U.S. NUCLEAR REGULATORY COMMISSION
REGION V

Report No. 50-206/86-36, 50-361/86-24, 50-362/86-23

Docket No. 50-206, 50-361, 50-362

License No. DPR-1, NPF-10, NPF-15

Licensee: Southern California Edison Company
P. O. Box 800, 2244 Walnut Grove Avenue
Rosemead, California 92770

Facility Name: San Onofre Units 1, 2 and 3

Inspection at: San Onofre, San Clemente, California

Inspection conducted: Unit 1 - July 26 through August 15, 1986
Unit 2/3 - June 28 through August 15, 1986

Inspectors: PH Johnson 9/3/86
for F. R. Huey, Senior Resident Inspector, Units 1, 2 and 3 — Date Signed

PH Johnson 9/3/86
for J. P. Stewart, Resident Inspector — Date Signed

PH Johnson 9/3/86
for A. D'Angelo, Resident Inspector — Date Signed

PH Johnson 9/3/86
for J. E. Tatum, Resident Inspector — Date Signed

PH Johnson 9/3/86
for R. C. Tang, Resident Inspector — Date Signed

Approved By: PH Johnson 9/3/86
P. H. Johnson, Chief
Reactor Projects Section 3 — Date Signed

Inspection Summary

Inspection on July 26 through August 15, 1986 (Report No. 50-206/86-36) and June 28 through August 15, 1986 (Report No. 50-361/86-24 and 50-362/86-23)

Areas Inspected: Routine resident inspection of Unit 1 Operations Program including the following areas: operational safety verification, evaluation of plant trips and events, monthly surveillance activities, monthly maintenance activities, engineered safety feature system walkdown, refueling activities, independent inspection, and licensee events report review. Inspection Procedures 30703, 61726, 62703, 71707, 71710, 71711, 92701, 93702, 93701, 62700, 82301, and 90712 were covered.

Results: Of the areas examined, no violations or deviations were identified.

DETAILS

1. Persons Contacted

Southern California Edison Company

H. Ray, Vice President, Site Manager
*G. Morgan, Station Manager
*M. Wharton, Deputy Station Manager
*D. Schone, Quality Assurance Manager
D. Stonecipher, Quality Control Manager
R. Krieger, Operations Manager
D. Shull, Maintenance Manager
J. Reilly, Technical Manager
*P. Knapp, Health Physics Manager
B. Zintl, Compliance Manager
D. Peacor, Emergency Preparedness Manager
P. Eller, Security Manager
J. Reeder, Operations Superintendent, Unit 1
H. Merten, Maintenance Manager, Unit 1
T. Mackey, Compliance Supervisor
*C. Couser, Compliance Engineer

San Diego Gas & Electric Company

R. Erickson, San Diego Gas and Electric

*Denotes those attending the exit meeting on August 15, 1986.

The inspectors also contacted other licensee employees during the course of the inspection, including operations shift superintendents, control room supervisors, control room operators, QA and QC engineers, compliance engineers, maintenance craftsmen, and health physics engineers and technicians.

2. Operational Safety Verification (Units 2/3)

The inspectors performed several plant tours and verified the operability of selected emergency systems, reviewed the tag out log and verified proper return to service of affected components. Particular attention was given to housekeeping, examination for potential fire hazards, fluid leaks, excessive vibration, and verification that maintenance requests had been initiated for equipment in need of maintenance.

On July 9 and 10, 1986, the inspector observed the Unit 2/3 pre-shift briefing. On July 16, the inspector observed the control room turnover between the swing and graveyard shifts. Briefings by the outgoing staff appeared to be detailed and informative.

No deviations or violations were identified.

3. Evaluation of Plant Trips and Events

a. Unit 1 (Period June 28 to July 26, 1986 Covered in Inspection Report 86-35)

On July 26, 1986, Unit 1 reentered Mode 1 after completing repairs to the turbine generator voltage regulator and the turbine speed control system. Unit 1 was synchronized to the grid at 1843 on July 26, 1986.

