ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-528/95-06
50-529/95-06
50-530/95-06

Licenses: NPF-41
NPF-51
NPF-74

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

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

Inspection At: Maricopa County, Arizona

Inspection Conducted: February 26 through April 8, 1995

Inspectors: K. Johnston, Senior Resident Inspector
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Approved: H. Wong, Chief, Reactor Projects Branch F — 5/10/95 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 design changes and modifications.

Results (Units 1, 2, and 3):

Operations

In general, the inspectors noted strong operations performance during routine control room observations. Operators demonstrated good communications, and operations supervision demonstrated good command and control (Section 3.2). The use of dedicated midloop operators was seen as a positive step towards enhancing midloop operations. The midloop operations crew in Unit 2 appeared to have a better understanding of the evolution and caught some errors made in the preparation for midloop. However, the crews did not place appropriate priority on adjusting an out of focus video camera on a midloop level sight-glass (Section 3.1).

Maintenance

Strong performance was noted in the performance of maintenance work in the areas of routine preventive maintenance (undervoltage relay switchgear, Section 4.4), emergent corrective maintenance (nuclear cooling water circuit temporary modification, Section 4.1), and quick response corrective maintenance (electro-hydraulic fluid leak, Section 4.2).

The testing of the standby gas turbine generator was poorly coordinated and controlled. A standby gas turbine generator tripped during testing when nonlicensed operators did not follow procedures (Section 5.1).

Electrical maintenance was slow to evaluate the implications of widespread testing failures of control element drive mechanism breakers on the operability of the same breakers in other units (Section 5.2).

Maintenance technicians and Nuclear Assurance personnel demonstrated a probing attitude in their followup of metal shavings found in the body of a Unit 2 auxiliary feedwater system valve (Section 7.1).

Engineering

Engineers demonstrated an improved safety conscience in the followup evaluations of degraded conditions. Excellent engineering was noted in the evaluation of fouling of the Unit 2 emergency diesel generator coolers. Engineers took appropriate steps to detail the extent of fouling before cleaning the coolers and took prompt action in evaluating the implications of the fouling on the operability of other emergency diesel generator coolers (Section 6.1).

Management Oversight

Overall, management appeared to address plant problems in an aggressive and thorough manner with little NRC involvement. An excellent example of this was the engineering response to the fouling of the Unit 2 emergency diesel generator coolers. Maintenance management was not as prompt in addressing the implication of control element drive mechanism breaker failures. It appeared that the focus was on breaker replacement and not component operability.

Summary of Inspection Findings:

One unresolved item (Unresolved Item 528/9506-01) was identified regarding the conditions which led to the licensee's request for a Notice of Enforcement Discretion concerning containment penetration overcurrent protection devices (Section 2.2).

One deviation (Deviation 528;529;530/9506-02) was identified concerning the failure of nonlicensed operators to follow procedures for the operation of the standby gas turbine generators (Section 5.1).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Acronyms

DETAILS

1 PLANT STATUS (71707)

1.1 Unit 1

Unit 1 began the inspection period at 100 percent power. On April 1, 1995, the unit was taken offline and entered Mode 4 in preparation for a refueling outage. The unit remained in Mode 4 to perform chemical cleaning of the steam generators and entered Mode 5 on April 3. On April 8, the unit entered Mode 6 and began a core offload. The unit ended the inspection period with the core offload in progress.

1.2 Unit 2

Unit 2 began the inspection period with the core offloaded to the spent fuel pool. On March 2, the licensee began reloading the core and the Unit entered Mode 6. On March 21, with the unit in Mode 5, Reactor Coolant Pump (RCP) 1A tripped on a ground fault found inside the motor junction box. The licensee determined that the fault was caused by a crack in the insulation of the motor terminal support plate and was not transportable to the other RCPs. On March 23 operators began a plant heatup using the other 3 RCPs. Repairs to RCP 1A were completed and the unit entered Mode 3 on March 25. The Unit was synchronized to the grid on March 30 and power was raised to 100 percent by April 4.

1.3 Unit 3

Unit 3 began the inspection period at 100 percent power and remained at essentially 100 percent power through the inspection period.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Reactor Vessel Head Inner O-Ring Seal Leaking - Unit 2

The licensee discovered that the Unit 2 reactor vessel head inner O-ring seal was leaking when the reactor coolant system (RCS) was repressurized during mode transitions following the refueling outage. A pressure indicator from the annulus between the inner and outer O-ring seals indicated RCS pressure. The annulus area was depressurized twice, each time returning to RCS pressure.

The licensee performed an inspection of the head area prior to entering Mode 2 and found no visible signs of outer seal leakage. In addition, the leak past the inner O-ring was quantified as approximately 0.005 gallons per minute or 7 gallons per day. The licensee performed an evaluation which considered the consequences of operating at full power for the duration of a cycle with only the outer O-ring intact. The inspector reviewed the evaluation and found it to be thorough.

