U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-206/86-37, 50-361/86-27, 50-362/86-25

Docket Nos. 50-206, 50-361, 50-362

License Nos. DPR-13, 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: August 16 through October 8, 1986

Inspectors: C.W. Caldwell FOR — 10/28/86
F. R. Huey, Senior Resident Inspector, Units 1, 2 and 3 — Date Signed

C.W. Caldwell FOR — 10/28/86
J. P. Stewart, Resident Inspector — Date Signed

C.W. Caldwell FOR — 10/28/86
J. E. Tatum, Resident Inspector — Date Signed

C.W. Caldwell FOR — 10/28/86
R. C. Tang, Resident Inspector — Date Signed

Approved By: C.W. Caldwell FOR — 10/28/86
P. H. Johnson, Chief
Reactor Projects Section 3 — Date Signed

Inspection Summary

Inspection on August 16 through October 8, 1986 (Report Nos. 50-206/86-37, 50-361/86-27, 50-362/86-25)

Areas Inspected: Routine resident inspection of Units 1, 2 and 3 Operations Program including the following areas: operational safety verification, evaluation of plant trips and events, monthly surveillance activities, monthly maintenance activities, independent inspection, licensee event report review, and follow-up of previously identified items. Inspection procedures 30703, 37910, 61726, 62700, 62703, 71707, 71710, 73051, 92701 and 93702 were covered.

Results: 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
W. Marsh, Operations Superintendent, Units 2/3
J. Reeder, Operations Superintendent, Unit 1
V. Fisher, Assistant Operations Superintendent, Units 2/3
B. Joyce, Maintenance Manager, Units 2/3
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 October 10, 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

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.

a. Housekeeping

During this inspection period the inspector observed that housekeeping had improved from previous periods. One weakness that was observed, however, involved evidence of cigarettes in non smoking areas. Two cigarette butts were found in a class 1E cable tray, and an appreciable number of cigarette butts were seen in other areas of the plant that are designated as non-smoking. The inspector emphasized this weakness at the exit interview. The licensee addressed current efforts to resolve this problem. The inspector will monitor progress during future inspections.

b. Unit 2 Reactor Startup

Following the September 13 spurious trip of Unit 2, the inspector observed the licensee post trip review effort and subsequent reactor plant startup conducted on September 14, 1986. The inspector noted the following deficiencies, which were reviewed with the plant operations manager:

(1) The shift technical advisor (STA) did not properly document the corrective actions implemented to preclude recurrence of the trip. These actions are required to be documented in section 2.4.2 of attachment 4 of procedure SO123-0-25 (post trip review). This omission was not corrected by the shift superintendent during his review of the form. It should be noted that the licensee had taken proper corrective actions and although the missing data from the post trip review form were of minor actual significance, it demonstrated a lack of rigorous implementation of corrective actions previously identified by the licensee (e.g., following the April 13, 1986 early criticality event on Unit 3, the licensee identified the need to ensure more rigorous documentation of all post trip review actions). The licensee agreed and stated that all cognizant operations personnel have been recounseled on the importance of proper documentation of all post trip review actions.

(2) Step 2.5.2 of procedure SO123-0-25 provided no acceptance criteria for determining proper operation of the reactor trip breakers. The licensee agreed that the addition of this criteria would improve the procedure and committed to revise it accordingly.

(3) Step 3.4.8.1 of procedure SO23-3-1.1 (reactor startup) required that the reactor operator confirm expected reactivity addition by ensuring that source range count rate increases in direct proportion to the positive reactivity inserted during withdrawal of shutdown and part length control rod groups. During the September 14 startup, the reactor operator verified this step, although source range count rate had less than doubled during a control rod withdrawal sequence that should have reduced reactor shutdown margin by a factor of three (e.g., source range count rate should have tripled). Review of this concern with the shift superintendent identified that although he recognized that count rate did not respond in direct proportion to shutdown group reactivity additions (due to excore detector geometry and core self shielding effects), he considered that the intent of the procedure was to ensure

proper source range instrument response more from a qualitative than quantitative standpoint. During discussion of this item with the inspector, the plant operations manager agreed that the importance of reactor startup and the difficulties experienced during the April 13th event, warrant additional procedure clarity with regard to the criteria for monitoring proper plant response. The licensee committed to revise this procedure accordingly.

(4) Plant operators were not fulfilling the intent of step 3.4.7 of procedure SO23-3-1.1, which requires use of an inverse count rate plot (1/M plot) for confirming proper plant response during approach to criticality evolutions. Following the April 13 early criticality event on Unit 3, licensee corrective actions included implementation of the requirement to perform a 1/M plot for all reactor startups. During the reactor plant startup on September 14th, plant operators performed a 1/M plot, however, none of the hold point estimated critical position (ECP) projections fell within the allowable ECP band (all projections fell beyond the all rods out (ARO) upper limit, indicating the need for primary boron dilution). A review of this concern with the STA and cognizant technical supervisor identified that similar situations have developed during previous reactor startups and in each case the shift superintendent selected the option in the procedure to continue rod withdrawal past the hold point even though ECP projections fell outside the allowable 1/M plot band. The inspector reviewed his concern with the plant operations manager that such an approach to use of a 1/M plot defeats the primary purpose for performing a 1/M plot. If all hold points result in ECP projections outside of the allowable band, the reactivity addition interval between hold points should be reduced to provide a meaningful ECP projection. The licensee agreed and committed to revise the procedure and retrain cognizant personnel accordingly.

