ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-528 50-529 50-530
License Nos.:	NPF-41 NPF-51 NPF-74
Report No.:	50-528/96-07 50-529/96-07 50-530/96-07
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	April 21 through June 1, 1996
Inspectors:	J. Kramer, Resident Inspector D. Garcia, Resident Inspector D. Carter, Resident Inspector J. Russell, Resident Inspector, San Onofre D. Acker, Senior Project Inspector A. McQueen, Emergency Procedures Analyst B. Olson, Project Inspector P. Goldberg, Reactor Inspector
Approved By:	D. F. Kirsch, Chief, Reactor Projects Branch F

EXECUTIVE SUMMARY

Palo Verde Nuclear Generating Station, Units 1, 2, and 3
NRC Inspection Report 50-528/96-07; 50-529/96-07; 50-530/96-07

This integrated inspection included aspects of licensee operations, engineering, maintenance and plant support. The report covers a 6-week period of resident inspection.

Operations

- The conduct of operations was generally professional and safety conscious (Section O1.1).

- Operators exhibited an overall strong performance during the Unit 1 reduced inventory condition. The dedicated midloop reactor operator displayed an excellent example of board monitoring by noticing unexpected volume control tank level loss due to chemistry sampling (Section O1.2).

- Operators performed the startup of the Unit 1 reactor and main generator in a careful and professional manner. The control room staff appropriately addressed the failure of a control element assembly (CEA) to initially move (Section O1.3).

- The Unit 2 startup communications were generally concise and utilized repeatbacks. The control room supervisor maintained positive control over the evolution. On two occasions, the operators appropriately shut down the reactor when they encountered reactivity discrepancies (Section O1.4).

- Operations management corrective actions for previously identified problems appear to address the observed inconsistency in operator performance (Section O1.5).

- Crew briefings enhanced communications within and between crews (Section O1.6).

- The inspectors identified an example of a violation regarding the failure of operators to follow procedure and declare both trains of low pressure safety injection (LPSI) inoperable. In addition, the operations crew, site shift manager, and a compliance representative decided the LPSI trains were operable by using a justification that did not contain an adequate technical basis (Section O4.1).

- An additional example of a violation was identified regarding the failure of an auxiliary operator to follow the steam generator blowdown system realignment procedure, which resulted in exceeding the licensed thermal power limit by a small amount (Section O4.2).

Maintenance

- The inspectors observed a high level of interaction between the shift supervisor, maintenance engineers, and technicians to ensure that feedwater control system troubleshooting did not result in a feedwater transient (Section M1.1).

- The inspectors observed several maintenance activities during the report period. The activities were performed as required by instructions and in a professional manner (Sections M1.1 and M1.2).

- Troubleshooting efforts to determine the root cause of the initial overspeed trip of the auxiliary feedwater (AFW) pump were extensive and detailed (Section M1.3).

- A noncited violation was identified regarding the failure to verify the correct type of trisodium phosphate required by Technical Specification (TS). The licensee's effort to identify the discrepancy and to obtain an emergency TS change was very good. However, the licensee missed an opportunity to identify another problem with a related surveillance requirement during review and submittal of the emergency request (Section M3.1).

- The inspectors identified a noncited violation regarding the failure of a technician to follow procedures when propping open heating, ventilation, and air conditioning (HVAC) doors. Management's response to the inspectors-identified problem was prompt (Section M4.1).

- A noncited violation was identified regarding the Licensee Event Report (LER) for failure to comply with the TS surveillance requirement to test "at least 10 percent" of the circuit breakers each 18 months (Section M8.1).

- A noncited violation was identified regarding the LER reported containment spray TS violation resulting from an unrecognized mini-flow recirculation valve failure (Section M8.2).

- A noncited violation was identified regarding the LER reported failure to comply with the TS surveillance requirement to verify containment penetration circuit breakers were open (Section M8.3).

Engineering

- Engineering's effort to understand the root cause of American Telephone and Telegraph (AT&T) round cell battery degradation, to better predict future cell performance, and the technical actions in response to the Unit 2 battery test results were excellent (Section E2.1).

- Engineering's original root cause determination of a solenoid valve wire degradation was incorrect, although it was reasonable based on information available at the time. Engineering's planned corrective actions to address the long term environmental qualification of the valves were appropriate (Section E2.2).

- Engineering calculations demonstrated that a full core offload of the fuel assemblies during refueling operations was acceptable (Section E3.1).

Plant Support

- A noncited violation was identified regarding the failure of a chemistry technician to follow procedure. During midloop operations a technician opened a sample valve without notifying the control room and left the area. The loss of inventory had no safety consequence (Section R1.1).

- The containment material condition and housekeeping improved, as compared to the previous Unit 3 containment walkdown. The safety consequence of the debris found in containment was negligible. Additional walkdowns of containment, as jobs were completed, were appropriate (Section R2.1).

- The inspectors identified a violation with three examples of improper posting and inadequate contamination control. Routine tours by RP, maintenance, and operations personnel had not been effective in identifying leaking components which had inadequate contamination controls (Section R2.2).

Report Details

Summary of Plant Status

Unit 1 began this inspection period in Mode 5. The unit was in an outage to replace the shaft on Reactor Coolant Pump 2B. On May 3, the unit returned to 100 percent power and remained at essentially 100 percent power for the duration of the inspection period.

Unit 2 began this inspection period defueled. On May 4, following completion of Refueling Outage 2R6, the unit commenced a reactor startup and power ascension. On May 8, the unit reduced power to 40 percent to repair a leak in a circulating water system manway. On May 10 Unit 2 returned to 100 percent power and remained at essentially 100 percent power for the duration of the inspection period.

Unit 3 operated at essentially 100 percent power for the duration of the inspection period.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety conscious. Specific events and noteworthy observations are detailed in the sections below.

01.2 Midloop (Unit 1)

a. Inspection Scope (71707)

The inspectors reviewed preparations for and control of the reduced inventory operations, conducted in accordance with Procedure 400P-9ZZ16, "Reactor Coolant System Drain Operations."

b. Observations and Findings

On April 21, the inspectors observed the operators drain the reactor coolant system to a midloop condition. The inspectors observed good communications between the operators and a strong command presence of shift supervision. The inspectors observed a nuclear assurance evaluator ask probing procedural and equipment questions.

On April 22, the dedicated midloop reactor operator noted an unexpected response in volume control tank level. The reactor operator's observation subsequently led to the identification of the uncontrolled

loss of inventory caused by an open and unattended sample valve as discussed in Section R1.1.

O1.3 Plant Startup (Unit 1)

a. Inspectors Scope (71707)

The inspectors observed portions of reactor startup performed in accordance with Procedure 400P-9ZZ03, "Reactor Startup." In addition, the inspectors observed portions of main generation and excitation system startup performed in accordance with Procedure 410P-1MB01, "Main Generation and Excitation."

b. Observations and Findings

The inspectors observed the operators withdraw shutdown Group A control element assemblies (CEAs) and noted that the operators performed the operation in accordance with the procedure. When the operators started to withdraw shutdown Group B, CEA 23 failed to move with the rest of the shutdown group and was out of sequence with the other CEAs in the group by approximately 5 inches. The operators attempted to move the CEA in manual with no success. The licensee performed troubleshooting and identified a failed card associated with this CEA. The licensee replaced the card and successfully withdrew shutdown Group B. The inspector found that the licensee's actions were appropriate in stopping operations to identify and correct the equipment problem.