As a compensatory measure, the licensee implemented a control room alarm which would detect any pressure reduction in the annulus between the two O-rings. This would provide indication of a leak past the outer O-ring which was greater than the leak past the inner O-ring. The alarm would be very sensitive to outer O-ring leakage, provided the leakage past the inner O-ring remained as small as had been initially determined. The licensee also indicated the normal means of detecting RCS leakage could also be used to possibly identify a leaking outer O-ring seal.

The licensee expected that the leak could seal itself as the unit proceeded to full power. The O-rings have a thin silver layer designed to improve the sealing surface as temperature increases. The licensee had initially planned to drain the annulus 1 week after the unit had returned to full power to see if the leak had sealed. These plans were cancelled by the licensee based on a vendor recommendation. The vendor was concerned that another pressure cycle on the seal could degrade the seal. The inspector found the licensee's actions to be appropriate. The inspector will monitor the licensee's continuing evaluation of the inner O-ring leak throughout the Unit 2 fuel cycle.

2.2 Notice of Enforcement Discretion for Penetration Overcurrent Protection - Units 1, 2, and 3

On March 30, 1995, the licensee requested that the NRC grant two Notices of Enforcement Discretion (NOEDs): one for Units 2 and 3 Technical Specification (TS) 3.6.3, "Containment Isolation Valves," and one for Unit 1 TS 3.8.4 "Containment Penetration Conductor Overcurrent Protective Devices." The request was granted by the NRC Region IV office the same day.

Design engineering had determined that 34 containment electrical penetration circuits in each unit did not meet Regulatory Guide 1.63 and Institute of Electrical and Electronics Engineers Standard 317-1976. These standards required that two protective devices be installed in electrical circuits penetrating containment if the maximum fault current exceeds the thermal rating of the penetration. One protective device was considered adequate for those circuits in which the maximum fault current did not exceed the thermal rating of the penetration. Design engineering discovered during a design basis revalidation effort that errors had been made in the original design calculations for maximum fault currents. They determined that 34 containment penetrations which had been installed with only one protective device had recalculated maximum fault currents that exceeded the penetration ratings. Based on engineering's findings, the licensee concluded that these 34 containment penetration circuits were inoperable in each unit and entered a 72-hour action statement for TS 3.8.4.

To correct the condition, the licensee needed to modify the circuits by inserting an additional protective device. In most cases, the licensee could deenergize the circuit with the unit at full power, complying with the TS action statement, while the circuit was modified. However, the circuit for the nuclear cooling containment isolation Valve NCB-UV-403 could not be

deenergized at power since it would have made the isolation function of the valve inoperable. While TS 3.6.3 required that an inoperable containment isolation valve be closed within 4 hours, closing Valve NCB-UV-403 would have isolated cooling to critical containment heat loads including the RCP. The licensee was concerned that the modification could not be completed within 4 hours.

Unit 1 was planning to shut down on April 1 for its refueling outage. While the timing of the TS 3.8.4.1 action statement would have allowed for the unit to begin the shutdown within 72 hours, the licensee was planning a steam generator chemical cleaning operation which was to extend the time in Mode 4 beyond the action statement limits. The licensee requested that an additional 42 hours be added to the 30 hours allowed to transition from Mode 3 to Mode 5. This would allow the licensee to postpone most of the circuit modifications until the start of the outage.

The licensee planned to perform the necessary modifications in Units 2 and 3 with the units in Mode 1. To perform the modification on the circuits associated with Valve NCB-UV-403, the licensee anticipated that the modification could be expected to take more than the 4 hours allowed by TS 3.6.3.1. They requested a 12-hour extension to the out of service time.

The NRC approved both requests based on the minimal safety significance and the compensatory measures implemented by the licensee. The licensee was able to implement the Valve NCB-UV-403 circuit modifications within the original 4-hour allowed outage time (1.5 hrs in Unit 3 and 0.75 hrs in Unit 2). The time spent in Mode 4 in Unit 1 following its shutdown on April 1 did exceed the original allowed outage time, but was within the extended time granted in the NOED.

In the following week, Nuclear Assurance (NA) questioned the timing of the declaration by plant management that the 34 circuits were inoperable. The circuits were declared inoperable by plant management in a meeting that was conducted shortly after Unit 2 entered Mode 1. The NA evaluation had not been completed by the end of the inspection period and will be reviewed in a future inspection. Additionally, the inspectors will review the root cause for the inadequate protection for the containment electrical penetration circuits in a future inspection (Unresolved Item 528/9506-01).

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Draindown to Midloop - Unit 2

3.1.1 Review of Prerequisites

On March 17, following the completion of steam generator eddy current testing, Unit 2 operators began preparations to drain the RCS to midloop to facilitate the removal of steam generator nozzle dams. The inspector observed both preparations for midloop operations and the draining of the RCS below the top of the hot leg. One of the changes the licensee had implemented since the

problems noted by the inspectors during the Unit 3 midloop operations (NRC Inspection Report 50-528/94-38; 50-529/94-38; 50-530/94-38) was that a dedicated midloop crew (a senior reactor operator (SRO) and reactor operator (RO)) had been established to supplement the regular crew standing watch during reduced RCS inventory conditions. The inspector found this to be a positive change.

