate vendor guidance.

The licensee initiated inspections of all other safety-related 4160 volt GE Magne-blast breakers in all three units. One other breaker in Unit 3 was identified with a gap slightly greater than 35 mils, and one breaker in Unit 1 was found with a gap of 125 mils. The contact continuity for the Unit 1 breaker was not determined during the as-found examination by the licensee, though when the gap was reset to the as-found measurement, the charging spring motor contact was closed and the closing circuit contact was open, the same condition found in the Unit 3 "B" LPSI breaker. The licensee determined that the racking mechanism handle of

the Unit 1 breaker, which is linked to the cam with the vee notches, was not in the proper position due to mechanical interference. When the handle was placed in the proper position, the roller was centered properly in the vee notch and the gap was restored to within acceptable limits. Breaker inspections are still in progress.

The licensee determined that the root cause of the failure was inadequate procedural instructions. This was corrected in the August 19, 1992, revision to 32MT-9ZZ34, as described above.

The inspector concluded that the licensee conducted a thorough root cause of failure evaluation and initiated appropriate corrective actions.

No violations of NRC requirements or deviations were identified.

9. Large Reactor Coolant System (RCS) Spill in Containment with Refueling Cavity Filled - Unit 3 (71707 and 93702)

On September 28, 1992, at 10:54 PM (MST), during motor operated valve testing of the safety injection tank (SIT) "2B" outlet valve, residual nitrogen pressure in the SIT was inadvertently vented to the RCS, causing a large wave in the refueling cavity. The wave splashed over the sides of the cavity, resulting in an estimated 1500 gallon spill, contaminating large areas of all levels of the containment building from the 140' level down. No personnel were contaminated by the spill, and the equipment hatch was closed at the time of the event. All work in containment was stopped and personnel were evacuated from containment. The SIT vent valves were subsequently opened and caution tagged to indicate that they should be open before opening SIT outlet valves. The licensee initiated a Category 3 investigation (Condition Report/ Disposition Request 3-2-0346) to determine the cause and to identify appropriate corrective actions. Engineering personnel conducted walkdowns of containment to determine the impact of the spill on equipment, and decontamination efforts were initiated. The inspector will review the conclusions of the licensee's investigation upon completion (Unresolved Item 530/92-31-03). The inspector concluded that the licensee's initial response to the event was appropriate.

No violations of NRC requirements or deviations were identified.

10. Spray Pond Pump Rebaselining - Unit 3 (92700)

On September 10, 1992, the Unit 3 "B" Spray Pond pump, SPB-P01, failed its quarterly surveillance test due to low differential pressure. The licensee declared the pump inoperable and initiated actions to validate the test results, including recalibrating the instrumentation used during the surveillance test. All instrumentation was found to be acceptable, and the test results were validated. No changes had been observed in performance monitoring for this pump for the past three years. The licensee declined to explain the current change, but noted that the instrumentation had been calibrated since the previous test performance.

The inspector reviewed Engineering Evaluation Request (EER) 92-PV-015, which documents the licensee's justification for rebaselining the pump per American Society of Mechanical Engineers (ASME) Section XI Articles IWP-3112 and IWP-3230. The inspector noted that Article IWP-3112 allows establishing new reference values with documented justification when previous operation was satisfactory. The pump was rebaselined based on the previous (satisfactory) pump performance, which had been just above the alert low limit. The new reference point, 53.36 psid, is about the average of 14 quarterly tests performed since 1989, but is still greater than 4 of the 5 other spray pond pumps. The old reference point was 56.59 psid. The current test result (50.35 psid) is above the alert low level for the new reference point. The licensee analyzed the pump performance and determined it still to be acceptable.

The inspector noted that the licensee avoided having to determine a cause for the change in the most recent test data by electing to base the new reference value on previous tests only. Article IWP-3230 states that if deviations fall within the Required Action Range, the pump shall be declared inoperative and not returned to service until the cause of the deviation has been determined and the condition corrected.

The inspector concluded that the licensee's actions may not have been consistent with ASME Section XI requirements. This item will be considered unresolved pending determination of which articles of Section XI apply to these circumstances. (Unresolved Item 530/92-31-04)

No violations of NRC requirements or deviations were identified.