O1.4 Reactor Startup (Unit 2)

a. Inspection Scope (71707)

On May 1, the inspectors observed the initial attempt to perform the Unit 2 reactor startup in accordance with Procedure 400P-9ZZ03, "Reactor Startup."

b. Observations and Findings

The control room supervisor maintained positive control of the evolution by providing appropriate direction to reactor operators, reactor engineers, and other members of the operating staff. The inspectors noted during the startup that operators on two occasions appropriately inserted CEAs due to reaching licensee established administrative limits for differences between the estimated critical position and the critical position plotted during the startup. The engineering aspects of the startup are discussed in Section E1.3.

01.5 Operations Recent Performance

a. Inspection Scope (71707)

The inspectors had discussions with the operations director, an operations department leader, and nuclear assurance operations concerning recent operations performance.

b. Observation and Findings

The licensee had determined that improvements in operation performance were not consistently sustained. Previous NRC inspection reports documented negative findings concerning control board monitoring, attention to detail, and procedural adherence.

The licensee had taken several actions in response to the inconsistencies identified in crew performance:

- The Nuclear Assurance organization assigned a staff of about 15 people dedicated to the assessment of operations performance. This staff performs operations audits and assessments, and operations department training.

- The Operations organization initiated several actions to improve crew performance. Operations management clearly defined a set of operations standards for performance, assured that all operations staff were trained and knowledgeable of the standards, and implemented a practice of discussing standards and shortcomings with individuals involved in events. Several self-assessments of operations performance were conducted, and feedback was provided to the staff. A continuous assessment program was established for use by individuals performing or monitoring activities to assess various attributes of performance in the areas of safety, ownership (watchstanding, monitoring, verification practices, logs, shift turnover, documentation, communications, etc.), professionalism, and leadership. In addition, expectations have been reinforced during requalification crew training.

The results of these initiatives have been manifested by several recent evolutions which were performed well (Units 1 and 2 midloop operations, Units 1 and 2 reactor startups and shutdowns, Unit 2 stuck fuel assembly removal, and Unit 1 reactor coolant pump repair outage). However, as noted in Section 04, additional attention is warranted to establish consistent good performance. The licensee plans to continue implementation of activities to provide further improvement and consistency to operations organization performance.

01.6 Shift Crew Briefings

a. Inspection Scope (71707)

The inspectors attended several operations morning shift crew briefings and held discussions with the auxiliary operators.

b. Observations and Findings

The inspectors observed that auxiliary operators played an active role in the crew briefings. At the start of the brief, each auxiliary operator presented the status of their areas of responsibility. The inspectors found that the auxiliary operators were very familiar with equipment status and problems in their areas of responsibility.

The licensee had established a reflection period of approximately 1 hour, during the middle of the shift, where all nonessential work is stopped. The operations crew members met in the control room and discussed the morning activities and plans for the remainder of the shift. In addition, management utilized the time for lessons learned briefings, as well as safety meetings.

At the end of the shift, operations performed a shift briefing similar to the morning briefing. The briefing allowed the staff to focus on the information passed on to the next crew.

01.7 Conclusions on Conduct of Operations

Operators exhibited an overall strong performance during the Unit 1 reduced inventory condition. The dedicated midloop reactor operator displayed excellent board monitoring by noticing unexpected volume control tank response, resulting in the early identification of reactor coolant inventory loss.

The licensee performed the startup of the Unit 1 reactor and main generator in a careful and professional manner. The licensee appropriately addressed a failure of a CEA to initially move.

The Unit 2 startup communications were generally concise and utilized repeatbacks. The control room supervisor maintained positive control over the evolution. The operators performed appropriately to shut down the reactor when they encountered reactivity discrepancies.

Operations management corrective actions appear appropriate to address the observed inconsistency in operator performance.

The crew briefings enhanced communications within and between crews.

04 Operator Knowledge and Performance

04.1 LPSI Operability (Unit 2)

a. Inspection Scope (71707)

On May 2, during a tour of the control room, the inspectors reviewed the unit log and noted an entry indicating that both trains of LPSI may have been inoperable, but not declared inoperable. Subsequently, the inspectors reviewed the applicable procedures being utilized, 40OP-9SI02, "Recovery from Shutdown Cooling to Normal Operating Lineup," and 40AL-9RK2B, "Panel B02B Alarm Responses."

b. Observations and Findings

The inspectors reviewed the unit log and identified a discrepancy during the performance of the boration of the cold leg injection lines. The unit log indicated that three of four pressure indicators (safety injection tank line pressure) showed pressure greater than 1540 psig, a condition that could impact both LPSI trains. The log also indicated that the shift technical advisor, shift supervisor, site shift manager, and a nuclear compliance representative, discussed the condition and agreed that, since the condition was caused by the performance of an approved plant Procedure (40OP-9SI02) and that actions were taken to promptly rectify the situation, operability of the LPSI trains was not affected.

The licensee had previously determined that if the pressure exceeded 1540 psig downstream of the LPSI injection valves, the valves might not open with the large differential pressure across the valves (pressure locking). Specifically, under worst case design basis, the valve actuator motor would be subject to stall torque conditions and could not open the injection valve.

The inspectors requested a pressure history for the four transmitters from the shift technical advisor. In review of the trends, the inspectors noted that initially all four transmitters indicated that pressure exceeded 1540 psig and that pressure on three of the four remained above 1540 psig for approximately 15 minutes. In addition, the maximum pressure on one of the transmitters reached approximately 1700 psig.

Procedure 40AL-9RK2B, alarm window SI CHK VLV LEAK PRESS HI prescribed, in part, that, if the indicated pressure is greater than 1540 psig, it was necessary to declare the associated LPSI train inoperable and enter the associated TS. The inspectors considered that the licensee's stated reason for not declaring the LPSI trains inoperable (because the operators were performing an approved plant procedure to borate the cold leg injection lines) was without a technical basis and was, therefore, an inadequate justification for operability. In addition, when the

operators decided not to declare the valves inoperable contrary to the actions prescribed by Procedure (40AL-9RK2B), they did not take action to revise the procedure. The inspectors concluded that operators failed to declare both trains of LPSI inoperable as required by 40AL-9RK2B. This is an example of a violation of TS 6.8.1 (50-529/96007-01).

On May 8, the inspectors informed valve services and system engineering groups of the problem. Both groups were unaware of the event and indicated they would perform an operability evaluation based on actual plant conditions to determine if the LPSI trains were, in fact, inoperable. Subsequently, engineering determined that, although the pressure in the alarm response procedure was exceeded, revised calculations with new degraded grid information provided a technical basis that the LPSI valves were operable until the pressure transmitters exceed 1850 psig.

On May 17, the licensee revised Procedure 40AL-9RK2B to reflect the new pressure value and issued a night order to the operating crews to inform them of the change.

04.2 Misalignment of Steam Generator Blowdown System (Unit 2)

a. Inspection Scope (71707)

The inspectors reviewed the licensee's response to the May 11, misalignment of the steam generator blowdown system, which resulted in power operation in excess of the licensed thermal limit.

b. Observations and Findings

On May 11, Unit 2 operators reduced reactor power to 99 percent and performed high rate steam generator blowdowns to the main condenser. Subsequently, an auxiliary operator was dispatched to realign the steam generator blowdown system for normal blowdown to the blowdown flash tank. The realignment was completed, and reactor power was returned to 100 percent.