Prior to the start of the draindown, the inspector reviewed the prerequisites of Procedure 420P-2ZZ16, "RCS Drain Operations," to assess whether the prerequisites had been met. The procedure prerequisites required that operators calculate the volume of water which they anticipated would need to be drained. The inspector noted the RCS volume to be drained, calculated by operators, was approximately 30,000 gallons too large. The inspector raised this concern to the SRO in charge of midloop. The SRO indicated that he was aware of the calculation error and was in the process of correcting the calculated drain amount. The initial error was made when the calculation had included a volume of water in the steam generator tubes. Since the RCS had been previously drained, there was no volume of water in the steam generator tubes.

The inspector asked the SRO if he had identified other procedure discrepancies. The SRO indicated a step had been signed off indicating Procedure Appendices K and L were complete. However, one of the steps in Appendix K, involving the control room verification of a valve's position, had not been completed since the valve was deenergized for maintenance and had no indication. The inspector reviewed the appendices with the SRO and determined the components were in the desired position. The inspector concluded the safety significance of not completing appendices was low and that the discrepancy had been identified by operations prior to initiating the drain down.

The inspector informed plant management about the procedure discrepancies. The inspector emphasized his concern that operators are continuing to sign off procedure steps of the RCS drain procedure when the steps are not complete. This had been a significant weakness identified during the Unit 3 midloop operation. Subsequently, operations management directed a complete review of the RCS drain procedure prior to starting the draining operations and found no further discrepancies. The inspector determined the licensee actions were adequate.

3.1.2 Observation of Draindown to Midloop

On March 18, the inspector observed operators lower the RCS level from just below the reactor flange level, about 114 feet, to midloop. The inspector noted that the site shift manager (SSM) and a NA evaluator were present during the entire evolution and provided good oversight.

The inspector also noted that there was a dedicated midloop SRO and RO in direct control of the draindown evolution. These individuals received over

8 hours simulator training involving RCS draining evolutions and classroom training on the use of the RCS draindown procedure. The inspector noted that the midloop SRO and RO displayed good command and control by continually checking both the refueling water level indicating system and the reactor vessel level indicating system to determine the current RCS level during the entire draindown evolution. For example, when the RO noted a drop in cold leg temperature indicating that the temperature detector located at the top of the cold leg was uncovered, he subsequently verified that the indicated RCS level was just below the top of the cold leg.

Although the operators were very diligent in monitoring the indicated RCS level using the control board indication, the inspector noted that the operators did not place much emphasis on using the installed sightglass to determine RCS level.

The inspector noted that, approximately 2 hours after the operators had started the draindown, the camera used to monitor the sightglass level in the nonoperating loop was not focused and there was a cable behind the sightglass that made it difficult to read. The midloop SRO agreed with the inspector that the sightglass level was difficult to read and did not indicate that the camera would be focused. The inspector then asked the shift supervisor about the situation and again did not get a commitment to focus the camera. Finally, the inspector asked the SSM about the adequacy of the indication. The SSM discussed the situation with the shift supervisor and an individual was sent into containment to focus the camera.

Approximately 1/2 hour later, the inspector noted that the camera used to display the sightglass level was not working. The inspector did not sense any urgency from the midloop SRO or RO to restore the indication prior to lowering the level into the hot leg. The inspector discussed the situation with the SSM. The SSM stated that the sightglass was not required by the RCS drain procedure. The inspector noted to the SSM that Section 8.0 of the RCS drain procedure had a step to ensure that the camera was installed on the sightglass with visual indication in the control room. The procedure allowed this step to be waived only with the concurrence of the operations department leader. As a result, the licensee subsequently restored and properly focused the sightglass indication prior to lowering RCS level into the hot leg.

Based on the interaction with the control room operators, the inspector questioned whether the operators would have focused the camera providing sightglass indication prior to entering midloop. The inspector discussed this observation with the supervisor of the midloop operations team who stated that the control room operators were aware of the need to focus the sightglass camera. The inspector acknowledged this statement, but noted that the operators had not informed the inspector of this intention.

At the exit meeting, the Director of Operators stated that the operators should have placed more emphasis on using the sightglass indication and that the midloop team would be briefed on this event and the importance of using

all available indications, including the sightglass, during RCS draining evolutions. The inspector concluded that these actions were appropriate.

3.2 Control Room Observations - Units 1, 2, and 3

The inspector observed the operating crews in the control rooms and observed the following:

- In general, the command and control of the control room was consistent with the new operations standards. The CRS was observed to directly supervise and authorize the control board manipulation. Orders were acknowledged and some cases repeated. Operations on the control boards were announced prior to performing the intended action.

- The inspector observed several ROs reporting alarms to the CRS, who in turn acknowledged the ROs. The reason for the alarms was given.

- The inspector observed one CRS, who admonished and then gave guidance to one RO who had left his control boards without informing the CRS or the other RO to ensure proper coverage and turnover. He emphasized his primary duty was to monitor and control the plant and maintain logs.

- The inspector was directly challenged by operations personnel upon entry into the control room, which was appropriate since they were not familiar with the NRC inspector. Control room access was limited.