Emergency Feedwater Actuation Signal (EFAS) on July 29, 1986

At 1935, with Unit 1 at 76% power, the main steam flow signal to the steam generator level control system momentarily failed. This failure resulted in a rapid reduction in steam generator level and the initiation of an EFAS. The reactor operators took manual control of the feedwater system and reduced turbine load to approximately 63% power during the transient. The operators stabilized the water level in the steam generators and returned the steam generator feed control system (FCS) to automatic at 2005 with reactor power at 65%. The licensee initiated troubleshooting of main steam pressure transmitter (PT) 459, suspected as the possible cause for the loss of the main steam flow signal.

Unusual Event on July 30, 1986

At 0104 on July 30,1986, with reactor power at 65%, the main steam flow signals to the FCS failed low and the reactor operators took manual control of the FCS. It was determined that PT-459 (which provides steam density compensation for the calculation of steam flow) had failed low and this caused all three steam/feedwater flow mismatch trips in the reactor protection system to become inoperable. At 0104, the licensee entered Technical Specification (TS) action statement 3.0.3 due to the loss of the reactor protection system trip function. At 0201, the shutdown required by TS 3.0.3 was initiated and at 0203, an Unusual Event was declared by the licensee. At 0350, the repair of PT-459 had been completed and the steam/feedwater flow mismatch protection function had been restored. At 0350, the Unusual Event was terminated with the reactor power at 30%. The licensee initiated an increase in power at 0515 to continue Power Physics Testing following the refueling and modification outage.

Power Reductions due to Condenser Saltwater Leaks on July 30 and 31, 1986

At 1341 on July 30, 1986, a reactor power reduction was made to repair a salt water leak in the number 2 water box. Three leaking tubes were repaired. A loss of vacuum occurred during the power reduction which further reduced power (temporarily) to 20%.

At 1100 on July 31, 1986, a reactor power reduction was initiated to enter Mode 2 for the purpose of repairing condenser saltwater leakage. Repairs were made to the number 2 condenser waterbox tube sheet epoxy.

Steam Generator Wide Range Level Transmitter Repair - Mode 2 Entry on August 2, 1986

At 2200 on August 1, 1986, a reactor power reduction was initiated to enter Mode 2 so that a containment entry could be made to repair the "C" steam generator wide range level transmitter. Repair of the transmitter was required by the plant Technical Specifications (the transmitter is part of the emergency feedwater system instrumentation). The unit was synchronized to the grid at 2202 on August 2, 1986.

Reactor Trip on August 5, 1986

At 0245 on August 5, 1986, with reactor power at 87%, the reactor tripped as a result of a turbine load rejection. This load rejection occurred due to a failure in the turbine governor control system causing the turbine control valves to close. The licensee conducted an investigation, with the assistance of a Westinghouse turbine engineer, and was unable to determine the cause of the failure.

Ground on a Safety Injection Valve Control System - Return to Mode 3 on August 5, 1986

At 2302 on August 5, 1986, the reactor was returned to Mode 3 from Mode 2 as a precautionary measure, while troubleshooting a 125 V DC ground on the control system for safety injection system control valve FCV1112. The reactor had previously entered Mode 2 and had achieved criticality at 2151 (about one hour earlier).

Power Reduction Due to Safety Injection Recirculation Valve CV-875B Failure on August 8, 1986

At 1936 on August 8, 1986, with reactor power at 50%, a power reduction was initiated when safety injection recirculation valve, CV-875B, mechanically failed open. The valve shaft separated from the operator which allowed feedwater system pressure to force the valve open. As a result, feedwater flow was redirected to the refueling water storage tank (RWST) since the feedwater pump also functions as the safety injection pump. The repair of the valve required securing the west feedwater pump because the valve is unisolable from the discharge of the pump. Reactor power was reduced to approximately 20% in order to initiate repair of CV-875B.