On May 13, a reactor operator questioned a difference between reactor power calculated from primary plant parameters and reactor power calculated from secondary plant parameters. At the same time, an auxiliary operator questioned the lineup of the blowdown system. Investigation found that the blowdown system from one of the steam generators to the blowdown flash tank was isolated. The isolation of the system resulted in actual reactor power being greater than indicated reactor power.

The licensee calculated that actual reactor power exceeded indicated power by approximately 0.28 percent for a period of 66 hours. The highest rolling 12 hour average of actual reactor power was determined to be 100.27 percent. The inspectors noted that this event was bounded

by the assumptions in the Updated Final Safety Analysis Report (UFSAR) for thermal power of 102 percent.

The inspectors discussed the event with Unit 2 operations management. The inspectors learned that the auxiliary operator had not carried a copy of nor followed Procedure 420P-2SG03, "Operating the Steam Generator Blowdown System," and had relied on memory while realigning the blowdown system. The failure of the auxiliary operator to follow procedure is a second example of a violation of TS 6.8.1 (50-529/96007-01).

The licensee initiated Condition Report/Disposition Request (CRDR) 2-6-0113 to evaluate the event. In addition to determining that the auxiliary operator did not use a procedure to perform the valve realignment, the licensee determined that: supervision was not adequately ensuring the operations expectations were being met with regard to procedural adherence; and control room operators made wrong assumptions regarding the response of indications from the blowdown flash tank after the realignment.

04.3 Conclusions on Operator Knowledge and Performance

A violation was identified involving two examples of failure to follow procedures: the failure to follow the alarm response procedure by not declaring both trains of LPSI inoperable, and the failure to follow the steam generator blowdown procedure, which resulted in slightly exceeding the licensed thermal power limit.

The decision that the LPSI valves were operable was based on inadequate technical information and did not include engineering's evaluation. An engineering evaluation of the situation was not performed until the inspectors raised questions. The licensee performed additional engineering evaluations and concluded that the LPSI system was operable at the pressures encountered and revised the procedure to include the new operability criteria.

The licensee appropriately initiated an investigation into the causes of the misalignment of the steam generator blowdown system. The results of their preliminary investigation appeared to reflect the causes of the event.

08 MISCELLANEOUS OPERATIONS ISSUES (92901)

08.1 (Closed) LER 50-529/94007: momentary entry into TS 3.0.3 due to personnel error. This LER was a minor issue for which the licensee's actions were appropriate. This LER was closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments on Maintenance Activities

a. Inspection Scope (62703)

The inspectors observed all or portions of the following work activities:

- 32MT-9SB03 Maintenance of Westinghouse Type DS-416 Reactor Trip Switchgear (Unit 3)
- 31MT-9RC06 Reactor Coolant Pump Disassembly and Assembly (Unit 1)
- WO 0756393 Troubleshoot Feedwater Control System to Determine Cause of Spurious Oscillations (Unit 2)

b. Observations and Findings

The inspectors found these work activities were performed in accordance with procedures. In particular, the inspectors observed a high level of interaction between the shift supervisor, maintenance engineers, and technicians to ensure that the feedwater control system troubleshooting (WO 07566393) did not result in a feedwater transient. In addition, see the specific discussions of maintenance observed under Section M1.3.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillance activities:

- 32ST-9SB02 18 Month Surveillance Test for Westinghouse Type 4DS-416 Reactor Trip Breakers (Unit 3)
- 42ST-2SG03 Testing Atmospheric Dump Valves in Mode 3 (Unit 2)
- 42ST-2ZZ24 Startup Channel High Neutron Flux Alarm Inoperable 3.1.2.7 (Unit 2)

b. Observations and Findings

The inspectors found these surveillances were performed as specified by applicable procedures.

M1.3 AFW Pump Trip (Unit 2)

a. Inspection Scope (62703)

On May 1, the inspectors observed initial troubleshooting of the overspeed trip of the turbine driven AFW pump during the Unit 2 startup. In addition, the inspectors reviewed the operability determination and discussed the determination with maintenance, engineering, and operations. On May 17, the inspectors observed a performance test of the AFW pump.

b. Observations and Findings

Approximately 10 minutes into a postmaintenance test run, the AFW pump speed ramped up over a 15 second period, and the pump tripped on overspeed. The licensee initiated an investigation team to troubleshoot and gather data. The licensee instrumented and performed additional test runs of the pump. Equipment evaluated by troubleshooting included: the governor valve linkage, turbine governor controls (both electric and hydraulic), DC control power, and the steam drains. After comprehensive troubleshooting, the licensee concluded that no abnormal conditions which would impact future turbine operation could be found. The licensee wrote an operability determination which included the results of the troubleshooting.

The licensee initiated a weekly pump testing program on the AFW pump to monitor and detect abnormal pump performance. On May 17, the inspectors observed one of the weekly tests and noted no discrepancies.

c. Conclusions

The licensee performed extensive troubleshooting efforts to determine the root cause of the initial overspeed trip of the AFW pump. The licensee appropriately performed additional tests of the AFW pump. Based on the troubleshooting and additional tests, the inspector concluded that the licensee's operability determination was reasonable.

M3 Maintenance Procedures and Documentation

M3.1 Emergency TS Change

a. Inspection Scope (61726)

The inspectors reviewed the licensee's entry into TS 4.0.3 and their emergency request for a TS change concerning trisodium phosphate maintained in containment.

b. Observations and Findings

On May 14, the licensee entered TS 4.0.3 after determining that part of TS Surveillance Requirement 4.5.2.d.2, to verify every 18 months that a minimum of 464 cubic feet of trisodium phosphate was located in containment, had not been performed in the three units. During a review of the TS, the licensee found that the form of trisodium phosphate located in containment was anhydrous rather than dodecahydrate, as specified by the TS. On May 15, the licensee submitted an emergency request to change the TS to specify that anhydrous trisodium phosphate was to be verified in containment. The emergency request was approved, and the licensee exited TS 4.0.3.

The inspectors discussed this event with chemistry and nuclear licensing personnel and reviewed original design calculations, purchase orders, and the original TS. The licensee was designed for anhydrous trisodium phosphate to condition water in the containment sump following a loss of coolant accident. However, the original TS was approved indicating that the dodecahydrate form of trisodium phosphate would be used.

Surveillance Requirement 4.5.2.d.3 tested the ability of a specific amount of trisodium phosphate to condition water from the refueling water storage tank. The inspectors questioned chemistry personnel about the requirement and whether the amounts specified by the test were based on the anhydrous or dodecahydrate form of trisodium phosphate. The chemistry department subsequently determined that the amounts specified were based on the dodecahydrate form of trisodium phosphate. On May 20, the licensee performed a determination using some of the original trisodium phosphate design calculations to confirm that operability was maintained.

The inspectors observed that Section 6.1.1.2 of the Palo Verde UFSAR indicated that trisodium phosphate dodecahydrate would be used in containment. Section 6.1.1.2 indicated that the chemical would be tested, but the test parameter for water temperature differed from the water temperature listed in Surveillance Requirement 4.5.2.d.3.

The licensee developed an action plan to address this issue. The inspectors reviewed the plan and found that the licensee intended to develop a new test to verify the ability of anhydrous trisodium phosphate to condition water from the refueling water tank. The licensee intended to revise Surveillance Requirement 4.5.2.d.3 based on the new test. The licensee also intended to investigate and correct the inconsistencies between the surveillance requirements and the UFSAR.