- The inspector reviewed several log entries; they appeared to be complete. In general, the log entries were very brief, with the question of "why" an action was taken not addressed in some cases. As an example, on Unit 2, the log noted that operators had a problem with placing Control Element Drive Mechanism (CEDM) 38 on the hold bus. In the next log entry, 2 minutes later, CEDM 38 was successfully transferred to the hold bus. No reason was given in the control room log. The inspector determined, in discussion with operators, that a bad card pin had been discovered and repaired.

In summary, the inspector observed that crew performance was strong.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 Nuclear Cooling Water Temporary Modification - Unit 3

On March 31, the inspector observed electrical maintenance install a temporary modification (t-mod) on the power supply to a nuclear cooling water containment isolation valve. The modification involved the installation of an additional fuse to provide fault current protection of the containment penetration (see Section 2.2). The t-mod was performed during a TS allowed outage time which had been extended to 12 hours by an NOED.

The inspector noted the technicians were familiar with the equipment and demonstrated good electrical safety. The technicians had the necessary equipment available to minimize the out-of-service time. The inspector noted good coordination between operations and maintenance. The inspector concluded that the licensee demonstrated a strong overall performance during the t-mod installation.

4.2 Electrohydraulic Control (EHC) Fluid Leak - Unit 1

On March 20, the licensee identified that an Unit 1 turbine control valve had developed a significant EHC oil leak. The control valve was already closed at the time and the unit was at 85 percent power with a feedwater heater string out of service. The EHC oil leak was large enough to have an impact on the oil sump level. Operators responded by dispatching personnel to stop the leak and replenish the sump and then began to shut down the plant. Mechanics were able to significantly reduce the leakage which had been coming from the solenoid control valve block on the turbine control valve. The loss of level to the EHC oil sump was terminated at a level very close to the net positive suction head limits of the EHC oil pumps. Had the leakage continued, it was likely that the turbine control and stop valves would have closed, resulting in a turbine trip.

The inspector observed that the temporary repairs used a large "C" clamp and several tie wraps. Within a few hours, the maintenance engineer was able to determine the likely source of the leak and took action to secure the leak. The inspector noted that maintenance personnel had responded promptly and taken appropriate measures to avoid a plant transient.

4.3 Boric Acid Makeup Pump Discharge Check Valve Failure - Unit 2

During the Unit 2 refueling outage, while troubleshooting an apparent low flow condition in Charging Pump E in Unit 2, operators discovered that the leakage past the Train A boric acid makeup pump discharge check valve (CHV-154). Mechanical maintenance investigated and discovered that the valve disc had separated from the stem and was laying in the flow stream. The associated stem, stem nut, and spherical bearing had apparently been washed downstream. The swing arm was intact.

The licensee did not find the stem, stem nut, and bearing. They evaluated the piping layout and concluded that the components could not have travelled to a location in the system that impacted system operability. The inspector reviewed the licensee's analysis and found it to be thorough. In addition, the inspector walked down the system and determined that the licensee's conclusions were reasonable.

The licensee initiated a root cause of failure analysis. At the end of the inspection period, the root cause of failure analysis was ongoing. It appeared that the stem, which was threaded into the disc and then welded into place, had fractured just above the weld. The weld was at a threaded portion of the stem. The fracture appeared to be as a result of high cycle fatigue.

The 3-inch check valve was manufactured by Borg Warner, and similarly designed valves are used in several locations in the plant. The licensee has inspected similar valves in their check valve inspection program, including all of the boric acid makeup pump discharge check valves, and have not identified similar failures. However, the licensee conceded that it would be difficult to identify cracking without performing destructive examination. The licensee reviewed industry history and discussed the failure with the manufacturer. The licensee did not identify similar failures in their discussions with the manufacturer or their review of industry history.

The inspector will follow the licensee's continuing root cause evaluation in a future inspection.

4.4 Undervoltage Relay Maintenance - Unit 1

The inspector observed the replacement of undervoltage relay of the Westinghouse Type DS-416 reactor trip switchgear. The maintenance was performed in accordance with Procedure 32MT-9SB03, "Maintenance of Westinghouse Type DS-416 Reactor Trip Switchgear," Revision 4. The inspector's observations are summarized below:

- Maintenance personnel were familiar with the work since the undervoltage relay was replaced every 18 months for each reactor trip breaker.
- Problems were presented to the system engineer for resolution prior to proceeding. In this case, the replacement undervoltage relay had different size wires for the undervoltage coil. The splices called for incorrect wire sizes for the connections. After resolution with the correct splices, the undervoltage coil was replaced.
- Performance of the maintenance procedure proceeded in an efficient and orderly manner. No discrepancies or deficiencies were noted in the performance. Both personnel appeared to be well qualified in performing the undervoltage relay replacement.
- Supervision was present periodically to ensure that the maintenance was proceeding acceptably.

In summary, the maintenance activity was performed in an efficient and orderly manner. The personnel appeared to be well qualified and had performed this particular maintenance many times. No discrepancies or deficiencies were noted in the performance of the undervoltage relay replacement.

