U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-206/89-06, 50-361/89-06, 50-362/89-06

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 Site, San Clemente, California

Inspection conducted: February 19 through April 1, 1989

Inspectors: _____ 6/2/89
F. R. Huey, Senior Resident Inspector — Date Signed
Units 1, 2 and 3

_____ 6/2/89
J. E. Tatum, Resident Inspector — Date Signed

for _____ 6/2/89
A. L. Hon, Resident Inspector — Date Signed

Approved By: _____ 6/2/89
P. H. Johnson, Chief — Date Signed
Reactor Projects Section 3

Inspection Summary

Inspection on February 19 through April 1, 1989 (Report Nos. 50-206/89-06, 50-361/89-06, 50-362/89-06)

Areas Inspected: Routine resident inspection of Units 1, 2 and 3 Operations Program including the following areas: operational safety verification, radiological protection, security, evaluation of plant trips and events, monthly surveillance activities, monthly maintenance activities, refueling activities, independent inspection, licensee events report review, and follow-up of previously identified items. Inspection procedures 30703, 37700, 37828, 61726, 62703, 71707, 71710, 90712, 92700, 92701, 92703, and 93702 were covered.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions and Specific Findings:

1. A number of weaknesses in conduct of plant operation were identified during this report period. The specific weaknesses included inadequate attention to detail (paragraphs 3.a, 5.d and 6.d) and poor implementation of NRC notification requirements (paragraph 4.a).

2. The licensee's program for conducting abnormal plant evolutions was observed to require additional guidance to define those evolutions that may be accomplished without more rigorous procedures (paragraph 5.e).

3. One example of poor engineering work was identified, relative to analysis of Unit 1 feedwater pump miniflow capability (paragraph 8.a).

4. The need for more rigorous development of component surveillance testing requirements was noted (paragraph 8.b).

5. A number of LERs were identified that do not adequately address root cause and corrective action (paragraph 9).

Significant Safety Matters: None

Summary of Violations:

Two violations were identified during this report period. One, applicable to Units 2 and 3, involved licensee failure to report a condition that resulted in a violation of the Technical Specification requirements (paragraph 3.b).

The other violation, applicable to Unit 3, involved licensee failure to adequately control Technical Specification fire doors (paragraph 3.c).

Open Items Summary:

During this report period, 5 new followup items were opened and 16 LERs/followup items were closed; 4 were examined and left open.

DETAILS

1. Persons Contacted

Southern California Edison Company

*C. McCarthy, Vice President and Site Manager
*H. Morgan, Station Manager
D. Herbst, Quality Assurance Manager
D. Stonecipher, Quality Control Manager
*R. Krieger, Operations Manager
*D. Shull, Maintenance Manager
J. Reilly, Technical Manager
C. Chiu, Assistant Technical Manager
P. Knapp, Health Physics Manager
D. Peacor, Emergency Preparedness Manager
P. Eller, Security Manager
*J. Schramm, Operations Superintendent, Unit 1
V. Fisher, Operations Superintendent, Units 2/3
L. Cash, Maintenance Manager, Unit 1
*R. Santosuosso, Maintenance Manager, Units 2/3
*R. Plappert, Compliance Manager
*C. Couser, Compliance Engineer

*Denotes those attending the exit meeting on March 31, 1989.

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. Plant Status

Unit 1

Unit 1 remained shut down in mode 5 during the period, while Cycle X refueling outage work progressed.

Unit 2

The unit operated at full power during this period.

Unit 3

The unit operated at full power during this period.

3. Operational Safety Verification (71707)

The inspectors performed several plant tours and verified the operability of selected emergency systems, reviewed the tagout 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. The inspectors also observed selected activities by licensee radiological protection and security personnel to confirm proper implementation of and conformance with facility policies and procedures in these areas.

a. Plant Material Condition (Unit 3)

On March 3, 1989, while conducting a routine plant tour, the inspector noticed that a 5 gallon bucket was suspended from a small pipe connected to atmospheric dump valve (ADV) 3HV8419. The bucket was placed there by plant operators to divert ADV blowdown line flange leakage away from electrical conduit. In response to a concern raised by the inspector the licensee removed the bucket. As corrective action the licensee developed appropriate guidelines for installation of temporary drip collectors and repaired the leak by replacing the flanges on the ADV.