While the licensee maintained the design basis, the Surveillance Requirement 4.5.2.d.2 to verify the type of trisodium phosphate located in containment was not met. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-528;529;530/96007-02).

Resolution of the UFSAR inconsistency will be reviewed in a future inspection (IFI 50-528;529;530/96007-03).

c. Conclusions

One noncited violation, regarding the failure to meet the TS Surveillance Requirement 4.5.2.d.2, was identified.

The licensee's effort to find the discrepancy for the type of trisodium phosphate used in containment and to obtain an emergency TS change was very good. However, the licensee missed an opportunity identify another problem with a related surveillance requirement during review and submittal of the emergency request. The licensee's action plan to resolve this entire issue was appropriate.

M4 Maintenance Staff Knowledge and Performance

M4.1 Containment Ventilation Purge Isolation Valve Leak Rate Test (Unit 3)

a. Inspection Scope (61726)

On May 7, the inspectors observed performance of Procedure 73ST-9CL10, "Containment Ventilation Purge Isolation Valves (42") - Penetration 57."

b. Observations and Findings

The inspectors noted that the objective of the test was to verify that the leakage rate of the containment purge isolation valves was within the limits specified in TS. The test accomplished the objective by pressurizing the volume between the two valves (inside and outside of containment purge isolation valves) by applying air to the drain/test valve located between them.

The technician was unable to properly pressurize the volume between the valves. The licensee stopped the surveillance test and entered the appropriate action statements. The licensee determined that the valve outside containment was not seated properly. Following maintenance on the valve, the technician reperformed the test satisfactorily.

The inspectors noted several discrepancies during the performance of the initial surveillance test. The local leak rate test (LLRT) technician failed to perform the procedure in sequential order. The technician performed Step 8.7 prior to performing Steps 8.5 and 8.6. Step 8.7 opens the drain/test valve; Steps 8.5 and 8.6 attach test fittings and connect an air supply, respectively. Although the failure to perform the procedure in sequential order did not have an impact on the outcome of the test, the action did not meet management's expectation.

During the performance of the test, the inspectors observed two propped open HVAC doors, A347 and A348, through which a rubber service air hose

protruded. The doors were labeled with direction to contact fire protection prior to propping open. The technicians indicated that they had not contacted fire protection or any other organization prior to propping open the doors. The doors were listed as HVAC barrier doors in Procedure 40AC-90P17, "Control of Security, Fire and HVAC Barrier Doors, Hatches and Floor Plugs." The procedure indicated that fire protection was to be contacted prior to propping open doors to ensure that appropriate compensatory measures were implemented. The inspectors contacted fire protection, and they determined that no compensatory measures would have been required for the propped open doors. The failure to contact fire protection prior to propping open the doors constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (50-530/96007-04).

The inspectors discussed the performance of the test with the licensee. The licensee initiated a CRDR to evaluate the event. Maintenance supervision discussed the issues of concern with all the LLRT technicians and reinforced management's expectations.

c. Conclusions

The inspectors identified that licensee personnel failed to follow procedures and instructions when propping open two labeled HVAC barrier doors. Management's response to the problem was prompt and thorough.

M8 Miscellaneous Maintenance Issues (90712)

M8.1 (Closed) LER 50-528/94001-01: Surveillance Requirement 4.8.4.1 not fully met. The licensee determined that they did always comply with the TS surveillance requirement to test "at least 10 percent" of the circuit breakers each 18 months. Due to rounding, the licensee sometimes tested less than 10 percent of the breakers; however, their program would have ensured 100 percent testing over 10 years.

As corrective action, the licensee tested other circuit breakers to ensure that the "at least 10 percent" requirement was met. The licensee also changed preventive maintenance tasks to ensure that the sample size would meet the requirement.

The inspectors reviewed CRDR 9-3-0569 which included the licensee's investigation of this event. The inspectors found the licensee's investigation to be thorough and their corrective actions to be appropriate. The inspectors also reviewed a sample of the preventive maintenance tasks and found that the test sample size met the 10 percent requirement. This failure constitutes a licensee-identified and corrected violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (50-528/96007-05).

M8.2 (Closed) LER 50-528/95016: TS violation due to unrecognized containment spray valve failure. The Train B mini-recirculation motor-operated valve failed when a motor set screw was tightened, binding the motor. The licensee found that the motor's stator had previously been replaced and had been machined to allow proper fit into the motor housing. The licensee determined that enough material had been removed to affect the ability of the set screw to hold the motor in place. The licensee determined that the valve had been inoperable for greater than 72 hours, in violation of TS 3.6.2.1.

The licensee corrected the problem by adding a shim around the stator, and the valve operator was reoriented to improve performance. The licensee also inspected other similar valves and verified those to be operable.

The inspectors reviewed CRDR 1-5-0231, which included the licensee's investigation of this event. The inspectors found the licensee's investigation to be thorough and their corrective actions to be appropriate. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-528/96007-06).

M8.3 (Closed) LER 50-529/95004: TS violation due to missed surveillance requirement. On two occasions, two inoperable containment penetration circuit breakers were not verified to be open every 7 days as required by TS 3.8.4.1, Action a. The licensee subsequently identified that the breakers had remained open and were under clearance control. The licensee's corrective actions included the use of a controlled procedure for subsequent verifications of breaker positions and a review of the procedure after completion of the task.

The inspectors reviewed CRDR 2-5-0250, which included the licensee's investigation of this event. The inspectors found the licensee's investigation to be thorough and their corrective actions to be appropriate. This failure constitutes a licensee-identified and corrected violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (50-529/96007-07).

III. Engineering

E1 Conduct of Engineering

E1.1 Reactor Startup (Unit 2)

a. Inspection Scope (37551)

On May 1, the inspectors observed the Unit 2 reactor startup in accordance with Procedure 400P-9ZZ03, Reactor Startup, and evaluated engineering's response to identified reactivity anomalies.

b. Observations and Findings

During the reactor startup, the inspectors observed the reactor engineer and shift technical advisor correctly enter the information into the computer to perform the 1/m plot. Two consecutive anticipated critical positions projected that the reactor would achieve criticality 500 pcm below the estimated critical position. In accordance with licensee administrative procedures, operators inserted the regulating group control element assemblies, and engineering and management evaluated the condition.

The licensee initiated a CRDR to evaluate the problem. Reactor engineering reviewed previous reactor startups and noted similar characteristics during previous startups. The licensee determined that the estimated critical position was accurate. The licensee determined that it was appropriate to perform another startup.

Operators performed the second startup and did not receive two successive anticipated critical positions within 500 pcm below the estimated critical position. However, as operators performed the second approach to criticality, engineering determined that with the next pull of the CEAs the reactor would become critical at a point 500 pcm below the estimated critical position. The licensee again performed a reactor shutdown.

The licensee evaluated the condition and noted that this was the first startup that included an 11 parts per million boron adjustment for the use of guardian grid fuel. Approximately two-thirds of the fuel assemblies in Unit 2 were manufactured with the guardian grid. The licensee initially inserted the 11 parts per million adjustment to increase the accuracy of the low power physics test predictions based on the results of the recent Unit 3 refueling startup. The licensee removed the guarding grid bias from their "simulate" model prediction, which lowered the estimated critical position, and successfully performed the reactor startup.