4.5 Auxiliary Feedwater (AFW) Check Valve - Unit 2

During the Unit 2 refueling outage, inservice testing engineers, inspecting Unit 2 AFW Train B Check Valve AFB-V-024, found that they could not dislodge the disc by hand from the seat. They subsequently pressurized the upstream portion of the piping with demineralized water pressure, dislodging the check

valve disc from its seat. The pressure necessary to dislodge the check valve was not determined, but was reasoned to be less than the demineralized water header pressure of approximately 100 psig.

The licensee performed an evaluation to determine the impact of the stuck check valve on the operation of the system. The check valve was in AFW Train B downstream of the miniflow recirculation line. The licensee determined that, under design basis conditions, the AFW Train B motor-driven pump would have developed sufficient differential pressure to open the check valve in the as-found condition. Therefore, the licensee concluded that the system had not been inoperable. The inspector reviewed the analysis and found it to be thorough.

The licensee inspected the valve and found no apparent cause for the disc to have become lodged in the seat. The licensee reviewed their check valve inspection history and had not found any similar occurrences. They speculated that the check valve disc had become lodged during a recent check valve backflow leakage test involving the start of the opposite train pump. This would have seated the check valve with greater than 1600 psig on the downstream side and condensate storage tank head on the upstream side. The licensee speculated that the tapered seat of the valve became lodged enough so that it could not be pulled out by hand.

The inspector observed the valve prior to reassembly and observed portions of the reassembly. In addition, the inspector reviewed portions of the investigation procedure. The inspector found them to be acceptable.

5 SURVEILLANCE OBSERVATION (61726)

5.1 Testing of Gas Turbine Generator

5.1.1 Background

On March 9, 1995, the inspector observed the licensee perform a test of the GTGs, the source of power to the units during a station blackout. The inspector noted that, during the test, the test director demonstrated weak command and control and the Water Reclamation Facility (WRF) operator twice failed to follow procedures. The inspector informed plant management about the observations. Plant management indicated that their expectations for command and control and procedure usage were not met. The licensee held briefings the following day to emphasize their expectations and then continued testing of the GTGs.

5.1.2 Failure to Follow Procedures

Procedure 70TP-2GT02, Revision 0, "GTG Parallel Operation With Nonclass 1E Loads," Step 8.1.8.1, states, in part, to synchronize GTG 2 with GTG 1 in accordance with Procedure 550P-0GT02, "Gas Turbine Generator 2 Operating Instructions." As the WRF operator read aloud the prerequisites for paralleling the GTGs and entered the instruction portion of the procedure, the

inspector noted that several prerequisites were not satisfied. The inspector stopped the operator and questioned him about the prerequisites. An NA evaluator, who was observing, subsequently noted the WRF operator was in the wrong procedure. The WRF operator had used Procedure 550P-0GT01, "Gas Turbine Generator 1 Operating Instructions," instead of Procedure 550P-0GT02, "Gas Turbine Generator 2 Operating Instructions," to synchronize GTG 2 with GTG 1. The inspector intervened during the performance of the procedure before any switch manipulations had occurred.

During test restoration, the licensee prepared to parallel GTG 1 to offsite power. Procedure 70TP-2GT02, Revision 0, "GTG Parallel Operation With Nonclass 1E Loads," Step 8.1.11.1, states, in part, to complete Section 6.4 (offsite power restoration) of Procedure 550P-0GT01, "Gas Turbine Generator #1 Operating Instructions." The WRF operator skipped the step and continued with the procedure. In addition, the inspector noted that the test director allowed the procedure to continue although Step 8.1.11.1 was not performed.

The inspector noted that the test director was in communication with the control room and it appeared that GTG 1 was going to be paralleled to offsite power. The inspector noted that the speed control ISOCH/DROOP switch was in the ISOCH position. The inspector asked the test director if GTG 1 switches were in the correct alignment. The test director indicated that GTG 1 was not going to be paralleled with offsite power. Within 1 minute, the control room synchronized GTG 1 with offsite power. The GTG immediately began to pick up excessive load and tripped. After the GTG trip, the inspector reviewed Procedure 70TP-2GT02 with the WRF operator and determined that he skipped Step 8.1.11.1 and had not performed the GTG switch alignment.

The licensee described the quality assurance commitments for station blackout equipment in their Updated Final Safety Analysis Report. The commitments included that testing of this equipment, which includes the GTGs, be performed in accordance with instructions. The inspector concluded that the WRF operator had failed to follow testing instructions. This is a deviation from Updated Final Safety Analysis Report commitments (Deviation 528;529;530/9506-02). In addition, the inspector noted that the command and control of the test director was weak. The test director maintained a copy of the procedure, but did not ensure that it was followed. The test director did not maintain positive command and control of the work being performed according to the procedure and allowed the control room to unexpectedly parallel the GTG with offsite power.