b. Technical Specification Violation and Failure to Report (Units 2 and 3)

On August 15, 1988, during the Unit 3 Cycle 4 refueling outage, the licensee conducted control element assembly (CEA) drop time testing. A new test method was used such that it measured the total elapsed time from trip signal initiation to opening of the reactor trip breakers (RTBs) and 90% insertion of all CEAs. Previously, the CEA drop time test was conducted by opening individual CEA hold coil breakers and measuring the elapsed time from when the breaker opened to when the CEA was inserted 90%. An assumed time was used for the delay time from trip signal initiation to opening of the RTBs. The new test method revealed that an additional 0.4 second delay existed due to the electromagnetic decay of multiple CEA coils tied together when the RTBs were opened.

This phenomenon was first recognized at Arkansas Nuclear One in May, 1988. To anticipate the impact on SONGS, the licensee proposed a Technical Specification (TS) amendment and received approval on August 10, 1988 to relax the CEA drop time requirement from 3 seconds to 3.2 seconds. The licensee evaluated the August 15, 1988 test results and determined that the new 3.2 second limit was met. However, the licensee did not reevaluate the CEA drop time data from the previous fuel cycles against the original TS limit by taking the additional 0.4 second time delay into account. In addition, this condition was not evaluated and reported relative to Unit 2. Later evaluation revealed that at least one CEA had exceeded the original TS limit. For example, the drop time of Unit 3 CEA 64 was measured to be 2.9 seconds during cycle one.

Applying the additional 0.4 second delay, the total worst case drop time would have been 3.3 seconds. Paragraphs (a)(1) and (a)(2)(B) of 10 CFR 50.73 require the licensee to submit an LER within 30 days of the discovery of "any operation or condition prohibited by the plant's Technical Specifications." The licensee did not recognize that the plant had operated outside the original TS limit and, contrary to this requirement, failed to report this condition within the required 30-day time period. Failure to make the required report within 30 days of discovery of the condition is an apparent violation (50-362/89-06-01).

After discussion with the NRC staff on December 07, 1988, the licensee reevaluated the reportability concern and submitted LER 50-361/88-31 on January 9, 1989. However, as noted in paragraph 9.b of this report, the LER submitted was not complete. The licensee also submitted a letter on January 6, 1989 to explain the failure to report, and to discuss corrective actions.

c. Fire Protection Door Impairment (Unit 3)

On March 29, 1989, the inspector identified three Technical Specification fire doors that were left open at the 8' level in the Safety Equipment Building. No fire impairment compensatory actions had been established for these conditions. The three fire doors were recently (December, 1988) added to the fire barrier seal list and signs were attached to the doors. The licensee's failure to properly control Technical Specification fire doors is an apparent violation (50-362/89-06-02).

4. Evaluation of Plant Trips and Events (93702)

a. Reactor Coolant System Leak (Unit 1)

On March 29, 1989, at approximately 12:30 a.m., the Unit 1 control operator observed that a reactor coolant system (RCS) leak of about 11 gpm developed when the RCS was pressurized to about 135 psig. The reactor was in mode 5, and the RCS was being pressurized to 350 psig in order to perform inservice testing of valves and to run reactor coolant pump (RCP) C for balancing. At the time the leak occurred, the A RCP second stage seal high flow alarm annunciated in the control room, and the operators believed that the leak was coming from the seals on RCP A. The control operator decreased RCS pressure and attempted to stop the leak by cycling the RCP oil lift pump on and off several times, but this had no effect. The control operator slowly increased RCS pressure to 180 psig to see if the seal package would restage to stop the leak. As RCS pressure was increased, however, the leak became worse. At approximately 3:30 a.m., with RCS pressure at 180 psig, the RCS leak was approximately 33 gpm. It appeared that the RCP seals were not going to restage and the control operator reduced RCS pressure to atmospheric and began draining the pressurizer in an attempt to stop the leak. After the RCS was depressurized, the A RCP second stage seal high flow alarm cleared and leakage from the third stage seal

stopped. However, RCS leakage continued at the rate of approximately 20 gpm. The licensee stopped the leak at approximately 6:00 p.m., when residual heat removal (RHR) pump discharge pressure was isolated from the RCP seal water return line.