Containment Sump Level Increase While Recirculating the Refueling Water Storage Tank - Mode 2 Entry on August 9, 1986

On August 9, 1986, at 0453, the unit entered Mode 2 so that licensee personnel could investigate containment conditions when it was noted that the containment sump level increased while recirculating the RWST. The licensee determined that the sump level increase was due to leakage past containment spray header isolation valve CV-114 with the spray header pressurized. This occurred while recirculating the RWST water with a refueling water pump. The amount of RWST water which leaked into containment was approximately 1500 gallons over a one hour period. The licensee's inspection and cleanup did not identify any damage and the unit was returned to Mode 1 at 2302 on August 9, 1986.

b. Unit 2

Reactor Trip of July 7, 1986 (Unit 2)

At 1408 on July 7, 1986, while at 49% power, the reactor tripped after 12 days of continuous operation. The contributing causes to the reactor trip and the circumstances surrounding it are summarized below.

At approximately 1008 on July 7, 1986, control element assembly (CEA) No. 55 dropped to the bottom of the core. Investigations revealed that 2 of 3 silicon controlled rectifiers (SCRs) in the control element drive mechanism control system (CEDMCS) for this CEA failed due to an increase in temperature in the CEDMCS room. The temperature increased from the normal $70^{o}F$ to $85^{o}F$ due to a failure of the air conditioning units in the room. The temperature surrounding the SCRs inside the CEDMCS cabinets was estimated to be $130^{o}F$. (These SCRs receive power from the CEA drive motor generator set, via the reactor trip breaker switchgear which converts AC power to DC power for the magnetic coils in the CEDM.) CEA No. 55 could not be recovered and at 1018 a power reduction was initiated per Technical Specification 3/4.1.3. At 1208, power was further reduced to 49% due to high azimuthal power tilt (Technical Specification 3/4.2.3). At 1408, after the failed SCRs associated with CEA No. 55 were replaced, CEA No. 49 dropped into the core. This occurred before CEA No. 55 was returned to service. As soon as CEA No. 49 dropped, the reactor tripped on low departure from nucleate boiling ratio (DNBR) and high local power density due to the additional penalty factor generated by the core protection calculators (CPCs). It was later determined that the upper and lower Hall Effect sensors (sensors for monitoring current supplied to the CEDM gripper coils) for CEA No. 49 had failed. These sensors were later replaced.

During efforts to start up the reactor on July 10, unrelated problems were encountered with the automatic sequential withdrawal of the CEAs. The problems were attributed to a defective control switch in the control circuit, which was corrected. No additional problems were identified and the reactor was taken critical at 1250 on July 10.

From the time the first CEA dropped (No. 55), the licensee took appropriate actions to recover the rod and to commence power reduction as required by the Technical Specifications. For post trip followup action, the licensee performed CEA grooming (coil traces of the CEDM) of all CEAs which identified minor problems in some CEDMs. These problems were promptly corrected by the licensee.

During the recent Unit 2 Cycle 3 refueling outage, the licensee replaced CEA timer cards with automatic CEDM timing modules (ACTMs) in the CEDMCS of all 91 CEAs. The Hall Effect sensors mentioned above are part of the ACTM. The intent in using this ACTM design was to improve CEDM performance and minimize inadvertent rod drops. The licensee is currently working with the vendor, Combustion Engineering, to explore ways of eliminating possible ACTM software and hardware problems.