5.1.3 Corrective Actions

The inspector discussed these observations with the Director of Operations and the SSM. Prior to continuing the testing the following day, licensee management discussed command and control expectations with the test director. On March 10, the licensee held a preevolution brief to emphasize their expectations on procedure usage and overall test conduct. In addition, the

licensee assigned the SSM to observe the performance of the remaining tests. The licensee initiated Condition Report/Disposition Request (CRDR) 9-5-0211 to evaluate the human performance errors.

The inspector noted that NA had performed a detailed evaluation of the testing conducted on May 9. The licensee found that WRF operators, which, with the exception of the GTGs, do not operate equipment important to plant safety, had not used detailed operating instructions and did not have high standards for procedure compliance. While they had been briefed on self-verification techniques, they had not been held to a consistent expectation. In addition, the licensee concluded that the procedure was unnecessarily complex. In response to the NA evaluation and the CRDR, the licensee initiated corrective action to:

- Emphasize to WRF operators the necessity of procedure compliance in conducting GTG operations and the use of self-verification techniques.
- Initiate the use of job performance measures in the training of WRF facility operators on the operation of the GTGs.
- Initiate changes to the GTG operations procedure to simplify and consolidate operation instructions.

5.1.4 Safety Significance

Although the GTGs are not safety-related equipment, they were installed as quality augmented equipment and are, therefore, classified as quality-related components. Their function is to provide a source of power to the units during a station blackout. The overload trip of the GTG when it was paralleled to the offsite grid in the wrong mode challenged GTG protective devices. The licensee determined that the GTG had not exceeded design limits prior to the trip.

5.2 <u>CEDM Breakers Failed Surveillance Testing - Unit 2</u>

On March 15, 1995, the licensee began testing Unit 2 CEDM breakers to satisfy the surveillance requirements of TS 4.8.4.1. Each of the 89 CEDMs has a set of four, ganged 120 VAC molded-case breakers which provide containment penetration overcurrent protection for the power supplied to the CEDM coils. Three of the breakers are rated at 10 amps with the remaining breaker rated 30 amps. Each breaker has one magnetic/hydraulic type trip mechanism which has both instantaneous and time-delayed trip characteristics.

The licensee found that the breakers were consistently failing the time-delay portion of the trip testing. On March 20 and 21, the inspector pursued the licensee's evaluations of the cause of the test failures and the implications of these failures on the Units 1 and 3 breakers. The inspector noted that the focus of the electrical maintenance department leader appeared to be on the

replacement of breakers and not the implications of the failures. The inspector noted that, as of March 21:

- The majority of breakers tested during the refueling outage (a sample of approximately 60 percent) had failed the 150 percent time delay test. The licensee suspected that a change in testing methodology explained the difference between testing results from previous tests. However, no comparison testing had been performed.

- The licensee had not obtained test data from the previous Unit 2 refueling outage to compare test results and to identify if the previous testing would highlight either precursors or trends of the failures.

- The licensee had not documented an evaluation of breaker operability for Units 1 and 3, nor had they initiated a CRDR. They indicated to the inspector that they were comfortable with the operability of the breakers in Units 1 and 3. The inspector questioned the quality of their review without having performed the reviews described above.

The inspector noted that previous surveillance tests had been performed using dc current at 300 percent of the breaker rating. These tests were performed every 18 months on each unit on a sample of 10 percent of the breakers. The licensee changed their testing methodology to have a time delay test at 150 percent and an instantaneous test at 1000 percent of breaker rating. These changes were made to more closely reflect the TS surveillance requirements.

As of March 21, the inspector questioned whether testing a sample of the failed breakers at 300 percent had been considered to support the licensee's theory that the failures were attributable to the test methodology. The licensee had not performed comparison testing and agreed that such a test would be appropriate.

All 89 Unit 2 CEDM breakers failed testing and were subsequently replaced. The licensee subsequently performed testing of a sample of the failed breakers at the 300 percent current level and the breakers consistently opened as designed. The licensee determined that, as the breakers aged, they became less reliable at the lower overcurrent conditions, but remained reliable at higher current. A set of breakers was sent to the manufacturer for additional evaluation.

The licensee concluded that the breakers would have tripped under any overcurrent condition which could have damaged the associated cable penetrating the containment. In addition, the breaker failures would not impact the safety function of the control element assemblies to trip. The inspector discussed these test results and the evaluation of operability with the licensee and determined that their evaluation was appropriate.

The inspector discussed the slow response by electrical maintenance to review the cause and operability aspects of this issue with the Maintenance Director. The inspector noted that, following the implementation of reengineering in August 1994 and the integration of engineering into the maintenance organization, the maintenance organization appears to have gained a greater responsibility for the review of operability and safety implications of degraded equipment. However, the inspector noted that the evaluation of the CEDM breaker test failures may indicate that the maintenance organization may not be consistently addressing safety reviews when fixing degraded equipment. The Maintenance Director agreed that the maintenance organization's performance in this area could be improved.

At the end of the inspection period, the licensee was preparing to perform the same surveillance testing on the Unit 1 CEDM breakers. The licensee did not intend to change their testing methodology and expected that they would need to replace the majority of Unit 1 CEDM breakers. Additionally, NA was performing an evaluation of the issue. The inspector will follow these issues during the course of routine inspection.