The inspectors noted that the 500 pcm limit was a licensee administrative requirement based on the TS requirement that the overall core reactivity balance shall be compared to the estimated values and agree within 1000 pcm. The licensee planned to continue to evaluate the reactivity discrepancies.

c. Conclusions

Following the second startup attempt, engineering research into the startup anomalies was thorough and had appropriate management review.

The licensee decisions to shut down when administrative limits were approached was conservative.

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Class 1E Battery Test Results (Unit 2)

a. Inspection Scope (92903)

The inspectors reviewed the test data from the Class 1E battery testing performed during the recent outage, inspected the batteries, reviewed licensee corrective actions, reviewed licensee operability evaluations, and discussed preliminary root causes for the degradation of the AT&T round cell batteries with licensee personnel.

b. Observations and Findings

During the recent outage, the licensee performed battery performance discharge (capacity) testing of the Class 1E batteries. The licensee noted that the capacity of the batteries was below expectations.

Surveillance Requirement 4.8.2.1.e requires that AT&T batteries demonstrate 90 percent or greater capacity when subject to a performance discharge test. Surveillance Requirement 4.8.2.1.f requires that AT&T batteries be tested annually if their capacity drops below 95 percent or more than 5 percent since the previous test.

Battery A tested at 107 percent, a reduction of 7 percent since the previous test. Battery C tested at 88 percent, a reduction of 20 percent since the previous test. Test equipment failed during testing of Battery D.

The licensee had previously picked the "best" individual cells from several different lots of cells. Therefore, the batteries contained cells manufactured at different times with different testing histories. The licensee determined that the recent Unit 2 battery degradation was lot related. For example, Battery C contained cells from lots HG-1, HG-14, HG-16, and HG-18. For battery C, the capacitances of the lots were: HG-1, 114 percent; HG-14, 91 percent; HG-16, 105 percent; and HG-18, 82 percent. The lots experienced similar results in Battery A.

In order to comply with the TS surveillance, the licensee reconfigured the cells in all four batteries. Battery A currently contains HG-1 cells, Battery B contains new cells from the manufacturer, Battery C contains HG-16 cells, and Battery D contains new cells received from another utility.

The licensee's preliminary root cause investigation identified positive plate destruction on the HG-18 cells. In addition, the licensee determined that the vendor had increased the amount of platinum in the

negative plate of cells produced after mid 1994. The vendor added additional platinum to the negative plate to improve the float behavior of the cells. The platinum decreased the charging efficiency of the negative plates to more closely match the charging efficiency of the positive plates. Subsequent testing of batteries in all three units showed corresponding lower negative half-cell voltage readings in the Unit 2 batteries, when compared to the readings from the Units 1 and 3 batteries, which contained the lower amount of platinum.

The licensee planned to evaluate the effect the increase in platinum in the negative plate may have on the long term capacity of the Unit 2 batteries. In addition, the licensee planned to continue to monitor the positive and negative plate performance of the Unit 2 batteries by taking half-cell voltage readings. The licensee informed the NRC of potential generic issues concerning AT&T round cell batteries through several meetings and conference calls.

c. Conclusion

The Unit 2 reconfigured Class 1E batteries were operable and met the TS requirements. The licensee's effort to understand the root cause of AT&T round cell battery degradation, in order to better predict future cell performance, and the technical actions in response to the Unit 2 battery test results were excellent.

E2.2 Solenoid Valve Operator Degraded Internal Wiring

a. Inspection Scope (92903)

Inspection Report 50-528;529;530/95025, Section 7, discussed resolution of a problem with overheating of certain solenoid valves inside containment. Subsequent to this report, the licensee identified similar problems with pressurizer steam space sample line containment isolation Valve SS-UV-205 in Unit 2 which indicated that the original root cause was incorrect. The inspectors reviewed the problem with Valve SS-UV-205 and discussed corrective actions with the licensee.

b. Observation and Findings

The licensee had determined that certain solenoid valves had heat damaged wire insulation and environmental seals because their electrical circuits had failed and the solenoids were continuously energized with 120 VAC, in lieu of the nominal 42 VAC. The licensee had replaced the heat damaged equipment and repaired the electrical circuits.

Subsequently, the licensee identified that solenoid Valve SS-UV-205 had a heat damaged environmental seal. Electrical checks indicated that the valve had not been subjected to an over-voltage condition. Based on this new information and the temperature measurements on the external surface of a similar valve, the licensee determined that the

environmental qualification life of several of the valve's internal components may be nonconservative. Because the licensee had recently inspected and repaired Valve SS-UV-205 in Units 2 and 3, the licensee concluded these valves were operable. The licensee deenergized and tagged Valve SS-UV-205 in Unit 1 in the required safety position. The inspectors verified that the Unit 1 valve was deenergized and tagged. This type of solenoid valve and environmental seal were used in other systems within containment, but with lower process fluid temperatures. The licensee noted that inspection of these valves indicated no heating problems. The licensee indicated that they have not experienced failures of this type valve, only degradation of environmental seals and internal wiring.

The licensee planned to perform laboratory testing of this type of valve to determine the expected internal temperatures and adjust environmental qualification life as required. The licensee further planned to modify the valves to lower the temperature at the environmental seal area and remove the internal wiring with the lowest temperature rating. The licensee planned to complete these actions in Unit 1 to support the next outage.

c. Conclusion

The licensee's operability determination was acceptable, pending the testing results. The licensee's original root cause determination was incorrect, although it was reasonable based on information available at the time. The licensee's planned corrective actions to address the long term environmental qualification of these valves appear appropriate.

E2.3 Review of Facility and Equipment Conformance to UFSAR Description

A recent discovery of a licensee operating its facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable sections of the UFSAR that related to the inspection areas inspected. The following inconsistency was noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors.

As noted in Section M3.1, the inspectors identified a difference was identified between the criteria for trisodium phosphate contain in the TSs and UFSAR section 6.1.1.2.

As noted in Section E3.1 the inspectors identified several differences between licensee procedures, the Combustion Engineering Standard Safety Analysis Report, and UFSAR Section 9.1.3.3 concerning the SFP. These differences were:

- Cooling lineup prescribed to cool SFP, when shutdown cooling is not needed.
- Description of water depth above fuel assemblies.
- Primary source of cooling water to the heat exchangers, primary heat sink, and primary makeup source.

E3 Engineering Procedures and Documentation

E3.1 Spent Fuel Pool Current Licensing Basis

a. Inspection Scope

Representatives of the NRC's Office of Nuclear Reactor Regulation reviewed UFSAR Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup System," and the licensee's operation of the system in accordance with the UFSAR descriptions.

b. Observations and Findings

UFSAR Section 9.1.3.3.1.1 states that one train each of the shutdown cooling system and the fuel pool cooling system will be in use in the event of a full core offload. Under these conditions, (a core offload 90 days after startup from previous refueling and the pool containing fuel from 12 previous refuelings) the maximum pool temperature will be limited to less than 125.2°F. The inspectors noted that UFSAR Table 9.1-2 lists the maximum fuel pool temperature as 145.5°F, with a footnote stipulating that this was the design heat load (one-third core offload) with one fuel pool cooling train out of service. The information in this table did not show that a calculation for a full core offload with one train of spent fuel pool (SFP) cooling had been performed and will maintain maximum fuel pool temperature less than 145.5°F. The inspectors verified that the information in UFSAR Section 9.1.3.3.1.1 shows with a maximum heat load (full core offload), and a fuel pool cooling train augmented by a shutdown cooling train, the licensee has a calculation on record indicating that pool temperature remained less than 125.2°F.