11. Licensed Operator Requalification - Units 1, 2, and 3 (41500)

The inspectors observed several simulator scenarios that were being evaluated by the licensee's training staff as part of the licensed operator requalification program. The inspectors noted that as a result of high failure rates during the initial evaluation weeks, on September 4, 1992, the licensee revised procedure 40DP-9AP05, "Emergency Operating Procedures Technical Guidelines." The revision indicates that the EOPs are written to stand alone, and that operator performance of EOP tasks is not to be judged on the basis of whether the implementing guidance was followed verbatim, but rather on adherence to the EOPs. Operators had previously been required to implement the guidance in 40DP-9AP05 or risk failure in the simulator scenarios. The revision, in effect, reduced the requirements on the operators during the final three weeks of the requalification cycle. Evaluators still required operators to adhere strictly to all applicable requirements. The revision appears to be appropriate. The inspector noted that licensee evaluators were expecting a higher level of procedural adherence to guidance procedures than expected previously.

The inspectors also noted some performance issues not identified by the evaluators during the scenarios or evaluation briefings:

- During some scenarios, no communications from the control room provided any indication to auxiliary operators that an event was in progress until the announcement of a Site Area Emergency. During the observed scenarios, no specific effort was made to apprise the auxiliary operators of the nature or status of the event.

- Crews were inconsistent in conducting periodic briefings to ensure everybody was aware of event status and mitigation/recovery efforts.

- During one scenario, two command and control deficiencies were observed. The Control Room Supervisor (CRS) directed the Primary Operator (PO) to calculate and perform boration due to a loss of Core Operating Limit Supervisory System (COLSS), then conducted a discussion on whether a downpower was necessary. Subsequent discussions between the CRS, Shift Supervisor, another operator, and the PO resulted in mixed signals to the PO and confusion as to whether the PO should begin the boration. In another instance, when the PO was uncertain about some breaker manipulations, the CRS directed him to "hold off." The PO subsequently resolved the uncertainty and proceeded with the manipulations without further communication with the CRS.

- The Control Room status board was not setup in the simulator. The secondary operator looked at the board only to find that the information needed was not available.

- The placard used to note the proper vernier dial position for the "A" auxiliary feedwater pump turbine speed setting was blank.

The inspectors concluded that there has been improvement in command, control, and communications, but that some discrepancies and informality persist. The inspectors further concluded that the evaluators maintained consistent high standards throughout the evaluations, though the revision to 40DP-9AP05 represented a significant reduction in the requirements placed on the operators.

No violations of NRC requirements or deviations were identified.

12. Followup on Previously Identified Items - Units 1, 2, and 3 (71707, 92701, and 92702)

    a. Unit 1

       (1) (Closed) Followup Item 528/91-25-07, Control of Motor Operated Valve Database - Units 1, 2, and 3 (92701)

       This item addresses informality in the control of motor operated valve (MOV) design data. To resolve problems the licensee experienced in keeping current a frequently changing database during MOV testing, the licensee had removed the design data from the controlled design document. The data was then maintained in a spreadsheet on a personal computer, with

information provided to appropriate personnel via an Engineering Evaluation Request (EER) as needed. This process was not proceduralized, and controls were not in place to ensure the integrity of the design data.

The licensee subsequently developed controls for this Interim Controlled Motor Operator Database (ICMODB). The inspector reviewed procedures 73PR-9ZZ04, "Valve Motor Operator Monitoring and Test Program," and 81DP-4C10, "Motor Operated Valve Design Basis Review and Thrust/Torque Calculation," which document the interim controls. The design information in the ICMODB is updated and issued periodically for each unit. Each entry of the database is compared with the approved design calculations for accuracy, and each page of the database is signed by the originator and an independent reviewer. Additionally, the cover of the EER is signed by the cognizant supervisor.

When the information in the ICMODB is finalized, as the result of the completion of MOV dynamic flow testing and static testing, the data will be included in the permanent MOV database, which conforms fully to the quality controls established for design output documents. The information in the ICMODB is not being considered final design information. If an MOV test reveals as-found information outside the limits identified in the ICMODB, procedure 73PR-9ZZ04 requires that an EER be initiated to determine the acceptable values, and requires that a Technical Specification Component Condition Record (TSCCR) be written and the valve not be returned to service until the EER is dispositioned and the condition resolved. For MOV information in the permanent database, MOVs found out of the acceptable limits are handled via the Material Nonconformance Report (MNCR) process.

The licensee stated that the procedure controls are still being improved, with an additional administrative control procedure expected to be issued in the next several weeks.

The inspector concluded that the licensee implemented adequate controls over the MOV design information. This item is closed.