5.3 Main Steam Safety Valve Testing - Unit 1

On March 28 and 29, the inspector observed Unit 1 main steam safety valve testing, which utilized an assist device to open the valves for determining set pressure (Trevitest method). Procedure 73ST-9ZZ18, "Main Steam Safety Valve Online Set Pressure Verification," was used by licensee and vendor personnel to perform the tests. The inspector found that the licensee's test director was very knowledgeable of test methodology and was aware of expected results. The test director maintained good communications with control room operators during the performance of the tests, and the test director adequately coordinated the work performed by vendor personnel in setting up and operating test equipment. The inspector observed strict adherence to the procedure and accurate data reduction. All 20 main steam safety valves in Unit 1 were tested, and all valves were found to be within TS limits for set pressure.

5.4 Other Surveillance Observations

- Plant protection system input loop calibration for low pressurizer pressure - Unit 1

6 ONSITE ENGINEERING (37551)

6.1 Emergency Diesel Generator (EDG) Coolers Fouled - Unit 2

On February 21, the licensee discovered large pieces of corrosion products, referred to as nodules, lodged in the tube sheets and inlet passes of the Unit 2 Train A EDG jacket water (JW) and lube oil (LO) coolers during a scheduled inspection of the coolers. The EDG coolers are cooled by the spray pond system. The EDG 2A coolers were last inspected in December 1991 and had

been in service for 38 months. In 1993, the licensee changed the frequency of the cooler inspections to every other outage because the coolers were found to be consistently clean during the previous 18 month inspections. The system engineers promptly initiated a significant condition CRDR to evaluate operability of EDG 2A.

6.1.1 EDG 2A Operability Determination

The JW and LO coolers are double pass coolers with 158 3/4-inch tubes per pass. The spray pond system provides cooling water to the coolers through a 6-inch supply line. The debris was only present in the inlet pass of the coolers. The system engineers recorded the number of tubes that were completely or partially blocked and determined that 21 percent of the inlet pass JW cooler tubes were blocked and 49 percent of the LO cooler inlet pass tubes were blocked.

In September 1994, the licensee measured 657 gpm of spray pond flow to the EDG 2A JW cooler and 361 gpm to the LO cooler. During this time, engineering also determined that the minimum required spray pond flows to the JW and LO coolers during design basis conditions were 400 and 150 gpm, respectively. Engineering revised this calculation to account for the as-found partial blockage of the coolers and determined that the required flows for the JW and LO coolers were 540 and 275 gpm, respectively. Based on these results, the licensee concluded that the as-found flows of 657 gpm for JW cooler and 361 gpm for the LO cooler would have satisfied design basis requirements (even with clogged coolers).

The inspector observed the as-found condition of the EDG coolers and reviewed the engineering calculations used to support operability of the EDG. The inspector concluded that engineering actions to quantify the as-found cooler blockage prior to cleaning the heat exchangers and to revise the design basis calculation to account for cooler blockage demonstrated excellent concern for establishing the safety impact of a degraded condition. The inspector also agreed with the licensee's conclusion that the EDG remained operable in the as-found condition.

6.1.2 Transportability to Other EDGs

The licensee cleaned the EDG 2A JW and LO coolers and measured as-left flows of 690 gpm and 440 gpm, respectively. The licensee then measured flows in the other five EDGs and compared them to the EDG 2A as-left values to determine if any of the coolers may be significantly blocked. Based on the measured flows, the licensee had no immediate concerns with the other five EDGs.

On March 7, the licensee decided to inspect the EDG 2B coolers. The licensee did not inspect the EDG 2B coolers during the scheduled Train B outage, since it had been inspected during the last refueling outage in March 1993. The licensee found that the blockage was much less than EDG 2A (the JW cooler inlet pass was 17 percent blocked and the LO cooler inlet pass was 30 percent

blocked) and concluded that EDG 2B was operable. These findings tended to support a conclusion that the accumulation of corrosion nodules was time dependent.

The inspector concluded that the licensee used conservative judgement to inspect EDG 2B, even though the measured flows appeared to be acceptable. The inspector agreed with the licensee's conclusion that EDG 2B was operable.

6.1.3 1B EDG Inspection

On April 6, the licensee inspected the EDG 1B JW and LO coolers during the scheduled 18-month TS inspection of the EDG. The EDG 1B coolers had been inspected 34 months prior to the Unit 1 refueling outage. The licensee determined that the JW cooler inlet pass was 51 percent blocked and the LO cooler inlet pass was 48 percent blocked. The licensee subsequently determined that the required JW and LO flows to support design basis conditions were 1000 gpm and 275 gpm, respectively, with this amount of cooler blockage. The licensee measured 600 gpm to the JW cooler and 480 gpm to the LO cooler in March of 1995. The licensee subsequently concluded that the actual JW flow was less than the design basis flow for the as-found blockage of the coolers and, in accordance with 10 CFR 50.72, made a 4-hour notification to the NRC on April 7.