The licensee noted that the SFP cooling pumps were not in the inservice testing program because the pumps do not fall under the American Society Of Mechanical Engineering (ASME) Section XI applicability, as described in a letter to the staff on December 12, 1984. The letter explained that there was substantial assurance that these pumps were ready to operate on demand since they were normally running. In a recent review of the in-service testing program, the licensee identified the need to routinely monitor the performance of the fuel pool cooling system and issued a CRDR to evaluate the concern.

Procedure 410P-1PC01, "Fuel Pool Cooling," provided lineups for the SFP cooling trains. Section 3.0 of the procedure states that a single pump and two heat exchangers should be attempted to maintain fuel pool temperature less than 145°F prior to initiating shutdown cooling. The UFSAR states that this lineup should be used to maintain temperature less than 125°F, and that two pump two heat exchanger operations should be employed above 125°F. The licensee planned to address the discrepancy between the UFSAR and procedures. The inspectors verified that Section 4.3.5 of the Procedure 410P-1PC01 directs the operator to augment with shutdown cooling if temperature exceeds 145°F. The inspectors also verified that the TS requirement to not move fuel prior to the reactor being shutdown 100 hours had been satisfied for the last three refueling outages.

The inspectors noted that UFSAR Section 9.1.3.3.1.3 states that "a minimum of 9 feet of water is maintained over spent fuel assemblies." However, TS 3.9.11 requires 23 feet over the top of the fuel assemblies seated in the storage racks. The licensee responded that UFSAR 9.1.4.6 describes the Combustion Engineering Standard Safety Analysis Report interface requirement to maintain 9 feet of water above the active portion of a fuel assembly during fuel handling, and UFSAR 9.1.4.7 describes the ability to meet that requirement. Further, Combustion Engineering Standard Safety Analysis Report Section 9.1.4.3.4, which is referenced in UFSAR Section 9.1.4.3.4, describes travel stops in both the refueling and spent fuel handling machines that restrict withdrawal of the spent fuel assemblies to maintain the minimum 9 feet of water over fuel being moved. The licensee planned to review the need to supplement UFSAR Section 9.1.3.3.1.3 to clarify that the 9 feet requirement was for fuel being moved, and that there was a 23 foot TS requirement above fuel assemblies seated in the storage racks.

The inspectors noted that UFSAR Section 9.1.3.3.1.1 lists essential cooling water prior to nuclear cooling water as the cooling source to the SFP heat exchanges. The inspectors noted that nuclear cooling water should be listed first since it is the normal method. The inspectors verified that the licensee has a procedure for manually initiating essential cooling water. The inspectors also noted that UFSAR Section 9.1.3.3.1.1 stated that the spray ponds were the SFP cooling ultimate heat sink. This would only be true if the licensee had switched the heat exchanger cooling to its backup (essential cooling water) source.

The inspectors questioned certain control room staff regarding normal makeup paths to the SFP. The control room staff indicated that the normal makeup method was the liquid radwaste system monitor tank (in order to minimize waste). However, UFSAR Section 9.1.3.3.1.3 states that normal pool makeup is from the refueling water tank. The backup source is from liquid radwaste system monitor tank or condensate storage tank. Plant procedures address makeup from all of the above sources.

The licensee indicated that they would review the noted UFSAR discrepancies and clarify that a full core offload was routinely performed. These changes were not completed prior to commencement of the Unit 2 refueling outage that started March 16, 1996. Additionally, the licensee planned to review the UFSAR sections pertaining to the SFP to further verify the consistency between actual plant operation and UFSAR descriptions. Resolution of the UFSAR inconsistency will be reviewed in a future inspection (IFI 50-528;529;530/96007-03)

c. Conclusion

Since the plant has two independent SFP trains (each capable of being augmented by a shutdown cooling train), and has stored less than half of the maximum design number of spent fuel assemblies, the licensee demonstrated that a full core offload of fuel assemblies (the normal practice) was acceptable.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) LER 50-529/94005-01: high pressure safety injection motor operated valve failed to open during ASME Section XI testing. The valve failure resulted in one subsystem of the emergency core cooling system being inoperable. The failed valve (2JSIAUV0627) was a 2 inch rotating stem globe valve with a Limitorque SMC-04 actuator.

The licensee determined that the root cause of the failure of the valve to open was a combination of pressure over the seat and excessive stem to disc friction. Downstream check valve leakage caused the pressure over the seat. The licensee did not determine the specific cause of the excessive stem to disc friction. However, the licensee determined that both the pressure over the seat and a high stem to disc friction had to occur simultaneously for the failure to be repeated.

The licensee indicated that the Limitorque SMC-04 actuator was obsolete and not supported by the original manufacturer. The licensee indicated that a previously approved design change was implemented to upgrade the Limitorque SMC-04 actuator to a Limitorque SMB-00 actuator. The inspectors reviewed draft equipment root cause failure analysis, CRDR 9-4-0598, and the report, "Generic Evaluation of the Limitorque SMC-04 Actuator and Borg Warner 2 Inch Angle Globe Valve in HPSI Service," Revision 0. The report indicated that a conservative determination of the SMC-04 actuator torque required to operate the valve was approximately 75 ft-lbs, without considering seating torque. The licensee concluded that the SMC-04 actuator maximum output combined with packing load adjustment could not accommodate the valve torque requirements. Therefore, the licensee installed the SMB-00 actuator with a 250 ft-lb rating. The inspectors reviewed Work Order 681034 which replaced the SMC-04 actuator with the SMB-00 and noted the work was completed October 19, 1994.

In addition, the valve had a rotating stem which resulted in operating torque loads on the actuator which were not taken into account when the original application was determined. The licensee indicated that a modification had been approved to change the valve from a rotating stem to a rising stem valve which would eliminate the stem to disc friction. The licensee issued a purchase order to the valve manufacturer to design a new valve.

The inspectors concluded that the licensee had taken appropriate short and long term corrective actions.

E8.2 (Closed) Violation 50-530/94012-03: failure to take immediate action required by TS. This violation indicated that the feeder breaker for the Train A LPSI pump was racked into the test position rendering the associated shutdown cooling loop inoperable. In addition, immediate action was not initiated to restore the shutdown cooling loop to service or to establish at least 23 feet of water above the reactor pressure vessel flange as required by TS. The licensee stated they had not considered the pump inoperable because they had taken credit for manual operator action. The licensee stated that they had reasonable assurance that the breaker could have been racked back in within the 3-hour time period required to initiate shutdown cooling.

The licensee's corrective actions included surveying nuclear utilities to determine how other utilities view manual operator actions for the LPSI pump. The licensee concluded that the majority of the utilities would have considered the pump inoperable. The inspectors reviewed Procedure 40DP-90P26, "Operability Determination," Revision 3, Appendix C. The licensee had revised this procedure to include guidance for use of manual actions to maintain operability. Appendix C of this procedure listed the actions which had to be performed in order to take credit for manual operation. It also included evaluations of the qualifications and ability of the personnel performing actions, the number of qualified personnel needed, the time needed to accomplish the actions, the communications necessary, and the criteria of 10 CFR 50.59.