No violations or deviations were identified.

3. Evaluation of Plant Trips and Events

a. Reactor Trip on September 4, 1986 (Unit 3)

The reactor tripped from 90% power on September 4, 1986, when the turbine trip solenoid valves were deenergized causing a turbine trip. The reactor subsequently tripped due to loss of load. An equipment operator was closing DC breaker 3D507 to connect non 1E bus 3B5 to the spare charger and, as the breaker closed, the operator inadvertently tripped DC breaker 3D506 which was supplying power to the turbine control system. The operator was not using the proper tool to operate the breaker, and evidently his hand slipped off when the breaker snapped into position. The licensee instructed the operators to use the proper tools when operating breakers. The unit was returned to power operation on September 6, 1986.

b. Feedwater Pump Failure on September 4, 1986 (Unit 1)

At 2142 on September 4, 1986 with reactor power at 52%, the West Main Feedwater Pump (MFP) low lube oil pressure alarm come in and operators immediately inspected the pump and declared the pump inoperable at 2145. The MFP also serves as a safety injection pump and a reactor shutdown was initialed at 2235 as required by the plant Technical Specifications. An Unusual Event was declared at this time in accordance with the Emergency Plan.

Licensee Event Report 86-011 describes the cause of the MFP shaft failure and corrective action. Unit 1 remained out of service until 1507 on October 1, 1986, to repair the West MFP and other equipment deficiencies identified while performing maintenance activities during the outage.

c. Reactor Trip on September 13, 1986 (Unit 2)

At 0952 on September 13, 1986, Unit 2 tripped from 60% power due to a spurious position indication signal from Control Element Assembly (CEA) 34. This occurred when, during movement of part length CEA group 1, an erratic position indication signal from CEA 34 to Control Element Assembly Calculator (CEAC) 1 caused generation of penalty factors to the Core Protection Calculator (CPC) Departure from Nucleate Boiling Ratio (DNBR) and Local Power Density (LPD) calculations, resulting in the generation of a reactor trip signal by all four CPCs.

The Reed Switch Position Transmitter for CEA 34 was found to be defective and was replaced. The unit was returned to full power at 0215 on September 15, 1986.

The above reactor trip occurred when the reactor protection system conservatively applies the penalty factors from a single CEAC to all CPC channels even though both CEACs were in service. The licensee is currently working with the vendor, Combustion Engineering, in developing means to prevent single train CEAC output to the CPCs from causing reactor trips.

d. Unit Shutdown On September 30, 1986 (Unit 3)

At 0201 on September 30, 1986, the unit was removed from service to replace the reactor coolant pump (RCP) seals. The seals had been degrading on pumps 1 and 3, and the controlled bleed off flow was exceeding 3.5 gpm with a controlled bleed off temperature approaching 170°F. The inspector observed that the reactor shutdown was well controlled and occurred without incident. The licensee plans to install Bingham-Willamette seals in an effort to resolve the problem of repetitive failures of the original seals. These seals have already been installed on the Unit 2 RCPs and appear to be working well. The unit was scheduled to return to service on October 22, 1986.

e. Shutdown to Repair Oil Leak on the West Main Feedwater Pump on October 2, 1986 (Unit 1)

On October 1, 1986, a low lube oil pressure alarm was received on the West MFP. The licensee immediately inspected the pump and noted excessive oil coming out of the West MFP motor enclosure. The licensee, after conducting a preliminary investigation, commenced a shutdown of Unit 1 to perform a detailed inspection of the MFP. The cause of the oil leak was determined to be improper assembly of the inboard bearing of the MFP motor. The Unit returned to operation at 2335 on October 3, 1986.

f. Accumulation of Sea Shells in Main Condenser (Unit 1)

Power was reduced on several occasions for cleaning of sea shells from the saltwater side of the main condenser. Power was reduced to as low as 20% during the period from August 27 to August 31, 1986 and 64% from September 2 to September 4, 1986.

4. Monthly Surveillance Activities

a. Unit 1

The inspector observed the following surveillance:

SO1-V-2.14.1 Quarterly Auxiliary Feedwater Inservice Pump Test (Dedicated Shutdown Pump)

b. Unit 2

The inspector observed portions of the following surveillances:

31 day surveillance for Reactor Plant Protection System (RPPS) Channel B Channel Function Test (CFT) (Procedure SO23-II-1.1.2, TCN 0-10).

31 day CFT for RPPS Channel C (Procedure SO23-II-1.1.2, TCN 0-6).

31 day surveillance on turbine plant area sump radiation monitor (2RT-7821) (Procedures SO23-II-9.17, TCN 4-2, SO-23-XXV-4.42, TCN 0-2).

18 month calibration of control room airborne particulate/iodine monitor Channel A (2/3 RT-7825 A2) (Procedure SO23-II-4.37, TCN 3-9).

31 day surveillance on Control Room Emergency Air Cleanup System Train B (CREACUS) (Procedure SO23-3-3.20, TCN 7-3).

92 day surveillance on plant vent stack/waste gas holdup tank radiation monitor (2/3 RT 7808A, B, C) (Procedure SO23-XXV-4.18, TCN 0-2).