Licensee Evaluation

In evaluating this condition, the licensee determined that the RCP seal water return line was being pressurized by the RHR pump due to seat leakage past valve LDS-CV-413. The licensee determined that A RCP seal water return isolation valve PCV-1115A was also leaking past its seat, which allowed the second stage seal to be pressurized. The licensee believed that either the seals associated with the A RCP were cocked slightly or the isolation valves associated with the A RCP vapor seal head tank (RCP-HCV-427A or RCP-069) leaked by when the RCS was being pressurized, resulting in the initial 11 gpm RCS leak from the A RCP pump seals. As RCS pressure was increased, RHR pump discharge pressure exceeded the seal return line relief valve (RCP-RV-2004) setpoint of approximately 150 psig and RCS water was relieved to the RCS drain tank. This accounted for the 33 gpm leak rate when the RCS was pressurized to 180 psig. Although action was taken to depressurize the RCS, the leak did not stop because relief valve RCP-RV-2004 had stuck open. The leak was stopped by making adjustments to the valve actuator to increase the closing force on LDS-CV-413, which isolated RHR pump discharge pressure from the seal water return line.

Reportability

When the control operator initially recognized that RCS leakage was approximately 11 gpm, he failed to follow the reporting requirements specified by Operating Division Procedure SO123-0-14, which required NRC notification within one hour of an unisolable leak from the RCS which exceeds 7 gpm. During a subsequent review of procedure SO123-0-14, the Operations Manager concluded that the event was reportable. Based on this determination, the Unit 1 Shift Superintendent notified the NRC of the event at approximately 7:00 a.m. on March 29, 1989, about 7 hours after the leak was identified. This item remains open, pending completion of the licensee's root cause evaluation of why the event was not properly reported (206/89-06-01).

No violations or deviations noted during the inspection.

5. Monthly Surveillance Activities (61726)

During this report period, the inspectors conducted inspection of the following surveillance activities:

a. Observation of Routine Surveillance Activities (Unit 1)

SO1-12.8-17 (TCN 3-2) Sphere Isolation Valve Test

SO1-12.8-2 (TCN 6-9)	Cold Safety Injection System (SIS) and Loss of Offsite Power Test
SO1-12.8-23 (TCN 0-5)	Dedicated Safe Shutdown System Functional Testing
SO1-12.8-13 (TCN 3-5)	Recirculation System Leakage Test
SO123-0-23 (TCN 0-5) Log #1-89-09	Allow Inservice Inspection (ISI) Hydro of Containment Spray Recirculation System
SO123-0-23 (TCN 0-5) Log #1-89-14	Verify Proper Operation of CV-142, CV-143, CV-144, FCV-456, and MOV-1204 Sequencer Signals

b. Observation of Routine Surveillance Activities (Unit 2)

SO23-3-3.25 (TCN 7-35)	Once a Shift Surveillance (Modes 1-4)

c. Observation of Routine Surveillance Activities (Unit 3)

SO23-11-1.1.3 (TCN 2-5)	Surveillance Requirement, Reactor Plant Protection System, Channel C Functional Test
SO23-3-13.34 (TCN 7-4)	Turbine Overspeed Protection Valve Operability Test

d. System Leakage Testing (Unit 1)

During the recirculation system leakage test that was conducted on Unit 1, the inspector observed the following weaknesses:

* Specific responsibilities were not properly assigned to the operators who were monitoring system leakage. It was left to each individual operator to determine which parts of the system he would observe for leakage.

* Communications were not properly established between key participants. This could have led to unnecessary delays in stopping system pressurization in the event that a significant leak or other problem developed.

* Health Physics (HP) support and participation were not completely dedicated to the surveillance activity. This could have led to unnecessary delays in controlling the spread of radioactive contamination in the event that a significant leak developed.

* Prior to system pressurization, the high point vent valves were not cracked open to verify that the system was filled and vented. During the normal 10-minute leak test, any air in the

system could have made it difficult to identify system leakage.