Reactor Trip on July 14, 1986 (Unit 2)

On July 14, 1986, at 0858, the unit tripped from 100% power while the licensee was conducting reactor plant protection system (RPPS) logic matrix functional testing associated with the containment isolation actuation signal (CIAS). The licensee had completed functional testing of trip path 1 and was testing trip path 2, when a CIAS was received on trip path 1. The "two out of four logic" for containment isolation was satisified which caused the main steam isolation valves (MSIVs) and the main feedwater isolation valves (MFIVs) to shut. This resulted in a CPC auxiliary reactor trip on high pressurizer pressure. When the licensee tried to reset the CIAS, one relay did not reset initially but did reset while troubleshooting. The licensee examined the relay, found that the contacts were slightly pitted, and concluded that this had caused the failure. The relay contacts were subsequently refurbished without performance of any failure testing. As a result, the failure mechanism could not be demonstrated. The relay involved was a Potter and Brumfield KR3DH relay with twin silver-cadmium oxide contacts rated for 20 amps at 120 volts AC, 60 Hertz (resistive).

Reactor Trip on August 12, 1986 (Unit 2)

On August 12, 1986, at 1330, the reactor tripped from 100% power. Prior to the event, main steam isolation signal (MSIS) logic matrix testing in the reactor plant protection system (RPPS) was being conducted. Licensee personnel had reset trip path 3 after completion of testing and had just commenced testing of trip path 4 when a trip signal was received on trip path 3. This satisfied the MSIS logic and the main steam isolation valves (MSIVs) shut. As a result of the loss of the secondary heat sink, the CPCs tripped the reactor on high pressurizer pressure. The licensee conducted subsequent testing of the RPPS, but the root cause for the MSIS could not be identified. A similar problem was encountered during the previous RPPS surveillance testing that was conducted on July 14, 1986 (see previous paragraph). The unit was returned to service on August 14, 1986.

Transients Due to CEA Drops (Unit 2)

On July 25, 1986, at 1603, power was reduced to 87% when CEA 83 dropped into the core. The CEA, a shutdown CEA, was later recovered and unit power was returned to 98% at 2350 on the same day. Unit power was held at 98% for a scheduled moderator temperature coefficient surveillance. Prior to the CEA drop, a "CEDMCS Timer

Failure" alarm was received in the control room. As a result, the licensee commenced troubleshooting in the CEDMCS room to determine the cause of this alarm. During the troubleshooting, the RESET button was depressed while CEA 83 was on the upper gripper. At this time, CEA 83 dropped. It was noted that depressing the RESET button should clear the logic circuitry but should not cause any CEA movement. The ACTM card for CEA 83 was tested and reinstalled since no problems could be found. The licensee considered this a "non-reproducible failure mechanism."

On July 29, 1986, at 2259, unit power was reduced to 82% when CEA 44 dropped into the core. The CEA was recovered and unit power was returned to 100% at 0420 on July 30, 1986. The CEA drop apparently occurred while the licensee was responding to a "CEDMCS Timer Failure" alarm in the control room. Abnormal voltage was indicated in the CEDMCS room for CEAs 44, 45, and 46 which are all regulating CEAs in subgroup 11. All three CEAs were on the upper gripper at the time. The licensee concluded that the Hall Effect sensors on these CEAs were faulty, which was possibly due to excessive heat in the CEDMCS cabinet. These sensors were replaced and CEA 44 was recovered.

On July 31, 1986, at 1050, unit power was reduced to 70% when CEA 45 dropped into the core. CEA 45 was withdrawn at 1240 after the licensee replaced the ACTM card with the old CEA timer card. Unit power was then restored to 100% at 1600 that day. The licensee concluded that the CEA drop had been caused by higher than normal resistance across the fuse which supplies power to the logic for subgroup 11. This caused an excessive voltage drop across the Hall Effect sensors in the ACTM card and resulted in the CEA drop. The fuse was replaced but a low voltage condition was still indicated. The licensee installed a temporary jumper from a spare fuse and plans to further investigate the problem during next outage.