Electrical test portion of the 31 day reactor plant protection system matrix trip path testing (Procedure SO23-II-1.1.5, Rev 0, Att 2).

31 day surveillance (functional test for control room isolation train B) on control room airborne gas monitor (2/3 RT 7825) (Procedure SO23-II-4.9, TCN 8-7).

18 month calibration of 2PT-6462 (at outlet piping of CCW critical loop A heat exchanger) (Procedures SO/23-II-8.10.1, TCN 0-7; SO23-II-9.13, Rev 6, TCN 6-6).

c. Unit 3

The inspector observed the 31 day channel functional test of the excore nuclear instruments, safety channel A. This surveillance is required by Section 4.3.1.1 of the Technical Specifications, and was conducted in accordance with procedure SO23-II-5.5.

The inspector observed the 31 day reactor plant protection system logic matrix functional test. The inspector observed the conduct of this surveillance on several separate occasions, and found that it was well controlled and the procedure was being closely adhered to. This surveillance is required by paragraph 4.3.2.1 of the Technical Specifications, and is conducted in accordance with procedure SO23-II-1.1.5.

All of the above surveillances were observed to be performed in accordance with current plant procedures, and no abnormalities were noted.

No violations or deviations were identified.

5. Monthly Maintenance Activities

a. West Feedwater Pump/Safety Injection Pump Shaft Failure (Unit 1)

The inspector observed part of the repair efforts on the Unit 1 West Feedwater Pump. The pump was inoperable as a result of the pump shaft failure on September 3, 1986. Similar problems occurred in May 1985 and June 1986. The pump shaft fractured at the thread engagement section where the oil pump drive nut is threaded onto the shaft. The licensee's investigation of the failure concluded that the primary failure mode was most likely due to the loss of preload force on the nut, followed by thread to thread fretting between the shaft and the nut. The fretting caused a large free play clearance to be generated for the thrust disk, thereby resulting in a high cyclic force on the nut end face. The licensee revised the maintenance procedure for installing the oil pump drive nut on the shaft to ensure that the proper preload force is applied. The licensee also implemented corrective actions for other identified potential causes of the failures. During discussion of this problem with the inspectors, the licensee agreed that more extensive troubleshooting and root cause evaluation in May 1985 and June 1986 could have identified the pump failure mechanism earlier. The licensee has implemented a more aggressive program for determining root cause.

b. West Feedwater Pump/Safety Injection Pump Motor Bearing Oil Leakage (Unit 1)

The inspector observed part of the repair efforts on the Unit 1 West Feedwater Pump Motor bearings. The pump was taken out of service on October 2, 1986 due to excessive oil leaking from the inboard motor bearing. Upon disassembly of the motor bearing, it was determined that the bearing labyrinth seals had been reassembled improperly. The reassembly error prevented the oil, which normally accumulates in the labyrinth seal from being directed back to the top of the journal bearing. The licensee identified the following weaknesses in the maintenance program which contributed to the reassembly error: (1) an inadequate maintenance procedure which did not properly address labyrinth seal vents and (2) failure to properly identify and control component parts upon disassembly of equipment components. The licensee revised the procedure S01-I-5.68, to clearly identify the requirement to ensure that the vent holes are on the top half of the labyrinth seal. The failure to properly identify and control component parts appears to have been an isolated occurrence, and the inspectors will monitor this item during future maintenance activities.

c. Switchyard Breaker/Disconnects (Unit 1)

The inspector observed maintenance troubleshooting on the open pole alarm on the off-site power supply breaker and disconnects to the Unit 1 C Transformer. The troubleshooting identified no degradation of the disconnects and it was determined that the alarm occurred primarily as a result of the low power placed on the two supply breakers 4032 and 6032.

d. Post Accident Sampling System (PASS) (Unit 2)

The boron meter and the pH analyzer in the Unit 2/3 PASS were noted to be out of calibration during a chemistry surveillance in July, 1986. The inspector observed the licensee recalibrate the PH analyzer (2/3 AI-A503). The calibration was successfully completed in accordance with procedures SO23-II-9.681, Rev 0, TCN 0-1, and SO23-II-9.383, Rev 1. During observation of calibration of boron meter (2/3 AI-A502), the inspector noticed that the I&C technicians performing the above calibration did not appear to be familiar with the procedure (which was recently revised to incorporate steps for using a new sample cart). Section 6.8 of this procedure (Restoration and Return to Service) requires the performance of "a functional test per the design documents." The technicians indicated that they did not understand what this meant and that functional tests should be performed by operations. The I&C technicians indicated that it was the first time they had used this procedure and that no briefing was conducted by the I&C supervisor prior to starting the activity. The inspector reviewed this problem with the I&C supervisor and was informed that a pre-job briefing should have been conducted to discuss the work scope, to go over any new procedures, etc. This problem was also reviewed with the maintenance manager, who committed to reemphasize the importance of proper pre-work briefing with cognizant personnel. With regard to the functional test requirement of the procedure, the I&C supervisor stated that this was a boiler plate statement which had been inserted in the procedure and that a post-maintenance functional test of the PASS is actually intended to be performed by the Chemistry Department. The inspector stressed that technicians should not be left to make a decision as to which steps can be skipped. The licensee later issued a TCN to delete this statement from the procedure.

e. Inlet Drain Valve for Spent Fuel Pool Heat Exchanger E005 (Unit 2)

The inspector examined the valve on September 2nd after a replacement disc assembly had been installed. The inspector also reviewed the maintenance documentation package and discussed the activity with the maintenance and QC personnel. No deviations or violations were identified.