The inspectors reviewed CRDR 3-4-0340, dated July 15, 1994, which was prepared to evaluate the licensee's position on appropriate manual actions to support continued operability. The licensee developed a position paper and distributed it to operators in the three units. The position paper which contained the minimum requirements to credit manual operator actions in maintaining operability was an expanded version of the Appendix C operability determination procedure. The inspectors concluded that the licensee's corrective actions were appropriate.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Chemistry Sampling During Midloop (Unit 1)

a. Inspection Scope (71750)

On April 22, with Unit 1 in midloop operations, the midloop reactor operator noted an unexpected level decrease in the volume control tank. Subsequently, the licensee determined that chemistry personnel had begun a purging operation associated with reactor coolant sampling without required notification to the control room. The inspectors reviewed the licensee's response to the event, corrective actions, and discussed the event with chemistry personnel.

b. Observations and Findings

At approximately 11 a.m., on April 22, the senior chemistry technician and a chemistry technician discussed performing the required shiftly reactor coolant system sample in accordance with Procedure 740P-9SS01, "Primary Sampling Instruction." The chemistry technician initiated the purging process by opening a sample valve with an understanding that the senior chemistry technician would actually draw the sample. The technician left the area. The inspectors noted that the purging process takes approximately 15 minutes at a flow rate 0.5 to 1 gallon per minute. The senior chemistry technician believed the chemistry technician was doing the entire sample. Neither technician notified the control room. Procedure 740P-9SS01, Step 4.3.4 requires notification of the control room prior to sampling.

At approximately 12:30 p.m., the midloop reactor operator detected a slight loss in volume control tank level. A control room operator contacted chemistry and discovered that the sample purge had been initiated and was still in progress. The reactor operator estimated that the volume control tank decreased by approximately 1.5 percent or approximately 60 gallons.

The licensee discussed the event in the control room with operations, chemistry personnel, and the site shift manager. Chemistry determined that the flow rate was approximately 0.75 gallons per minute and that the total loss of inventory from the volume control tank was approximately 80 gallons. The licensee initiated a CRDR and notified chemistry management. The site shift manager did not contact the operations department leader or the operations director during the shift. The licensee notified the NRC approximately 24 hours after the event.

The licensee determined that the root cause of the event was the failure to follow procedure by the chemistry technician in that the technician

did not notify the control room prior to sampling. In addition, communications and notifications to licensee management and the NRC did not meet management's expectations.

The inspectors concluded that the licensee's corrective actions were appropriate. Additionally, the inspectors noted that the event was identified by the licensee and that there were no similar violations identified by either the inspectors or by the licensee which could have reasonably prevented this occurrence. This licensee-identified and corrected violation, failure to notify the control room prior to sampling, is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-528/96007-08).

c. Conclusions

Chemistry personnel did not follow procedures for notifying the control room prior to sampling, resulting in a noncited violation. In addition, chemistry personnel failed to adequately communicate, resulting in an unattended open sample valve and subsequent loss of inventory during midloop operations. The inventory lost was not significant.

The licensee's investigation into the event was thorough. The notifications to operations management were slow, in that the event was not discussed until the following day.

R2 Status of Radiological Protection & Chemistry Facilities and Equipment

R2.1 Containment Closure Walkdown (Unit 2)

a. Inspection Scope (71750)

On April 30, the inspectors, accompanied by a radiation protection (RP) technician and the containment coordinator, toured the containment to assess the state of housekeeping and material condition prior to the unit startup.

b. Observations and Findings

The containment cleanliness and material condition was generally good. The inspectors observed minor debris, such as tie wraps, in the reactor coolant pump areas. The RP technician immediately retrieved the debris. The containment coordinator indicated that the pump bay areas would be recleaned to ensure all small material was removed. There were minor material discrepancies with the few remaining jobs in containment. The containment coordinator indicated that additional walkdowns would be performed to verify containment cleanliness as the work was completed.

R2.2 Material Condition of the RCAs (Units 1, 2, and 3)

a. Inspection Scope (71750)

The inspectors made tours of the radiologically controlled areas (RCA's) in each of the units. Additionally, on May 9, the inspectors and a NRC manager toured the RCA's for all three units.

b. Observations and Findings

On May 9, the inspectors identified two Unit 2 leaks which were not posted as contaminated areas. For both leaks, the previously unidentified contamination levels were greater than the licensee's criteria for posted contamination areas (greater than 1000 disintegrations per minute per 100 square centimeters (dpm/100cm^2).

- Valve SIA-UV-655 had a packing leak. RP determined that the floor under the valve had smearable contamination of 15,000 dpm/100cm^2. RP subsequently posted the area as a "contaminated area." The inspector determined that the packing for this valve had been worked during the refueling outage. Maintenance and RP had performed walkdowns of the area on May 1 and May 6, respectively, and had not identified leakage or any contamination.

- The pipe cap down stream of valve SIB-V555 appeared to be leaking, with boron crystals apparent on both the pipe cap and the floor. RP subsequently determined that smearable contamination was 30,000 dpm/100cm^2 on the pipe cap and 70,000 dpm/100cm^2 on the floor. RP decontaminated the valve and cleaned up the area. The inspector determined that SIB-V555 had been previously identified by the utility maintenance group as having a packing leak. Maintenance and RP had performed walkdowns of this area on May 1 and May 3, respectively, and had not identified leakage or any contamination.

During the May 9 tours, the inspectors also observed that Unit 1 valve SIA-UV-655 had a packing leak. The bonnet was posted as a "High Contaminated Area," and there was a drip catch installed underneath the valve bonnet area to contain the leak. The inspector observed that a stalactite of boron crystals had formed outside the drip catch.

On May 10, the NRC manager discussed the general conditions of the RCAs with licensee management. Licensee management subsequently directed RP and utility maintenance personnel to perform walkdowns of the RCA's in all three units. As a result of the walkdowns, the licensee identified numerous valves and pumps that needed repair and/or decontamination. Licensee management classified these material condition issues as a RP Management Level 1 issue, establishing a high priority for resolution and increased management awareness. In addition, the licensee initiated CRDR 9-6-0557 to investigate the discrepancies.

On May 14 and 15, a NAP inspector performed radiological walkdowns in all three units and documented the results in Evaluation Report 98-0303. The NAP inspector identified two contaminated leaking valves in Unit 2 and one in Unit 1 which had not been properly posted. The NAP inspector did not identify Unit 1 valve SIA-UV-655 as having improper posting.

On May 16, the inspectors toured the Unit 1 RCA and observed that the stalactite formation outside the drip catch of valve SIA-UV-655 had allowed liquid to drip onto the floor, forming a puddle. This area had not been posted as a contaminated area. The inspector contacted RP, and a technician determined that the contamination levels on the floor were up to 40,000 dpm/100cm^2. The utility maintenance technicians decontaminated the area and extended the drip catch under the valve.

On May 21, the inspectors discussed the Unit 1 valve SIA-UV-655 observations with the NAP inspector. On May 22, the NAP inspector observed a puddle on the floor under the valve in an area that was not posted. The NAP inspector found 150,000 dpm/100cm^2 smearable contamination on the floor, which met the criteria for a "high contamination area." The NAP inspector notified RP, who posted the floor as a "high contamination area."

The inspectors held discussions with RP management and reviewed the licensee's program for identifying leaking components and controlling contaminated areas. The inspectors identified the following:

- RP technicians were required by procedures to perform monthly and weekly surveys of the RCA. The surveys for the SIA-UV-655 valves were performed monthly, and the survey for the SIB-V555 was performed weekly. The most recent surveys had been performed within a week of the May 9 NRC walkdown. The surveys did not identify the valves or the areas under the valves as contaminated.