(2) <u>(Open) Unresolved Item 529/92-22-01, Annunciator Jumpers - Units 1 and 2 (92701)</u>

This item involved a licensee program to interpret the work control and temporary modification procedures to permit the installation of temporary jumpers across inputs of defective field devices in the annunciator system without an engineering valuation or 10 CFR 50.59 evaluation. The licensee responded to the inspector's question regarding temporary modifications by stating that temporarily bypassing defective annunciator inputs is not worth the time nor expense needed to process a

temporary modification. The licensee decided to control the number of jumpers installed in the plant in a single system by requiring the approval of the Work Control Manager before the installation of each jumper, by documenting each jumper in the daily production meeting document, and by discussing the status of installed jumpers during the daily production meeting on a weekly basis. Engineering evaluated the use of these jumpers in EER 92-XI-021 which concluded that this program is acceptable provided it did not include SESS inputs because of their interpretation of Regulatory Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems."

The inspector observed the installation of several of these jumpers on July 24, 1992. One set of jumpers installed in the RK annunciator system cabinet under work order 549767 was found to be attached to test leads using alligator clips. The inspector questioned the use of these clips, when they were installed, and whether the use of unattended test leads attached with alligator clips was appropriate. The licensee investigated this and identified that these test leads were attached on May 21, 1992. The licensee removed them after the inspector questioned their use on July 24, 1992. On September 17, 1992, the licensee issued the Newsflash referred to in paragraph 5 regarding energized equipment troubleshooting which stated that alligator clip test leads are appropriate only during troubleshooting activities and are not to be left in place. The inspector concluded that this policy appeared appropriate.

The inspector noted that several emergency operating procedures (EOPs) specifically refer to annunciators not excluded from this program. Examples of this include section 1.1 of 42EP-2RO02, "Loss of Coolant Accident," where low pressurizer pressure and pressurizer low level alarms can be used to verify entry conditions to this procedure; and section 7.66 of 41EP-1RO06, "Loss of Offsite Power," where operators are required to follow the applicable alarm response procedure for any reactor coolant pump annunciator listed in this EOP step. In addition, in simulator scenarios the inspectors have noted that operators routinely use the annunciators for engineered safety features actuation system (ESFAS) status on control room board B05 to note actuation of specific engineered safety features. This EOP reliance on annunciators which may by bypassed by this jumper program without a 10 CFR 50.59 review or compensatory actions raises additional questions. This unresolved item will remain open pending resolution of these questions.

(3) (Closed) Followup Item 528/90-42-04, Emergency Diesel Generator Loading Calculation Adequacy (92701)

The NRC Electrical Distribution Functional Inspection team noted that the emergency diesel generator (EDG) load calculation, Calculation 13-EC-DG-200, Revision 4, "Diesel Generator Load Calculation," did not include transformer losses. The team also noted that the calculation indicated that for forced shutdown there was less than one percent margin between calculated load and EDG continuous rating. The licensee noted that the loading calculation was being revised during the inspection.

Subsequent to the inspection, the licensee completed a new EDG loading calculation, 13-EC-DG-200, Revision 6. The calculation showed a minimum of three percent margin between maximum calculated load and EDG continuous rating.

The inspector reviewed Calculation 13-EC-DG-200, Revision 6 and concluded that the calculation was adequate to demonstrate EDG design capability to carry required loads during operational events. Therefore, this item is closed.

b. Unit 2

(1) (Closed) Followup Item 529/91-35-02, Valve Handwheel 'OPEN' Direction Arrows Incorrect - Units 2 and 3 (71707 and 92701)

This item was opened to track corrective actions resulting from the identification of incorrect direction arrows on valve handwheels. The inspector reviewed Condition Report/Disposition Requests (CRDRs) 2-1-0130 and 2-2-0036 and determined that the licensee has completed work orders correcting the identified deficiencies. One action remaining in CRDR 2-2-0036 is for all direction arrows to be removed from handwheels before being issued from the warehouse. During this inspection period, the inspector identified another valve, 3-SIA-UV-685, which had dual direction arrows (see paragraph 2.D.(6)). The licensee initiated a work order to correct this condition. The licensee stated that operators do not rely on handwheel arrows, and that the licensee's intention is to correct such discrepancies when they are identified. The inspector concluded that discrepancies still exist but are not safety significant, and that the licensee's actions were appropriate. This item is closed on the basis of this review.

(2) (Closed) Unresolved Item 529/91-35-04, Scaffolding Deficiencies - Unit 2 (92701)

This item involved scaffolding which did not meet the clearance requirements of the licensee's scaffolding program, and the clearance was not addressed in Engineering Evaluation Request