While the maintenance activity was in progress, a maintenance worker outside the spent fuel pool heat exchanger room noticed that a frisker outside the Unit 2 penetration building "jail house" (20 feet away) went off scale and the associated audible alarm sounded. Health Physics was notified and an air sample was taken inside the "jail house" 10 minutes later. In exiting the Health Physics control point, both the inspector and the three maintenance workers discovered contamination on their hands and faces due to noble gases. The collected air sample was analyzed to contain approximately 23 times MPC of noble gases, principally Xe-133. The resultant skin dose to an individual present in that vicinity was estimated to be 0.6 mrad/hr. The Health Physics foreman immediately placed a rope and sign outside the Unit 2 penetration building, declaring it an airborne area. The puff release of noble gases was later determined to be due to leakage through 2HV0511 (pressurizer vapor sample containment isolation valve) during the valve alignment portion of the reactor water inventory balance which is conducted three times a week by operations. A packing leak in 2HV0511 was repaired within two days, prior to the next scheduled surveillance. Air samples were taken in the "jail house" after the valve repair and indicated 0% MPC of I-131 and noble gases. In addition, Health Physics and Operations Departments have reached an agreement on the prioritization of Red Badge Zone Valve and systems leaks.

The inspector considered the above corrective actions taken by the licensee to be adequate.

f. Gas Sampling System

The gas sampling system blower suction pressure relief/safety valve (2/3 PSV 0579) had been observed to leak by, causing the waste gas header flow alarm to annunciate and gas releases out the vent stack.

A maintenance order was generated to adjust the lift setpoint of the valve. The inspector observed portions of the bench test on the valve and reviewed the completed maintenance package. The valve lift setpoint was found to be acceptable. The setpoint as engraved on the valve name plate was 50 psi. However, it had previously been changed to 60 psi per DCP 5023-507 (5/25/84) as indicated in the maintenance order but was never changed on the nameplate. The maintenance technician engraved the new lift setpoint on the nameplate. The entire bench test was observed by a QC inspector.

g. Component Cooling Water (CCW) Heat Exchanger Pressure Switch Repair (Unit 3)

The saltwater differential pressure (d/p) alarm switch, 3 PDSHL-6533, for the CCW heat exchanger, E-002, was continuously in the alarm condition even when the saltwater d/p indication was satisfactory. The licensee removed the switch and found that the tubing had become clogged to the point where the pressure switch could not function. The licensee cleaned the tubing and the pressure pressure switch, and installed the switch back into the system. The inspector observed switch installation and reviewed the work procedure. The inspector observed that the I&C technician was using a screwdriver to tighten a star nut inside the pressure switch, and brought this to the licensee's attention. The licensee inspected the pressure switch to ensure that no damage occurred, and emphasized the proper use of tools to the technicians.

h. Steam Generator Safety Valve Replacement (Unit 3)

During the RCP Seal Outage, the licensee replaced safety valves 3PSV-8407, 8408 and 8409. These three valves were all installed on the same steam header, and were exhibiting excessive vibration during unit operation. The inspector observed the valve replacement and reviewed the work procedure. The evolution was well controlled and conducted in accordance with the procedures. The licensee plans to verify the valve lift setting when the unit enters mode 3.

i. Qualified Safety Parameters Display System (QSPDS) (Unit 3)

QSPDS Channel A has had a problem with the plasma display unit (PDU) since original installation. The PDU will display spurious characters such that the display of safety parameters degrades over time. While this is expected to occur to some extent, the problem has been significantly worse on Channel A for Unit 3 than on any of the other PDUs. The inspector has monitored the licensee's efforts to identify and correct this problem, which has included replacing the PDU, replacing the key pad, grounding the unit at a different location and monitoring radio frequency (RF) noise in the area. The problem was significantly reduced when a shorter connector cable was used, which indicates that the cable has been acting as an antenna and picking up RF noise. The licensee has not determined why the condition is worse for QSPDS Channel A on Unit 3 than it is for Channel B or for either of the channels on Unit 2, but the shorter cable has helped to resolve the problem.

No violations or deviations were identified.

6. Engineered Safety Feature Walkdown

During the inspection period, the inspector walked down major portions of the safety injection system for Unit 2. The system as observed was aligned as required by the unit Technical Specifications and applicable station procedures. One of the rooms which houses HPSI pump 2P-017 and LPSI pump 2P-015 (Room 005) had a health physics lock on the door because of hot spots present at several piping elbows (up to 10 r/hr on contact). A person seeking access to the room would need to obtain a key from Health Physics. The inspector questioned whether an operator's accessibility to the room during emergencies would be affected (delayed) by the lock, and whether use of shielding around the hot spots had been considered. The lock was later removed, since licensee procedures only require Health Physics locks for areas with radiation levels of greater than 15 r/hr. The licensee is currently developing a plan to build permanent shielding around the piping elbows.

No violations or deviations were identified.