* Concurrent with the operating division surveillance that was being conducted, Station Technical Division was also conducting the ten-year ISI for the recirculation system, which required the system to be pressurized for 4 hours. Instead of conducting the system leak check at the end of the 4 hours (which would have been the conservative approach), the operators conducted the leak check following initial system pressurization.

* The procedure did not address seat leakage past CRS-319 (recirculation heat exchanger high point vent). In this particular case, any seat leakage past CRS-319 would pass through non seismic piping through valve CRS-320 to a drain. For leak detection purposes, CRS-320 should be in the open position to allow seat leakage past CRS-319 to be monitored.

* For purposes of the leak test, primary makeup water was used to pressurize the recirculation system, which could cause dilution of the borated reactor coolant. The test procedure did not include specific requirements for verifying that dilution of the reactor coolant system (RCS) did not occur as a result of the leak test. For example, sampling of the RCS, volume control tank or refueling water storage tank was not specified; and flushing and sampling of the recirculation system was not required. The Unit 1 Superintendent verified that boron dilution did not occur as a result of the hydrostatic testing that was performed.

* System leak tests such as this one are infrequent and can provide an opportunity to gather additional information if the test is well thought out. For example, the pressure boundary isolation valves could be evaluated for seat leakage. This degree of engineering involvement was not factored into the test program.

The Unit Superintendent stated that enhancements to existing procedures and improved formality would be considered in addressing the observed weaknesses. This item is closed (206/89-06-02).

e. <u>Inappropriate Use of Abnormal Alignment Procedure (Unit 1)</u>

Operations Division Procedure S0123-0-23 (Control of System Alignments), provides operations personnel with a mechanism for documenting abnormal system alignments or evolutions that were not previously specified or addressed by existing operating instructions. The review and approval process specified by S0123-0-23 is similar to that required for temporary procedure changes and is not as rigorous as that required for issuance of an original procedure, or for issuance of a revision to an existing procedure. The Unit 1 Technical Specifications allow this less rigorous review and

approval process when making a temporary change to an existing procedure only if the intent of the original procedure has not been changed.

The inspector reviewed Operations Division Procedure SO123-O-23 and observed that clear guidance was not included for determining when it is appropriate to use the O-23 procedure for conducting evolutions. Although the procedure stated that testing evolutions, which could potentially involve unreviewed safety concerns, should not be performed using this method, the procedure stated that hydrostatic testing could be performed in this manner. Using an O-23 procedure for performing system hydrostatic tests and other evolutions which have not been thoroughly addressed by existing procedures did not appear to be within the intent originally established for use of the O-23 procedure, and it appeared that additional guidance was required to specify when evolutions fell within the purview of SO123-O-23.

The inspector noted the following specific examples of inappropriate use of the O-23 procedure:

(1) Ten Year ISI Hydrostatic Testing of the Recirculation System

In parallel with performance of the recirculation system leakage test (discussed in paragraph 5.d), the licensee also conducted the ten year ISI hydrostatic test of the system. The Unit 1 Operations Division prepared the procedure for the hydrostatic test in accordance with Operations Division Procedure SO123-O-23. The inspector expressed concern that use of the O-23 procedure appeared to be inappropriate for performing a hydrostatic test. The Unit 1 Superintendent acknowledged the inspector's concern and stated that future hydrostatic tests would be controlled by special operations division procedures to ensure that appropriate interdisciplinary review and approval are obtained, and also to provide a better historical reference file, since O-23 procedures are for one time use only.

(2) Retest of Auxiliary Feedwater (AFW) SIS/SISLOP Features

During performance of the Cold SIS and Loss of Offsite Power (LOP) Test (SO1-12.8-2, TCN 6-9), operation of feedwater regulating bypass valves CV-142, 143, 144; feedwater regulating valve FCV-456 (for A steam generator); and motor driven auxiliary feedwater pump normal discharge valve MOV 1204 were not adequately demonstrated, and were listed as test exceptions. Attachment 2 to SO1-12.8-2 (titled SISLOP Test) specified that valves MOV-1204, CV-142, CV-143, CV-144, FCV-456, FCV-457 and FCV-458 should all go closed during SISLOP initiation. Verification of this action was not completed during the surveillance test due to an oversight in initial valve alignment verification. In order to resolve the test exception, Operations Division wrote an O-23 procedure to verify that

these valves would respond to the Train #1 sequencer demand during SISLOP initiation. The inspector made the following observations:

* During the initial tailboard that was conducted prior to starting the test, operations and maintenance personnel identified that the procedure was not consistent with MO 89022520 for initiating the Safety Injection System/ Loss of Power (SISLOP) actuation. In this regard, it appeared that the O-23 procedure had not been adequately researched prior to issuance. The O-23 procedure was changed to agree with the maintenance order prior to test initiation.

* After steam generator level signals were simulated to be less than 85%, step 5 of MO 89030523 required verification that the steam generator high level partial trip annunciators had reset. Upon completion of this step in the MO, however, the annunciators did not reset. Operations personnel verified that this was proper due to wide range steam generator level signals that were still present. In this case, it appeared that the maintenance order had not been adequately researched prior to issuance.

* Step 13 of the O-23 procedure stated that when SISLOP is actuated on Train #1, the feedwater regulating valve FCV-456 and feedwater regulating bypass valves CV-142, CV-143 and CV-144 should go closed. These valves went closed during the SIS actuation, however, which was prior to LOP initiation. Operations personnel verified that these valves should also close on an SIS actuation as well as during a SISLOP actuation. This appeared to be another instance wherein the O-23 procedure had not been adequately researched prior to issuance.

The Unit Superintendent and the Operations Manager acknowledged the inspector's concern and stated that procedural enhancements would be established in this area. This is an open item pending completion of licensee action (206/89-06-03).

f. <u>Power Operated Relief Valve Stroke Time (Unit 1)</u>

While conducting dedicated safe shutdown (DSD) system functional testing, power operated relief valve (PORV) CV-546 took approximately 80 seconds to stroke open when operated remotely from the safe shutdown panel. During normal operation, CV-546 strokes in approximately 2 seconds. Investigation into the slow stroking of CV-546 revealed that the slow stroking was a result of a design deficiency associated with its solenoid control valves. In particular, the solenoid valve associated with the DSD system utilizes an orifice, resulting in slower valve response than when using the solenoid valve associated with the control room (which does not

involve air flow through an orifice). The licensee is currently evaluating modification of the solenoid valves to provide fast response from both operating stations. This deficiency is not a safety concern, since no credit was taken for CV-546 or its block valve (CV-530) for any accident analysis related to the DSD control panel. Control from this panel is provided for pressure control during cooldown only and slow function of the valve will not affect this control feature. This item is closed (206/89-06-04).

No violations or deviations were identified in this area during the inspection.

6. Monthly Maintenance Activities (62703)

During this report period, the inspectors observed or conducted inspection of the following maintenance activities:

a. Observation of Routine Maintenance Activities (Unit 1)

CWO 89022124 Add Bypass Line on FE-3077

CWO 89030437 Megger Feeder Breaker for Feed Pump G-3A

b. Observation of Routine Maintenance Activities (Unit 2)

MO88122005000 Containment Spray Pump Discharge Flow Indication Calibration

MO89031097000 Safety Injection Tank (SIT) 2T010 Level Indication Anomaly

c. Observation of Routine Maintenance Activities (Unit 3)

MO89030075000 Adjustment to correct large TAVE/TREF mismatch

MO89031366000 Log power on QSPDS Plasma display reads low

MO88101887001 Atmospheric Dump Valve (ADV) 3HV8419 drain line flange leak

MO87120614000 Standby Battery Charger 3B006 Preventive Maintenance

d. Maintenance Activities on Redundant Safety Systems (Unit 3)

On February 10, 1989, Unit 3 was in mode 3, in a 72-hour action condition due to an AFW pump outage. AFW pump 3MP504 motor was disassembled for inspection of the stator winding. The inspector found that while 3MP504 was inoperable, the adjacent steam driven AFW pump 3P140 was being prepared for painting. Various parts of the pump including the sight glasses and a fire detector were covered with masking tape.