From July 31 until the end of the reporting period (August 15), Unit 2 did not experience any more CEA drops.

c. Unit 3

Reactor Trip on July 26, 1986 (Unit 3)

On July 26, 1986, the reactor was manually tripped from 77% power when the main feedwater pumps automatically tripped due to loss of suction pressure. The licensee had reduced reactor power to 80% so that one quadrant of the main condenser could be isolated for cleaning. While in this configuration, a saltwater leak developed in another quadrant of the condenser. The system automatically started to dump this condensate and add clean makeup water. Since the rate of automatic condensate make-up was less than the dump rate, suction pressure dropped and the feedwater pumps tripped. The saltwater leak was repaired and the unit was returned to service on July 27, 1986.

Miscellaneous Load Reductions (Unit 3)

At 2000, on July 28, 1986, reactor power was reduced to 18% in order to make repairs to the hydraulic dump valve associated with main feedwater block valve 3HV-4051. Repairs were completed on July 29, 1986.

On August 5, 1986, power was reduced to 80% in order to isolate and clean the north east condenser waterbox. While operating in this configuration, a saltwater leak developed in the north west condenser. In this case, reactor operators were cognizant of the situation, due to a similar occurrence on July 16, 1986 (paragraph 3c), and reactor power was reduced to 62% to prevent the main feedwater pumps from tripping on low suction pressure until the north east quadrant could be returned to service. Unit power was restored to 100% on August 7, 1986.

No violations or deviations were identified.

4. Monthly Surveillance Activities

a. 31-Day Surveillance on Remote Instrumentation (Unit 2)

During this inspection period, the inspector observed portions of the remote shutdown instrumentation 31-day surveillance required by Unit 2 Technical Specification 4.3.3.5. As observed, the surveillance was conducted in accordance with procedure SO23-3-3.28, TCN 6-13.

b. 31-Day Surveillance on Auxiliary Feedwater System (Unit 2)

The inspector observed portions of the auxiliary feedwater system valve position verification which is conducted every 31 days. The purpose of this surveillance is to demonstrate the operability of the auxiliary feedwater system as required by Technical Specifications 4.7.1.2.1.a.2. and 4.7.1.2.1.a.3. The surveillance, as observed, was performed in accordance with procedure SO 23-3-3.16, TCN 6-12.

c. Shiftly Surveillance (Units 2 and 3)

The inspector observed portions of the shiftly surveillance (channel check) conducted on certain liquid and gaseous effluent area radiation monitors for Units 2 and 3. These area monitors are required to be tested by the Technical Specifications. The surveillance, as observed, was conducted in accordance with procedure SO23-3-3.21 and the tested monitors were demonstrated operable.

d. Weekly Surveillance (Unit 3)

The inspector observed portions of the Unit 3 weekly surveillance conducted by the licensee. This surveillance included verification of borated water source availability (Technical Specification

4.1.2.8.a.2 and 4.5.5.a.1), verification of fire water storage tank volume (Technical Specification 4.7.8.1.1.a), and source check of radiation monitors (Technical Specification 4.3.38 Table 4.3-8 and 4.3.3.9 Table 4.3-9). The portions observed were performed in accordance with procedure S03-3-3.27, TCN 2-12.

No violations or deviations were identified.

5. Monthly Maintenance Activities

a. Motor Driven Auxiliary Feedwater Pump (2P141) (Unit 2)

The licensee identified oil leaks on the motor bearings and packing leaks on the inboard pump bearings of motor driven auxiliary feedwater pump (AFWP) 2P141. These problems were corrected by the licensee during this inspection period. The inspector observed the final adjustment of the pump packings by maintenance personnel as part of the effort to return the pump to service. Both operations and quality control personnel were present during this effort.

b. Drain Valve S21305MR422 (Unit 2)

The inspector observed part of the licensee's effort to repair valve S21305MR422 which is a drain valve located in the discharge path of AFWP 2P141. The licensee had identified a water leak through the valve seat. The inspector observed that maintenance personnel followed the requirements specified in Station Maintenance Procedure S0123-I-6.12 and the instructions detailed in the Maintenance Order (MO 86031056000). The inspector also noted that the QC holdpoint was properly maintained.

c. Steam Driven Auxiliary Feedwater Pump Check Valve (Units 2 and 3)

As discussed previously in report 50-361/86-19 paragraph 5b, the licensee conducted inspections of check valves 1301-MU-003 and 1301-MU-005 on Unit 2, and check valve 1301-MU-003 on Unit 3. These check valves are in the steam supply piping to the steam driven auxiliary feedwater pump, and each one is supplied by a separate steam header.