7. Independent Inspection

a. Evaluation of Root Cause Assessments Made by the Licensee

The inspectors reviewed several component failures that have recently occurred to assess the licensee's program for determining the root cause of component failures. In particular, the inspectors selected the following examples:

(1) Faulty Potter and Brumfield Relay (Unit 2)

As discussed in paragraph 3b of inspection report 50-361/86-24, the licensee attributed the cause of the Unit 2 reactor trip on July 14, 1986, to the pitted contacts of a Potter and Brumfield relay #KR3DH. However, it is questionable that the minor pitting that existed on the contacts would have caused the relay to fail, and the licensee did not test the relay to confirm the postulated failure mechanism. The troubleshooting and repair effort was conducted under a Shift Superintendent's Accelerated Maintenance (SSAM) work request, which did not provide guidance for conducting the troubleshooting and repair effort. The SSAM did not address root cause identification of the relay failure, and the mechanical relay was not preserved in the "as found" condition so that subsequent testing could be performed. In addition to the procedural inadequacies, the non conformance report (NCR) which addressed the mechanical relay failure was not issued until after the troubleshooting and repair effort was completed. The NCR, in this instance, did not provide for QA overview and in-process control of the failed component.

(2) Spurious Tripping of 2HV-4730 Supply Breaker (Unit 2)

On September 4, 1986, breaker MS-4705, which supplies power to valve 2HV-4730, spuriously tripped open. This valve is a DC powered motor operated valve (MOV) which is located in the auxiliary feedwater (AFW) piping to steam generator E-088. The licensee initiated a maintenance order to replace the breaker, and a replacement breaker was installed on September 11, 1986. The licensee could not identify a cause for the breaker to trip, and after performing the necessary valve surveillance, returned the valve to operable status. On September 27, 1986, breaker MS-4705 spuriously tripped open again. The licensee initiated a maintenance order and did extensive troubleshooting to identify the cause of the problem. This effort included high pot testing of the electrical circuitry associated with the breaker and a search for any electrical noise in the area that might cause the breaker to trip. The licensee has not been able to identify a cause for the spurious breaker tripping, but speculates that it is due to vibration of the electrical panel which houses the breaker. The licensee has instrumented the breaker so that if it trips again, a determination can be made as to the cause of the trip. Although the inspector considers that the actions taken by the licensee for the September 27th occurrence were satisfactory, similar actions should have been taken by the licensee for the September 4th occurrence. Adequate testing was not done to determine root cause, and measures were not taken at that time to enable a root cause determination in the event of subsequent spurious breaker trips.

(3) Failure of Valve 3HV-4706 to Open (Unit 3)

Following the reactor trip that occurred on September 4, 1986, an Emergency Feedwater Actuation Signal (EFAS) was generated due to the low steam generator (S/G) water levels that resulted. Valve 3HV-4706, the steam driven auxiliary feedwater (AFW) pump discharge valve for S/G E-089, failed to open. The licensee issued a maintenance order to investigate the cause of failure. The valve was cycled several times, the limit switch compartment was inspected, the motor windings were meggered, the power feeder cables were meggered and the valve running current was measured. An explanation for the valve failure was not found, and the licensee declared the valve operable at 0140 on September 5, 1986. Unit 3 was returned to service on September 5, 1986. Following the reactor start-up, the licensee revised the original maintenance order to provide instructions to replace the breaker for valve 3HV4706. The maintenance order was not worked until September 9, 1986.

On September 8, the inspectors expressed concern that troubleshooting performed on September 5 had not been adequate to determine the cause of valve malfunction. On September 9, the licensee initiated additional troubleshooting of the breaker for valve 3HV4706 and found that the supply breaker for valve 3HV-4706 was not properly set to give adequate margin between the valve motor full load current and the breaker instantaneous trip current setting. The licensee determined that the breaker was improperly set during original installation, and is currently assessing corrective actions to identify any other breakers that may be set incorrectly.

The inspector expressed concern that the shift superintendent's accelerated maintenance (SSAM) process may have contributed to inadequate root cause assessments. In particular, the inspector noted that many equipment malfunctions which require a careful and disciplined root cause assessment are likely to occur under conditions which warrant use of the SSAM process. The inspector noted that the use of a SSAM may contributed to the problems involving the Potter and Brumfield relay, valve 2HV4730 and valve 3HV4706, as discussed above. The specific aspects of the SSAM process which appear to warrant additional consideration fall into two categories:

(a) The criteria for using a SSAM rather than a normal maintenance order (MO) - The use of a SSAM did not appear to be warranted in the instance of relay troubleshooting, since the plant was already in Mode 3.

(b) The specific guidance provided by the SSAM procedure - Incorporation of additional guidance in the basic SSAM procedure with regard to root cause evaluation and preservation of "as found" conditions may provide greater assurance of proper evaluation and correction of future equipment malfunctions.

The inspectors are concerned that these above examples may indicate that additional licensee attention is needed in the area of root cause assessment. Furthermore, it appears that the Quality Assurance (QA) organization may need to take a more aggressive role in the area of root cause evaluation.