When the inspector brought this observation to the shift superintendent's attention, he immediately evaluated the operability of the pump and found that it was not affected by the masking tape. The licensee also promptly removed the masking tape from the pump.

In response to the inspector's inquiry, the licensee investigated and found that the painter received a blanket maintenance order to paint the AFW pump rooms before the 3MP504 outage started. The control room work authorization was given once at the beginning of the evolution to allow the MO to be worked over a period of several days. Recognizing the weakness in this process, the licensee trained the painters on this incident and instructed them to obtain approval from the control room at the beginning of each shift while work is being completed for all future painting evolutions that impact safety related equipment. The licensee also committed to review the work authorization process for long term improvements to prevent recurrence.

Furthermore, the licensee interviewed the equipment operators who walked down the plant systems as part of the shiftly surveillance. Some of them had observed similar conditions in the AFW pump area and reported these conditions to the control room. However, no action had been taken by the control operator to correct the situation. As a result of this observation, the licensee briefed the operations staff and emphasized the importance of all operators being sensitive to abnormal conditions.

This item remains open, pending completion of licensee corrective action (50-362/89-06-03).

No violations or deviations in this area were noted during the inspection.

7. Engineered Safety Features Walkdown (71710)

Unit 2

The inspector verified the breaker alignment of the AC electrical system while the unit was in mode 1. Procedure SO23-3-3.27.2, titled Weekly Electrical Bus Surveillance, and selected electrical diagrams were used.

No violations or deviations in this area were noted during the inspection.

8. Independent Inspection (37700, 92703)

a. Miniflow Recirculation Requirements for Safety Related Pumps (Unit 1)

On May 5, 1988, NRC Bulletin 88-04 was issued to address a concern regarding miniflow requirements for safety related pumps. The inspector reviewed the licensee's evaluation relative to the Unit 1 main feedwater pumps, which are used to inject borated water into

the reactor coolant system during postulated events. No test data existed for operation of the feedwater pumps in the safety injection mode, and the licensee's conclusions were based on calculations. The inspector reviewed the licensee's calculations and made the following observations:

* A number of assumptions were made that did not appear to be appropriate. For example, all elbows were assumed to be long radius and the validity of this assumption was not established by as-built verification; the design miniflow requirement was assumed to be acceptable without supporting data; and inservice test data for feedwater miniflow through the feedwater pump were assumed to be applicable to safety injection miniflow through the feedwater pump without supporting data.

* As-built design information was not verified by a system walkdown.

* CV-875A and CV-875B (feedwater pump safety injection miniflow isolation valves) were assumed to be either fully open or fully closed for purposes of the calculation. Two weeks after the calculation was completed, NCR1-P-7006 was written which identified that CV-875A stroked only 7/8" instead of the design stroke of 1". The NCR was dispositioned to accept this condition, but the miniflow calculation was not revised to reflect this new information.

Based on this review, the inspector concluded that the licensee's calculations did not demonstrate that feedwater pump safety injection miniflow was adequate. The licensee stated that feedwater pump safety injection miniflow data would be obtained to satisfy the inspector's concern when the unit enters Mode 3. This item is closed (206/89-06-05).

During review of the licensee's calculations relative to feedwater pump miniflow, the inspector observed that the pump head curve for safety injection pump G-50B was not representative of the inservice test (IST) data plotted on the curve. The pump head curve indicated a maximum differential head of about 300 feet, but IST data documented a differential head of 342 feet during miniflow operation. The inspector questioned the accuracy of the pump curves for the safety injection pumps and, in particular, the accuracy of the net positive suction head (NPSH) curve and how it relates to refueling water storage tank (RWST) level requirements for pump operation. The licensee evaluated this concern and determined that the maximum required NPSH was approximately 16 feet, as compared to a minimum available NPSH of approximately 32 feet (for minimum allowable RWST level). The licensee also reviewed the pump curves for all other safety related pumps and confirmed that specified pump curves were correct. The licensee committed to correct the safety injection pump curve in the FSAR. This item is closed (206/89-06-06).

b. Periodic and Post-Modification Testing Program (Unit 1)

During this report period, the licensee notified the NRC of several component design deficiencies, a number of which could have been identified in a more expeditious manner if periodic component surveillance and post modification testing programs had been more rigorously implemented. The inspector noted the following specific design problems in this regard:

* The diesel generator sequencing logic did not contain a seal-in feature for the loss of power signal.