After the check valves were inspected and repaired on Unit 2, the licensee discovered that check valve 1301-MU-005 was making a loud rattling noise. The licensee disassembled MU-005 to determine the cause for the noise, and found that a dowel pin, which is used to stake the hinge pin, had been sheared off. The dowell pin was replaced, but it did not correct the rattling noise. The licensee believes that the noise is due to a resonant condition, and has closed valve 2HV-8201 to isolate steam to MU-005. Valve 2HV-8201 will automatically open upon receipt of an emergency feedwater actuation signal (EFAS), and the system remained operable. The licensee plans to correct the resonant condition during the next Unit 2 outage.

During this report period, the licensee inspected check valve 1301-MU-005, which completes the check valve inspection for the Unit 3 steam driven auxiliary feedwater pump. The hinge pins were found to be degraded, and they were replaced with hinge pins that have a stellite inlay for the wearing surface.

The inspector observed portions of these maintenance activities, and found that they were conducted in accordance with the approved procedures.

No violations or deviations were identified.

6. Engineered Safety Feature Walkdown (Unit 2) Boric Acid Flowpath/Emergency Boration/Charging Sytem

During the inspection period, the inspector performed walkdowns of the Unit 2 boric acid flowpath and the emergency boration portion of the charging system. The system was found to be in the alignment required by Technical Specifications (Sections 3.1.2.2, 3.1.2.4, 3.1.2.6, 3.1.2.8) and Station Procedure (SO23-3-3.1) as applicable to the current operating mode (Mode 1). In addition, all required ESF locks for the manual valves were found to be in place and properly locked.

Cleanliness and housekeeping of the boric acid flowpaths and surrounding areas was also inspected. The condition of the boric acid makeup (BAMU) tank room was less than satisfactory. The inspector noticed large chunks of boric acid crystals around the BAMU tanks and on the tank outlet valves. In addition, unused paper clips, piping insulation clamps, heat trace, insulation material, and other debris were scattered around the tanks and tank level transmitter (LT) 206. The inspector noted that no one was working in the room at the time. These conditions were identified to the licensee for resolution.

While checking the position of charging header isolation valves S2/208MU091 and S2/208MU084 in the 30 foot elevation penetration area ("the Jailhouse"), the inspector noticed water dripping from an overhead valve. In addition, approximately 1 cubic meter of water had accumulated on the floor of the room due to leakage from various other valves. The valve drip, that was the source of concern, came from the cap of valve S2/208MR163 which is the vent valve from the 2 inch line between (downstream of) the charging pump and charging header isolation valve S2/208MU091. The inspector noted that a deficiency tag had been hung on the leaking valve but no bag had been placed below the valve to catch the leaking water. The HP foreman, upon finding this, immediately placed a plastic bag around the valve to catch the leakage and modified the HP sign outside the room to require lab coats to be worn. Previously, only boots and gloves were required. The inspector also informed the plant operator of the condition in the room.

No violations or deviations were identified.

7. Refueling Activities

During this inspection period, refueling activities were completed and power physics acceptance testing was accomplished for Unit 1 on August 12, 1986.

No violations or deviations were identified.

8. Independent Inspection

a. Allegation Concerning Valve 3HCV-6459 (RV-86-A-007)

(1) Characterization

An allegation was received which stated that the gear box casing for valve 3HCV-6459 was dropped and cracked while the valve was undergoing repairs. The alleger was concerned that the cracked gear casing may have been repaired with metal putty and then painted over so the crack would not be noticed.