The inspectors will review the licensee's assessment of corrective actions to identify other breakers that may have incorrect trip settings. In addition, the adequacy of the SSAM process to determine component failure root cause and the extent of QA involvement in this process will be further evaluated as open item (50-362/86-25-01).

b. IST on AFW Pump

The inspector observed the In Service Test (IST) of the Unit 2 Steam Driven Auxiliary Feedwater Pump (2P-140) which is performed monthly as required by the Technical Specifications 4.7.1.2.1. All measured parameters were within the acceptable ranges and the pump did not exhibit any abnormal performance trends.

c. CRIS Radiation Monitors

On September 20, 1986, while Train B of the Control Room Isolation Systems (CRIS) radiation monitors (2RT-7825) was under routine surveillance, the CRIS Train A monitor (2RT-7824) had essentially no flow through it. The operator manually initiated CRIS and 2RT-7825 was subsequently returned to service after the surveillance. The fan belt of the blower for 2RT-7824 had broken - possibly due to warm temperature in the room which made the belt brittle and eventually broke. The licensee performs preventive maintenance on these fan belts every 92 days and the next scheduled maintenance was on September 30, 1986.

Technical Specifications (T.S. 3/4.3.2., 3/4.3.3) require that control room emergency air clean up system be initiated and maintained in the isolation mode within one hour when both Trains of CRIS are out of service. Control room annunciators associated with these monitors are: CRIS TR A Hi Radiation/Trouble, and CRIS TR B Hi Radiation/Trouble. The operator, in response, must go to the hallway outside the control room to identify the failed monitor (i.e., gas or iodine/particulate) and return to the control room to determine what actions to take. As indicated in the corresponding alarm response procedure, causes of these two alarms include channel failure, loss of power to CRIS, and high radiation level in the control room complex. "Channel failure" is intended to mean failure in the monitor and/or in any portion of the circuit downstream of it. Low flow or no flow to a monitor, as in the case mentioned above, would not have caused this alarm to flash. Instead, an amber light out in the hallway would have been lighted, according to some operators, the status of these radiation monitors is checked once per shift. If loss of flow to the monitors occurs after the shiftly surveillance, it would be unnoticed unless and until someone goes out to the hallway. By the same token, if the light bulb burns out, a low flow condition would also remain unknown to the operator. The inspector noted that in the event of real emergency, (high radiation level in the control room complex) the "Control room area radiation monitor high radiation" alarm would annunciate. The inspector was informed by the licensee project engineer that a DCP had been generated to provide direct indication in the control room of the status of individual radiation monitors. Implementation of the DCP will be completed in the next few months and will resolve the above concern. The implementation of adequate compensatory measures to ensure proper response to radiation monitor failures, pending completion of the DCP, remains an open item (50-361/86-27-01).

d. Resin Transfer

Spent resin slurries are normally dewatered to §0.5% free standing water prior to packaging, shipping and ultimate disposal. The inspector observed the licensee perform the water separator relative humidity end point determination. No violations or deviations were noted.

e. Replacement Operator Training

Region V was requested by Mr. William R. Russell, Director, Division of Human Factors Technology, NRR, to conduct an inspection to determine if the licensee has been conducting replacement operator training according to the requirements of 10 CFR 55 and NUREG 0737. Emphasis for this, inspection was to be on in plant practical factors, three months on shift training, and retention of records. This inspection was conducted in office with appropriate records supplied by facility personnel.

(1) Completion of Practical Factors

In discussions with plant training personnel, and based on examination of representative records, it was determined that the last class of license candidates that Region V examined had completed the required training as outlined in the facility's replacement training program. The implementation of the INPO accredited program however, had not been completed at the time these individuals had commenced their training. Therefore the facility had these individuals complete their training for INPO accreditation certificates after they had completed the training required under the replacement training program. This meant that some individuals did not complete this aspect of their training program until after they had received their licenses. The review determined that those items that had not been completed were not required for meeting the NRC requirements for licensing (10CFR 55 and NUREG 0737).

(2) Retention of Records

The facility is committed per FSAR Chapter 13.2 to Regulatory Guide 1.8 Rev. 1. "Personnel Selection and Training". This Reg. Guide endorses ANSI 18.1 - 1971 Rev. 1 "Selection and Training of Nuclear Power Plant Personnel". Section 5.6 of the ANSI standard says: "Records of the qualifications, experience, training and retraining of each member of the plant organization should be maintained."

The replacement training program of January 22, 1986, referenced in the Revision 1 to the FSAR Chapter 13.2, does not define specific record retention requirements in this area. In conversations with the facility training personnel they stated that they did retain in permanent plant records a memorandum to file from the Unit Superintendent attesting that the individual had completed all of the required in plant practical factors. The personnel also stated that they did retain all records of in plant practical factors. The personnel also stated that they did retain all records of in plant practical factors training until the individual license candidate is licensed.