* The control circuit of the south refueling water pump (G27S) contained a jumper wire which could have prevented the automatic start of the pump during a containment spray actuation with loss of off-site power present.

In addition to the above observations, the inspector noted that certain interlock features relative to the operation of the feedwater regulating valves and bypass valves were not required to be periodically tested. Specifically, the following interlock features were not tested:

* MOV-1204 lockout feature following SIS initiation.

* Ability to control valves CV-142 and FCV-456 upon reset of FCV/CV-TRN A SIS interlock.

* Ability to open valves CV-143, CV-144, FCV-457 and FCV-458 upon reset of FCV/CV-TRN B SIS interlock.

The licensee stated that the inspector's concerns regarding post-modification testing would be addressed as a function of the design review program that is currently underway. This item remains open pending licensee action to define program requirements (206/89-06-07).

No violations or deviations were identified in this area during the report period.

9. Review of Licensee Event Reports (LERs) (90712, 92700)

Review of LERs included direct observations, discussion with licensee personnel, or review of related records, as appropriate to determine whether the event had been properly described and whether the root cause and appropriate corrective actions had been identified.

a. Based on this review, the following LERs were closed:

Unit 1

88-17 Potential Non-Conservatism with Technical Specification Requirement for Auxiliary Feedwater Storage Tank Volume due to Calculation Oversight

88-20 Steam Generator Wide Range Level Indication System Contrary to Post-TMI Design Requirements

88-21 Containment Fire Protection Spray Inoperable Due to Plugged Nozzles

89-01 Reactor Vessel Thermal Shield Support Block Bolts Out of Tolerance

89-03 Non-Conservative Failure Mode of Component Cooling Water Valves Due to Inadequate Single Failure Analysis

89-05 Diesel Generator No. 2 Automatic Start Due to Loss of Bus Signal

89-06 Delinquent Fire Watch for Inoperable Fire Detectors Due to Personnel Error

Unit 2

88-10 R1 Inoperability of Both Trains of Emergency Chilled Water Due to Low Freon Levels

This report addressed a problem involving failure to properly define the design basis for Freon level in the emergency chiller units. Although the LER provided a good root cause evaluation associated with the specific problem of an improperly implemented design basis for the emergency chiller system, the LER did not specifically address possible generic concern related to other standby safety system parameters which may not have been properly identified and implemented into appropriate station operating and maintenance procedures. This was discussed in Inspection Report Nos. 50-361/89-35 and 50-362/89-35 and the enforcement conference which was conducted pursuant to that report.

89-01 Auxiliary Feedwater Pump Motor Failure

89-02 Entry Into Technical Specification 3.0.3 During Feedwater Block Valve (FWBV) Post-Maintenance Testing Due to Absence of a T.S. Action Statement

89-04 Reactor Trip During Control Element Assembly Insertion Due to Operator Error

89-05 Spurious Emergency Feedwater Actuation Signal No. 2 During Surveillance Testing

89-06 Control Room Isolation System Train "B" Spurious Actuation During Transfer Operation Due to Procedural Deficiency

b. The following LERs were not closed based on the reviews conducted, for the reasons indicated:

88-18 (Unit 1) Steam Generator Tube Sleeve Leakage Problems

This report addressed a problem involving the operation of Unit 1 with steam generator tube sleeving deficiencies which did not meet the plant design requirements.

The report did not appear to fully address the applicable root cause and corrective actions for this event. In particular:

* The report identified that during a Unit 1 maintenance outage in March 1988, the licensee performed an evaluation of indications of inadequate roll of several steam generator tube sleeves and concluded (incorrectly) that the plant could be safely operated until the next refueling outage with this condition uncorrected. On this basis, the unit was returned to power operation in July 1988. However, the report did not address the reasons for the inadequate technical evaluation that was performed in March 1988, nor the corrective actions warranted to preclude recurrence.