- The RP program included both shiftly tours by RP and area ownership for technicians. RP management stated their expectations are that technicians should be performing both spot-checks and detailed tours of their area.

- The licensee had established a Zone Inspection Program (ZIP) to provide additional controls and responsibilities for utility, mechanical maintenance, and operation departments for identifying and tracking leaking components. The program had established a monthly walkdown of each unit. However, the program was discontinued in Unit 2 during the outage, and RP was given the responsibility for contamination control.

- The licensee had previously recognized that the packing for the SIA-UV-655 valves were unevenly loaded, contributing to packing leakage. Although the packing on the Unit 2 valve had recently

been adjusted, it appeared that the licensee had removed an installed drip catch without verifying the success of the adjustment. Unit 1 valve SIA-UV-655 had an open work request, initiated in January 1994, to address packing leakage.

- In February 1996, NAP documented concerns in Evaluation Report 96-0089, that contaminated areas/components were not being identified during RP tours and surveys. NAP had concluded that communications between RP, maintenance, and operations personnel were inadequate. In addition, NAP found that documentation and resolution of problems varied among RP crews, and that ZIP records did not reflect the condition of leaking valves identified by RP and NAP. During walkdowns in March and April 1996, NAP noted improvements in contamination control.

The inspector determined that the licensee had established programs to address leakage in the RCA to prevent the spread of contamination. Additionally, prior to this inspection, the licensee had recognized weaknesses in the implementation of these programs and had implemented corrective actions. However, the valves with leakage were in accessible areas of the RCA, there was sufficient prior knowledge of deficiencies, and the leakage was significantly developed to be clearly visible. The inspector concluded it was reasonable to expect that the licensee identify the contaminated areas prior to the NRC tours.

Procedure 75RP-ORP01 required that areas identified as having contamination levels greater than 1000 dpm/100cm^2 be posted with radiation warning sign(s) bearing the words: "Caution, Contaminated Area." The inspector concluded that the three examples of unposted contaminated areas represented a violation (528,529/96007-09).

c. Conclusions

One violation was identified for failure to follow procedure. The inspector concluded that the three examples of improper posting and inadequate contamination control reflected poor performance of the licensee's program for the control of contaminated areas in that routine tours by RP, maintenance, and operations personnel had not been effective in identifying leaking components which had inadequate contamination controls.

P8 Miscellaneous Emergency Preparedness Issues (92904)

P8.1 (Closed) Violation 529/94019-01: failure to classify unusual event. On May 3, 1994, the licensee telephonically notified the NRC Headquarters Operations Officer that an unusual event had occurred at the site at 2:45 p.m., on March 12, 1994. The licensee indicated an Unusual Event should have been declared at the time of the event due to the manual start of a third charging pump to recover pressurizer level while

drawing the bubble (NRC Event 26773). The event was reviewed by the resident inspectors (NRC Inspection Report 50-528;529;530/94009).

The licensee indicated at a May 25, 1994, meeting with NRC inspectors that three corrective actions had been identified and initiated.

- The Director of Operations prepared a letter for all shift supervisors discussing the failure to consider and classify an event. The letter reviewed the event and emphasized the failure at the time of the event to "evaluate this incident with emergency action levels in mind" and indicated that "a classification at the Notification of Unusual Event level would have been appropriate."

- Training in the nuclear management and resources council emergency action level scheme for the site was prepared for immediate training of emergency response personnel and for immediate implementation upon approval by the NRC. The licensee nuclear management and resources council emergency action levels were subsequently found acceptable by the NRC and the appropriate training was conducted.

- The Manager, Operations Training, indicated at the exit interview that training "Lessons Learned" regarding this and similar events had been added to the Operations Training program.

The inspectors determined during the May 1994 emergency preparedness inspection that appropriate corrective actions had been implemented to preclude recurrence of this type event. Two subsequent emergency preparedness inspections at the site, the 1995 annual emergency exercise (Inspection Report 50-528;529;530/95004) and a routine emergency preparedness inspection (NRC Inspection Report 50-528;529;530/95022) observed demonstrations of assessment of plant conditions and classification of emergency events by the licensee. The classification performance in the annual exercise was characterized as good and in the control room walkthrough scenarios, during the routine inspection as generally good. No failures to appropriately classify emergency events have occurred in the two years since this event.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on April 16, 1996. The licensee acknowledged the findings presented.

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

PARTIAL LIST OF PERSONS CONTACTED

Licensee

W. Stewart, Executive Vice President, Nuclear
R. Flood, Department Leader, System Engineering
J. Hesser, Director, Nuclear Engineering
W. Ide, Director, Operations
L. Johnson, Department Leader, Chemistry
A. Krainik, Department Leader, Nuclear Regulatory Affairs
J. Levine, Vice President, Nuclear Production
D. Mauldin, Director, Maintenance
J. McDonald, Director, Communications
G. Overbeck, Vice President, Nuclear Support
M. Shea, Director, Radiation Protection
D. Smith, Director, Outage
E. Sterling, Department Leader, Nuclear Assurance-Operations

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 61726: Surveillance Observations
IP 62703: Maintenance Observations
IP 71707: Plant Operations
IP 71711: Restart From Refueling
IP 71750: Plant Support Activities
IP 92712: In-office LER Review
IP 92901: Followup - Operations
IP 92903: Followup - Engineering
IP 92904: Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-529/96007-01	VIO	failure to adhere to procedure requirements
50-528;529;530/96007-02	NCV	failure to meet surveillance requirement 4.5.2.d.2
50-528;529;530/96007-03	IFI	review of resolution of UFSAR inconsistencies for SFP and testing of trisodium phosphate
50-530/96007-04	NCV	failure to follow procedure for blocking open controlled doors
50-528/96007-05	NCV	surveillance requirement 4.8.4.1 not fully met
50-528/96007-06	NCV	containment spray technical specification violation due to unrecognized valve failure
50-529/96007-07	NCV	technical specification violation due to missed surveillance requirement
50-528/96007-08	NCV	failure to follow chemistry procedure
50-528;529/96007-09	VIO	failure to maintain required contamination controls

Closed

50-529/94007	LER	momentary entry into technical specification 3.0.3
50-528/94001-01	LER	surveillance requirement 4.8.4.1 not fully met
50-529/95004	LER	technical specification violation due to missed surveillance
50-529/94005-01	LER	high pressure safety injection motor operated valve failed to open during ASME section XI testing
50-530/9412-03	VIO	failure to take action required by technical specification
50-529/9419-01	VIO	failure to classify unusual event
50-528/95016	LER	containment spray technical specification violation due to unrecognized valve failure

50-528;529;530/96007-02	NCV	failure to meet surveillance requirement 4.5.2.d.2
50-530/96007-04	NCV	failure to follow procedure for blocking open controlled doors
50-528/96007-05	NCV	surveillance requirement 4.8.4.1 not fully met
50-528/96007-06	NCV	containment spray technical specification violation due to unrecognized valve failure
50-529/96007-07	NCV	technical specification violation due to missed surveillance requirement
50-528/96007-08	NCV	failure to follow chemistry procedure

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
AT&T	American Telephone and Telegraph
CEA	Control Element Assembly
CRDR	Condition Report/Disposition Request
HVAC	Heating Ventilation and Air Conditioning
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LPSI	Low Pressure Safety Injection
PCM	Percent Millirho
RCA	Radiological Control Area
RP	Radiation Protection
SFP	Spent Fuel Pool
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report