(3) On Shift vs. Simulator Training

The facility has not in the past required that their license candidates conduct reactivity manipulations on the plant. The facility does however require that all reactivity manipulations be performed on the plant specific simulator. The license candidates that have gone up for licensing in the past have also performed at least 5 manipulations on the plant. Region V

Operator Licensing personnel have informed the facility that this is a requirement, to establish that the individual license candidate has been trained to operate the actual controls of the plant. The training personnel have indicated that they will have their license candidates perform the 5 manipulations requirement on the plant.

f. Environmental Qualification (EQ) of Auxiliary (AFW) Valves (Units 2/3)

When conducting follow-up inspection associated with AFW containment isolation valve 2HV-4730, the inspector noted that the valve is not included in the licensee's EQ program. This appeared to be inconsistent with the requirements of 10CFR50.49 because this valve, along with the other three AFW containment penetration isolation valves associated with both trains of AFW, is located in a small concrete structure (doghouse) which also houses parts of the steam generator (S/G) blowdown system for both S/Gs. The blowdown system components which are located in the doghouse include the containment penetrations and associated isolation valves, downstream check valves, a welded pipe restraint and associated piping. The AFW valves located in the doghouse are HV-4714, HV-4715, HV-4730 and HV-4731. These valves are for containment isolation purposes and are normally closed, but are required to open upon receipt of an emergency feedwater actuation signal (EFAS). The AFW valves and the blowdown valves located in the doghouse are not included in the licensee's EQ program. This configuration is essentially the same for both Units 2 and 3. The inspector addressed this issue with the licensee, and the following points were discussed:

(1) Pipe Break Scenario - The licensee stated that a break in in the blowdown piping is not postulated as stated in the FSAR, paragraph 3.6A.3.4.2, and allowed by Branch Technical Position MEB 3-1 dated 1975.

(2) Blowdown System Component Failure - The licensee stated that if the blowdown piping did actually break in the doghouse area, the effect on S/G water levels would be minor, a reactor trip would not occur, and a need for auxiliary feedwater would not exist. This scenario would encompass any possible component failure.

(3) Inservice Inspection (ISI) Requirements - The licensee stated that the blowdown piping from the penetrations to the blowdown penetration isolation valves is ASME Section III Class 2 piping; and is inspected as required by ASME Section XI. There is no ISI performed on the ANSI B31.1 piping and welded restraining welds located downstream of the blowdown isolation valves.

The inspector has reviewed the FSAR, and the following aspects of this issue remain in question:

(1) The design requirements for the ANSI B31.1 sections of blowdown piping are not addressed in the FSAR, and paragraph 3.6.2.1.2.2.D states: "Pipe breaks are not postulated in piping between containment isolation valves (up to and including the pipe whip restraints that define the terminal ends for the run)...." Evidently the licensee is using some other criteria such that a pipe break is not postulated at the welded pipe restraint.

(2) The pipe restraints, which are welded to the blowdown piping, are designed such that the welds are accessible for 100% volumetric examination as required by the FSAR, paragraph 3.6.2.1.2.2.D.2.f, but the licensee currently does not perform ISI on these welds.

(3) Paragraph 3.6A.3.5.2.4 addresses EQ regarding the AFW valves inside the AFW pump room. EQ is required for the postulated event of a break in the steam line to the AFW pump turbine. This event does not seem to be any more severe than a break in the blowdown piping inside the doghouse, and it does not appear to be consistent to exclude the AFW valves located inside the doghouse from the EQ requirements.

A break in the blowdown piping or component failure (such as a failed packing gland or failure of a gasketed joint) within the doghouse area has the potential of affecting both trains of AFW, and could compromise the safe shutdown capability of the reactor. This issue, applicable to Units 2 and 3, is unresolved pending disposition by NRR (50-361/86-27-02).

g. Reactor Plant Protection System (RPPS) Degraded Power Supply (Unit 2)

As discussed in paragraph 3.b of inspection report 50-361/86-24, a reactor trip occurred while conducting MSIS matrix testing. During this report period, additional anomalies occurred related to the Unit 2 RPPS. On September 3, 1986, a CIAS was received on one of the four trip paths. Later, the I&C technicians observed that an indicating light associated with one of the EFAS trip paths was exhibiting a fluctuating intensity. The licensee initially traced the problem to two separate solid state relay cards, one for EFAS and one for CIAS. The relay cards were replaced, and the problems appeared to be resolved. However, in examining all of these anomalies together, the licensee identified a power supply that was common to the MSIS, CIAS and EFAS problems that had been experienced. The power supply was tested using a strip chart recorder and an AC ripple was found in the DC output. Evidently, this condition was not severe enough to be detected by a digital voltmeter (DVM) and was not identified during the initial troubleshooting efforts. The licensee now believes that the degrading power supply actually caused the solid state relay cards to malfunction. The degraded power supply was replaced and the other power supplies associated with the RPPS were checked to ensure proper operation. Similar RPPS anomalies have recurred since the power supply was replaced.

h. Loss of Main Steam/Main Feedwater Flow Mismatch Trip Function on July 30, 1986 (Unit 1)

On July 30, 1986, a pressure transmitter (PT-459) in the density compensation circuit of the steam flow instrument failed, resulting in the failure of all three steam/feedwater flow mismatch trips in the reactor protective system (RPS). As a result of the failure of all three channels of a technical specification required RPS function, the licensee initiated a plant shutdown in accordance with the requirements of technical specification 3.0.3.

Prior to completing the plant shutdown, the licensee completed repair of the pressure transmitter, exited the technical specification action statement and returned the plant to power operation.

Prior to exiting the action statement, the inspectors questioned the licensee regarding the basis for continued plant operation with a RPS trip function that is subject to single component failure. At that time, the licensee responded that the steam/feedwater flow mismatch trip was not believed to be taken credit for in the safety analysis and plant protection in the event of loss of feedwater accidents was provided by high pressurizer level trip.