* The report identified that in 1981, several errors appear to have been made involving failure to properly identify indications of inadequate sleeve roll on eddy current test strip chart traces. The report did not address the root cause or corrective actions for this deficiency.

88-31 (Units 2 and 3) Control Element Assemblies (CEAs) Exceed Technical Specification Allowable Drop Times

This report addressed a problem involving control element assemblies (CEAs) which were discovered to exceed allowable technical specification drop times. As discussed in the report, one aspect of this event involved the improper assumption of a "nominal" 200 millisecond processing time in performing the CEA drop time calculations. When this processing time was actually measured, as recommended by the vendor, it was determined to be about 60 milliseconds, resulting in rod drop calculation nonconservatism of about 140 milliseconds.

The report did not address the root cause or corrective actions for this deficiency.

89-01 (Unit 3) Reactor Trip Involving an Improperly Installed Uninteruptible Power Supply Jumper

This report addressed a problem involving a reactor trip which resulted from the failure of a non-1E uninteruptible power supply. The failed power supply resulted in spurious closure of feedwater valves, causing a low steam generator level reactor trip. The report identified that, as a result of the licensee's investigation of this event, a jumper wire was discovered to be improperly installed in a power supply component. The licensee determined that the jumper had been improperly left in the power supply component following a June 1988 maintenance activity.

The report did not address the root cause of why the licensee missed opportunities to identify the improperly installed jumper during previous instances of failure of the subject power supply in July and October 1988.

The LERs discussed above as not having adequately addressed all aspects of the event were identified to licensee management. A request for resubmission of these LERs and for a description of corrective actions to ensure that future LERs are complete was included in the letter transmitting this inspection report.

No violations or deviations were identified.

10. Follow-Up of Previously Identified Items (92701)

a.- (Closed) Unresolved Item (206/88-03-05), Backup Nitrogen System Design for AFW Flow Control Valve Inadequate

- In response to the inspector's concern, the licensee had defined the design criteria applicable to the safety related backup nitrogen system, and had documented these criteria in Revision 2 of Design Criteria Manual M-86363. Based on the design criteria that were established, the licensee completed modifications to the backup nitrogen system during the current refueling outage. This item is closed.

b. (Closed) Followup Item (206/88-17-P), M&K Diesel Generator Failure due to Loss of Generator Voltage

In a letter dated September 28, 1988, Morrison-Knudsen Company notified the NRC of a potentially generic problem applicable to the generator field breaker on EMD Model 999 diesel generator systems. The licensee's evaluation concluded that this problem was not applicable to San Onofre Unit 1 because the emergency shutdown diesel generator system is not an EMD Model 999 system. This item is closed.

c. (Open) Open Item (361/87-20-01), Steam Driven AFW Pump Speed Control Deficiency

The licensee replaced the EG-M and ramp generator modules and monitored the operation of the steam driven AFW pumps at both units.

The pumps have been operating properly during all subsequent surveillance tests. The licensee is still evaluating the root cause of the module failure with the supplier under NCR 2-2067. This item remains open pending review of the final NCR disposition.

d. (Closed) Open Item (362/89-15-01), Evaluate the Adequacy of Flow Instrument Calibration

To address the failure of flow transmitter 3FT-034102, the licensee completed an interim root cause analysis. The licensee found that although the transmitter appeared to respond properly at atmospheric conditions, at elevated pressure the zero set point shifted and gave erroneous indication. Consequently, the licensee revised I&C procedure S0123-II-9.14, titled Electronic Differential Pressure and Pressure Transmitter Calibration, to include a static alignment at expected operating pressure as recommended by Foxboro.

The licensee was also planning to install hydraulic snubbers to minimize premature damage to pressure transmitters caused by pump-induced pulsations. The inspector considered the licensee's corrective actions to be satisfactory. This item is closed.

11. Exit Meeting (30703)

On March 31, 1989 an exit meeting was conducted with the licensee representatives identified in Paragraph 1. The inspectors summarized the inspection scope and findings as described in the Results section of this report.

The licensee acknowledged the inspection findings and noted that appropriate corrective actions would be implemented where warranted. The licensee did not identify as proprietary any of the information provided to or reviewed by the inspectors during this inspection.