(EER) 91-ZJ-024 which evaluated that scaffold. The weaknesses in the licensee's scaffold program documented in Inspection Report 529/92-10 have been addressed. Instruction Change Request (ICR) 23764 has been completed and revised procedure 30DP-9WP11, "Scaffolding Instruction," to require a completed engineering evaluation prior to the erection of scaffolding which does not meet the criteria of specification 13-CN-380. All engineers who perform engineering judgement evaluations of scaffolding have been trained on specification 13-CN-380 and the calculation it is based on, 13-CC-ZZ-308. This training addressed the management expectation for engineers to write an EER to evaluate whenever scaffolding will be supported by equipment other than the floor or deck grating. EER 92-ZZ-007 evaluated the fact that revision 2 of specification 13-CN-308 was not supported by calculation 13-CC-ZZ-308. This EER is closed and the results were incorporated into revision 5 of calculation 13-CC-ZZ-308 dated July 8, 1992, which documented the basis for revision 2 of specification 13-CN-308. The inspector concluded that while programmatic weaknesses were identified and corrected, the scaffolding identified was ultimately shown to meet safety requirements. These actions addressed all questions and concerns with scaffolding resulting from the inspector's initial observation. This unresolved item is closed.

c. Unit 3

(Closed) Followup Item 530/91-50-02, Steam Generator Low Pressure Reactor Trip Setpoint Shift - Unit 3 (92701)

This item addresses the licensee's response to unexplained shifts in the steam generator (SG) low pressure reactor trip and main steam isolation signal trip setpoints, which occurred in Unit 3 and in Unit 2. In response to the recurring condition in the Unit 2 channel "B" Plant Protection System (PPS), the licensee unsuccessfully attempted to identify the source of the voltage spike at the variable setpoint circuit cards. The licensee then determined that modifying the circuit, so that the voltage spikes do not affect the function of the circuit card, was a more reasonable and timely alternative to a significant multi-year engineering project to find an correct the cause. The licensee modified the variable setpoint circuit card for PPS channel "B" SG #1 low pressure. Additionally, ferrite beads were placed on the wiring for the cards for SG #1 and SG #2. The licensee bypassed the PPS parameters while monitoring the effectiveness of the modification. The infrequent voltage spike events resulted in a lengthy evaluation period. On August 28, 1992, Temporary Modification 2-92-SB-010 was approved, allowing the PPS to be declared operable with the circuit card modification. The inspector reviewed this Temporary Modification and found it to be in accordance with the licensee's modification program. The licensee separately evaluated the installation of the ferrite beads per 10 CFR 50.59 and determined

that the beads did not require a temporary modification. The beads were left in the circuit.

The licensee intends to continue to monitor the "B" PPS in Unit 2 to provide additional assurance that the modifications are effective. All similar cards in all PPS channels in all three units will then be similarly modified.

The inspector concluded that the licensee's actions were reasonable and appropriate, and that its planned corrective actions appear to be adequate. This item is closed.

No violations of NRC requirements or deviations were identified.

13. Review of Licensee Event Reports (LER) - Units 1, 2, and 3 (92700)

a. Through direct observations, discussion with licensee personnel, or review of the records, the following LERs were closed.

(1) Unit 1

91-02 Revision L1, "Diesel Generator Surveillance Performed while Unit Operating"

92-04 Revision L0 and L1, "MSSV and PSV Setpoints Out of Tolerance"

This item is related to LER 529/91-05-L0 which is being reviewed. No new issues have been raised by this LER. The generic issues raised by this event will be reviewed under LER 529/91-05-L0. This LER is closed.

92-05 Revision L0, "Technical Specification Action Missed While Containment Isolation Valve Inoperable"

92-06 Revision L0, "ESF Actuations Due To Radiation Monitor Failure"

92-07 Revision L0, "Inadvertent Safety Injection and Containment Isolation Actuations"

92-11 Revision L0, "Missed Technical Specification Action for Core Operating Limit Supervisory System (COLSS) Inoperable"

(2) Unit 2

91-01 Revision L0 and L1, "MSSV and PSV Setpoints Out of Tolerance"

92-02 Revision L0 and L1, "Unit 2 Reactor Trip with Loss of Power (LOP) ESFAS and Unit 3 LOP ESFAS"

92-03 Revision L0, "Spurious Fuel Building Essential Ventilation System Actuation"

92-04 Revision L0, "Unit 2 and 3 Loss of Power (LOP) ESFAS"

b. The following Unit 2 LER was reviewed and left open:

91-05 Revision L0, "Main Steam Safety Valve Setpoint Out of Tolerance"

This item is related to a Technical Specification change request which has been submitted to NRR for review. This review has raised several questions which are currently being evaluated. This item will remain open until NRR has completed their review of this Technical Specification change request.

No violations of NRC requirements or deviations were identified.

14. Exit Meeting (71707)

An exit meeting was held on September 30, 1992, with licensee management and the NRC resident inspectors during which the observations and conclusions in this report were generally discussed.

The licensee did not identify as proprietary any materials provided to or reviewed by the inspectors during the inspection.