Subsequent to return of the plant to power operation, on October 2, the licensee completed a review which concluded that (1) the trip function of steam/feel flow mismatch trip was taken credit for in the loss of feed/feedwater rupture analysis performed following the TMI accident; and (2) the reactor trip function of high pressurizer level at 70% would have tripped the plant, if the steam/feed flow trip circuit were inoperable, however, the resultant transient was outside the scope of the plant design analysis (e.g. it was determined that the pressurizer would go solid and cause the primary safety valves to lift and pass water instead of steam). As a result, the licensee took prompt action to implement compensatory measures to eliminate dependency on the steam/ feedwater flow mismatch trip and maintain the plant within its existing design analysis (e.g. the licensee reduced the setpoint of the high pressurizer level trip from 70% to 50% pressurizer level).

During subsequent review of this problem with licensee management, the inspector again expressed concern regarding the decision to return the plant to power operation prior to clearly establishing the basis for operation with a RPS function that is subject to single component failure. The licensee stated that the decision to return the plant to power operation was properly based on the repair of the defective instrument and did not require resolution of the question of RPS single failure criterion. The licensee did agree, however, that the basis for continued operation should have been clearly established and documented in a more timely fashion. This issue remains open pending further review (50-206/86-37-01).

8. Review of Licensee Event Reports

86-19 (Unit 2):

This LER was issued to discuss the circumstances surrounding the reactor trip that occurred on July 14, 1986. This event was previously discussed in paragraph 3b of inspection report 50-361/86-24 and is further discussed in paragraph 7 of this report. The LER is misleading. A hypothesis was developed based on the fact that a mechanical relay failed to initially reset. However, the relay did reset when the I & C technicians were trying to gain access to it. In addition, when the relay was bench tested (before the slightly pitted contacts were burnished), there was no indication of degraded relay performance. The facts being as they are, the actual cause of the relay failure is not well understood. A hypothesis for the reactor trip was presented in the LER, but it was stated as factual instead of hypothetical. The inspector has reviewed this LER with the licensee, and the importance of accurate information was emphasized. This point was also stressed at the exit meeting.

Through direct observations, discussions with licensee personnel, or review of the records, the following Licensee Event Reports (LERs) were closed:

Unit 1

86-001	Missed surveillance of diesel generator valves
86-003	Missed plant vent stack filter sample
86-004	Inoperable charging pump
86-006	Missed plant vent stack sample
86-007	Auxiliary feed actuation and steam PT failure
86-008	Reactor trip due to governor valve closure

Unit 2

86-006	Dose Equivalent Iodine Limits Exceeded
86-008	Source Range Neutron Monitor Malfunction
86-009	AFW Pump Steam Supply Check Valve Wear
86-010	FHIS Train ±B± Actuation
86-011	CPIS Spurious Actuation
86-012	PPS Actuation on Low Reactor Coolant Flow
86-014	125 Volt DC Battery Surveillance
86-015	Unit 2 Trip Due to Failure of 1E Inverter
86-017	Pacific Scientific PSA-100 Failures

Unit 3

86-002	Missed CPC Channel Functional Test
86-003	Pressurizer Instrument Nozzle Leak
86-004	Unanalyzed Purge Sample
86-005	Reactor Trip Non 1E Instrument Bus Transient
86-006	Unit 3 Trip During Reactor Startup
86-007	Missed Turbine Building Sump Effluent Sample

86-008 CPIS Actuation
86-009 AFW Pump Steam Supply Check Valve Damage
86-010 Reactor Trip on Loss of Feedwater
86-011 Saltwater Cooling Loops Inoperable

9. Follow-Up of Previously Identified Items

a. Allegation RV-86-A-010

(1) Characterization

The alleger, a contract maintenance worker, reported that workers can be fired for raising personnel safety concerns. The alleger stated that a Unit 1 foreman stated this to the alleger.

(2) Implied Safety Significance to Operation

This item would be of major safety significance, if the allegation is substantiated.

(3) Assessment of Safety Significance

Based upon interviews with twelve contract (Fluor) maintenance personnel, the inspector determined the following:

(a) Eleven personnel stated that weekly safety meetings are held as part of the licensee's emphasis on personnel safety practices.

(b) The average on site experience for the twelve workers was eight years.

(c) Half the workers interviewed rated the Industrial Safety Practices as excellent and half rated them as good. Several workers stated that the San Onofre plant was the most safety oriented facility at which they had ever worked in the last ten to twenty years.

(d) All twelve workers personally knew who the Fluor Personnel Safety Representative was. All twelve felt that they would not be fired for raising industrial safety concerns. Eleven of the twelve workers felt that they would never be asked to work in an unsafe condition because of the safety practices which exist at San Onofre.

(e) One of the twelve workers had raised a safety concern on one occasion. He believed that his concern was satisfactorily resolved and he does not feel that he would be fired over raising safety concerns.

(4) Staff Position

The allegation that workers can be fired for raising safety concerns was not substantiated.

(5) Action Required

Based on the inspector's findings, the allegations were not substantiated. The resident inspectors, as part of observation of maintenance activities on site, will routinely observe safety practices and question workers on the safety practices. This allegation is closed.

10. Exit Meeting

On October 10, 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.