(2) Implied Significance to Design, Construction or Operation

The cracked gear casing could possibly render the valve inoperable when called upon to function.

(3) Assessment of Safety Significance

Valve 3HCV-6459 is located in the A train of the saltwater cooling system (SWC), and is used to backflush component cooling water (CCW) heat exchanger E-001. The valve is manually operated and serves its safety function in the closed position. Since the valve is normally closed and the gear box does not have to function to satisfy the safety requirement, the gear box is not safety related.

The inspector examined the gear box on 3HCV-6459, and found no evidence of damage. The inspector discussed this allegation with the licensee, and the licensee conducted a search through their nonconformance reports (NCRs) and found that a similar valve, 3HCV-6458, had a cracked gear casing. 3HCV-6458 is used to backflush CCW heat exchanger E-002. The inspector examined the valve and reviewed the NCR (3F-0078). The gear box casing was cracked, but the safety function of the valve was not affected and the deficient condition had been properly identified and dispositioned by the licensee.

(4) Staff Position

The cracked gearbox casing on valve 3HCV-6458 does not impair the safety function of the valve. This allegation is closed.

(5) Action Required

None.

b. Design Change Review

During the Unit 2 refueling outage, the licensee replaced the existing reactor coolant pump (RCP) seals with a newly designed seal provided by Bingham-Willamette Company. The newly designed seals appeared to be functioning as anticipated with the exception that the controlled bleed-off temperature for RCP-34 was approximately 180°F, which is about 30°F higher than for the other pumps. The design called for 100°F to 140°F. Several reactor trips occurred after the design change was completed and the seals functioned as required. The inspector completed a review of design change package (DCP) 6025.OSM, which implemented the RCP seal replacement, and verified that the change was conducted in accordance with the licensee's procedures.

No violations or deviations were identified.

9. Review of Licensee Event Reports

The following Licensee Event Reports (LERs) were closed on the basis of in-office review.

Unit 1

(Closed) Licensee Event Report 85-17, Rev. 1, Further Information on Feedwater Hammer Event

This item indicated that further information on the feedwater hammer event would be provided to the NRC. It is closed based on the receipt of this information as part of the SONGS Unit 1 Restart Program.

Unit 2

a. (Closed) Licensee Event Report 84-77, Control Room Isolation System Actuation Due to Error

The licensee reported that a Control Room Isolation System (CRIS) actuation occurred as a result of the failure of an instrumentation and control technician to fully depress the CRIS reset switch as required by the surveillance procedure he was using. The licensee indicated that for corrective action, a design change would be completed to install a keylock switch for the bypass function and a spring loaded switch for the reset function to minimize the possibility of further CRIS actuations. Based on this proposed design change, this item is closed.

b. <u>(Closed) Licensee Event Report 85-01, Missed Fire Watch</u>

This report indicated that a routine roving fire watch missed a tour of an electrical tunnel which was required by Technical Specifications. The licensee reported that the cause of the event was inadequate prior planning of a security computer outage, and a failure of personnel to implement a revised access routing for the firewatch. The licensee indicated that the corrective actions taken, to prevent recurrence of this event, included authorization of firewatches to enter vital areas during contingencies when security officers are not available. Based on the licensee's corrective actions, this item is closed.

c. <u>(Closed) Licensee Event Report 86-03, Control Room Isolation System Actuation</u>

The licensee reported that one train of the CRIS actuated as a result of the failure of a capacitor in a radiation monitor power supply. The power supply was repaired as corrective action. Based on this corrective action, this item is closed.

d. <u>(Closed) Licensee Event Report 86-08, Containment Audible Monitor Inoperable During Mode 6</u>