The inspector concluded that the licensee promptly evaluated the as-found condition in EDG 1B and made the appropriate operability determination. The licensee noted in their evaluation that the design basis conditions assume a maximum pre-accident bulk spray pond temperature of 89°F. The analysis assumed that following an accident, the maximum water cooler inlet temperature would be 110°F. Typical spray pond temperatures in the heat of the summer have remained between 80 to 85°F since initial plant operation. In April 1995, the bulk spray pond temperature was approximately 60°F. Under these spray pond conditions, the EDG coolers would have provided adequate cooling to maintain EDG operation.

6.1.4 Corrective Actions

The licensee cleaned the EDG 1B coolers, satisfactorily performed all the required retests, and returned EDG 1B to an operable status. The licensee planned to inspect EDG 1A during the current Unit 1 refueling outage and EDG 3A prior to May 1, 1994. The licensee planned to inspect EDG 3B, which was inspected in May 1994, during the next refueling outage in September 1995. The licensee also developed an action plan to inspect the spray pond piping to determine how the corrosion nodules are forming and migrating to the EDG coolers. The results of the spray pond inspections and recommended corrective actions were included in CRDR 9-5-0125, which was under licensee evaluation at the end of the inspection period. The licensee also planned to submit a licensee event report concerning the as-found condition with EDG 1B. The

inspector concluded that the licensee's corrective actions were appropriate and will review the CRDR and licensee event report during routine followup inspections.

7 DESIGN CHANGES AND MODIFICATIONS (37700)

7.1 AFW System Modifications - Unit 2

The inspector observed the installation of a section of 2-inch piping and a 2-inch isolation valve in the steam supply bypass line to the steam-driven AFW pump. The piping and valve were installed using a separate plant change work order that was part of an overall design change to improve the performance of the steam driven AFW pump. The inspector reviewed the engineering design change and 10 CFR 50.59 evaluation, verified the correct procurement specifications for the new piping components using the piping classification, and verified the proper weld type and weld filler material. The inspector determined that the team leader in the field had good knowledge of the design change and the required work. The inspector did not identify any discrepancies during this review.

On March 16, the inspector observed valve services technicians adjusting the reed switch assembly for the bypass valve to the steam-driven AFW Pump SG-134A. The valve had been replaced due to excessive seat leakage that was identified during the previous operating cycle. The inspector noted that the technicians had written in the work order that metal grindings and shavings were found in the valve seat area during the disassembly of the valve. The inspector was concerned that the metal filings may have been introduced due to poor foreign material exclusion controls during the installation of the modification to install the 2-inch piping and isolation valve.

The NA evaluator who was observing the work on Pump SG-134A conducted a followup of the inspector's concern and determined from written observation reports that there were good foreign materials exclusion controls during the installation of the piping modification. The NA evaluator also talked to the mechanics who found the metal filings and determined that the metal filings were probably wear products from the valve seat. The inspector observed the metal filings and noted that they were very small and agreed with the licensee's assessment. The inspector subsequently concluded that the licensee used appropriate FME controls during the installation of the piping modification.

The NA evaluator requested that valve services engineering perform an analysis of the small metal filings as part of the root cause of failure evaluation for the steam leakage of Pump SG-134A. The inspector concluded that the licensee's actions were good and that the NA evaluator's response to the inspectors question was prompt and thorough.

ATTACHMENT 1

1 Persons Contacted

1.1 Arizona Public Service Company

P. Brandjes, Department Leader, Site Maintenance
P. Crawley, Director, Nuclear Fuels Management
B. Grabo, Section Leader, Compliance, Nuclear Regulatory Affairs
W. Hartley, Staff Consultant
L. Houghby, Department Leader, Security
W. Ide, Director, Operations
J. Levine, Vice President, Nuclear Production
R. Lotts, Section Leader, Water Reclamation
J. McDonald, Site Communications
W. Montefour, Senior Representative, Site Communications
G. Overbeck, Assistant to Vice President, Nuclear Production
C. Russo, Department Leader, Nuclear Assurance
J. Scott, Director, Chemistry
C. Seaman, Director, Nuclear Assurance
W. Stewart, Executive Vice President, Nuclear
R. Stroud, Regulatory Consultant, Nuclear Regulatory Affairs

1.2 NRC Personnel

K. Johnston, Senior Resident Inspector
J. Kramer, Resident Inspector
A. MacDougall, Resident Inspector

1.3 Others

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

All personnel listed above attended the exit meeting held on April 13, 1995.

2 EXIT MEETING

An exit meeting was conducted on April 13, 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

ACRONYMS

AFW	auxiliary feedwater
CEDM	control element drive mechanism
CRDR	condition report/disposition request
CRS	control room supervisor
EDG	emergency diesel generator
EHC	electro-hydraulic control
GTG	gas turbine generator
JW	jacket water
LO	lube oil
NA	Nuclear Assurance
NOED	Notice of Enforcement Discretion
RCP	reactor coolant pump
RCS	reactor coolant system
RO	reactor operator
SRO	senior reactor operator
SSM	site shift manager
t-mod	temporary modification
TS	Technical Specification
WRF	Water Reclamation Facility