This report indicated that the source range neutron flux monitor audible speaker, located in containment, failed prior to entry into Mode 6. However, the reactor was taken into Mode 6 contrary to Technical Specification Limiting Condition for Operation 3.0.4. The cause of this event was reported to be the lack of explicit procedural requirements to sufficiently ensure that all Mode 6 surveillances were performed prior to entering the Mode. The licensee indicated that corrective actions were performed to revise the Mode 6 entry controlling procedure to explicitly require review of each surveillance requirement (for completion) prior to the Mode entry. Based on these corrective actions, this item is closed.

e. <u>(Closed) Licensee Event Report 86-09, Turbine Driven Auxiliary Feedwater Pump Steam Supply Check Valve Damage</u>

This report, which was supplied for information only, gave an update on status of the turbine driven auxiliary feedwater pump steam supply check valves which had received substantial damage due to steam erosion. The licensee reported that, for corrective action, a design change was implemented for the affected check valves. This change incorporated the use of stellite sleeves in the hinge pin seating surface for the valves. These sleeves were added to ensure that excessive wear does not develop between refueling outages at which time they can be inspected for wear. Based on this design change, this item is closed.

f. (Closed) Licensee Event Report 86-11, Spurious Containment Purge Isolation System Actuation

This report indicated that a Containment Purge Isolation System (CPIS) actuation occurred as a result of a signal from an area radiation monitor. The cause of the area radiation monitor alarm was the result of spurious electrical noise. The licensee implemented corrective actions to reduce the possibility of spurious CPIS actuations as indicated in LER 85-56. These corrective actions consisted of replacing the detector and ensuring its proper grounding. Since this is the first CPIS since implementation of these corrective actions, this item is closed.

g. (Closed) Licensee Event Report 86-15, Reactor Trip Due to Shorted Capacitor in a 1E Inverter

The licensee reported that a reactor trip occurred as a result of the failure of a capacitor in a vital inverter while another vital inverter was out of service for testing. This resulted in two control element assembly calculators (CEAC's) being inoperable at the same time. The licensee indicated that the possibility of the failure of a capacitor resulting in inoperability of one CEAC with the other CEAC out of service is very remote. Due to the fact that this is an isolated occurrence, this item is closed.

h. (Closed) Licensee Event Report 86-21, Spurious Fuel Handling Isolation System Actuation

The licensee reported that a spurious fuel handling isolation system (FHIS) actuation occurred when an airborne monitor alarmed as a result of random electrical noise. The licensee also indicated that corrective action (replacement of the detector and verification of proper grounding) had been taken to minimize the possibility of further spurious actuations. Based on this corrective action, this item is closed.

Unit 3

a. (Closed) Licensee Event Report 86-05, Turbine Trip, Reactor Trip Due to Voltage Spike on Non-1E Instrument Bus

This item was submitted to report that a turbine trip - reactor trip occurred as a result of a voltage transient on one phase of the non-1E uninterruptible power supply inverter. This inverter supplies power to two auxiliary relays associated with the control element drive mechanism undervoltage relays in the turbine trip circuitry. For corrective action, the licensee indicated that a design change, similar to that implemented in Unit 2, was performed in Unit 3. The design change rearranged the auxilary relays so that a single phase voltage transient will not cause a turbine trip. Based on this design change, this item is closed.

b. <u>(Closed) Licensee Event Report 86-09, Turbine Driven Auxiliary Feedwater Pump Steam Supply Check Valve Damage</u>

This report, which was supplied for information only, gave an update on status of the turbine driven auxiliary feedwater pump steam supply check valves which had received substantial damage due to steam erosion. This item is similar to LER 86-09 for Unit 2. The same design change used in Unit 2 was implemented for the affected check valves in Unit 3. This change incorporated the use of stellite sleeves in the hinge pin seating surface for the valves. These sleeves were added to ensure that excessive wear does not develop between refueling outages at which time they can be inspected for wear. Based on this design change, this item is closed.

No violations or deviations were identified.

10. <u>Exit Meeting</u>

On August 15, 1986, an exit meeting was conducted with the licensee representatives identified in Paragraph 1. The inspectors summarized the inspection scope and findings as described in this report.