U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos.:	50-361/93-38 and 50-362/93-38
Docket Nos.:	50-361 and 50-362
License Nos.:	NPF-10 and NPF-15
Licensee:	Southern California Edison Company Irvine Operations Center 23 Parker Street Irvine, California 92718
Facility Name:	San Onofre Units 2 and 3
Inspection At:	San Onofre, San Clemente, California
Inspection Conducted:	November 18 through December 31, 1993
Inspectors:	J. A. Sloan, Senior Resident Inspector J. J. Russell, Resident Inspector D. L. Solorio, Resident Inspector
Approved By:	H. J. Wong, Chief Reactor Projects Branch II — 1/28/94 Date Signed

Inspection Summary

Inspection on November 18 through December 31, 1993 (Report Nos. 50-361/93-38 and 50-362/93-38)

Areas Inspected: Routine, announced resident inspection of Units 2 and 3 operations program including the following areas: design changes and modifications, operational safety verification, evaluation of plant trips and events, monthly maintenance activities, refueling activities, independent inspection, licensee event report review, corrective action program review, and followup of previously identified items. Inspection procedures 37702, 60710, 62703, 71707, 92700, 92701, and 92720 were covered.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions and Specific Findings:

Strengths

The licensee's evaluation of a failure of Unit 3 reactor coolant pump P003 seal package was thorough and methodical, exhibiting sound judgement, and good management involvement (Paragraph 4).

Operations personnel exhibited, overall, strong communications between operators and command-and-control while operating Unit 3 at reduced inventory conditions (Paragraph 3.a).

Weaknesses

Four recent occurrences involving Operations personnel were identified as illustrating a low level of attention to detail: not setting all alarms in preparation for a reduction in reactor coolant system inventory, failing to assure proper valve lineups before the start of a high pressure safety injection pump, and two examples of poor communications between the control room supervisor and the shift superintendent while trying to resolve a problem with a steam generator low pressure setpoint indication and when containment pressure was building up while the refueling cavity and spent fuel pool were connected (Paragraph 3).

A potential barrier was not discussed in the licensee's Operations Division Event Report related to when a Unit 3 high pressure safety injection pump was operated with no discharge flow path (Paragraph 3.b).

One example of weak design control was identified in the original large break loss-of-coolant-accident analysis (Paragraph 7.a).

The licensee repaired a safety-related valve using Furmanite without controlling that use in accordance with their temporary modification program (Paragraph 7.b).

Significant Safety Matters:

None

Summary of Violations

One violation, with three examples, was identified for failure to follow procedures (Paragraphs 3.a, 3.b, 7.b). One non-cited violation (NCV) was identified for failure to comply with Technical Specifications (Paragraph 3.c). One other NCV was identified for failure to verify the adequacy of design (Paragraph 7.a.2).

Unresolved Items:

One unresolved item was identified regarding conformance of the containment emergency sumps to the originally approved design (Paragraph 7.a.1).

DETAILS

1. Persons Contacted

Southern California Edison Company

H. Ray, Senior Vice President, Power Systems
*R. Krieger, Vice President, Nuclear Generating Station
*R. Rosenblum, Vice President, Nuclear Engineering and Technical Support
*J. Reilly, Manager, Nuclear Engineering & Construction
*B. Katz, Manager, Manager, Nuclear Oversight
*K. Slagle, Manager, Outage Management
R. Waldo, Operations Manager
L. Cash, Maintenance Manager
*D. Breig, Manager, Station Technical
M. Short, Manager, Site Technical Services
M. Wharton, Manager, Nuclear Design Engineering
P. Knapp, Manager, Health Physics
W. Zintl, Manager, Emergency Preparedness
*D. Herbst, Manager, Quality Assurance
C. Chiu, Manager, Quality Engineering
*V. Fisher, Assistant Operations Manager
*T. Vogt, Plant Superintendent, Units 2/3
*G. Gibson, Supervisor, Onsite Nuclear Licensing
J. Reeder, Manager, Nuclear Training
H. Newton, Manager, Site Support Services
*W. Marsh, Manager, Nuclear Regulatory Affairs
*J. Fee, Health Physics Assistant Manager
*J. Hirsch, Manager, Power Generation
*T. Yackle, Manager, Design Engineering, NUC/MECH
*R. Kaplan, Licensing Engineer, Onsite Nuclear Licensing
*R. Giroux, Licensing Engineer, Onsite Nuclear Licensing
*R. Douglas, Licensing Engineer, Onsite Nuclear Licensing
*A. Eckhart, Nuclear Fuels Management
*R. Clark, Supervising Engineer
*G. Johnson, Supervision, ECCS Systems
*M. Lisitza, Shift Superintendent
*R. Brown, Shift Superintendent

San Diego Gas and Electric Company

*R. Erickson, Site Representative

City of Riverside

*C. Harris, Site Representative

*Denotes those attending the exit meeting on January 6, 1994.

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 2

The Unit began the inspection period at 98% power, and operated at 98% power until November 23, 1993. Power was reduced to 80% to support a heat treatment of the circulating water system on November 23, 1993. The Unit returned to 98% power on November 25, 1993 and operated at this power through the end of the inspection period.

Unit 3

The Unit began the inspection period in Mode 6 with core reload from the Unit 3 spent fuel pool in progress for the Cycle VII refueling outage. The core reload was completed and Mode 3 was entered on December 6, 1993. On December 7, 1993, the operators noted excessive leakage from the seal package of reactor coolant pump (RCP) 3P002 and the Unit returned to Mode 5 on December 9 to allow repairs. The seal package was replaced and the Unit entered Mode 3 on December 13. On December 13, during control rod testing, operators observed 5-inch flames coming from the seal package of RCP 3P002. The RCP was stopped and the reactor automatically tripped due to low reactor coolant flow and all safety systems functioned normally. The Unit entered Mode 5 on December 14 to repair the seal package. Repairs, including realigning the RCP lower radial motor bearings, were made and the Unit was synchronized to the grid on December 30. The Unit ended the inspection period at 33% power with power ascension in progress.

3. Operational Safety Verification (71707)

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. 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.

Operations Occurrences

The inspector noted four recent occurrences involving operations personnel. These occurrences are described in detail in the following paragraphs. The inspector concluded that the first example indicated an inadequate level of attention-to-detail on the part of the control room supervisor, the second example indicated poor skill of the craft (a failure to question a valve's position) on the part of the control room supervisor, and the last two examples indicated poor communications between the control room supervisor and the shift superintendent. The inspector noted that all these examples involved senior licensed operators and that the last three involved instances where erroneous operations were second-checked and concurred to by a licensed operator. The inspector also noted that there was time available to the operators in each instance to communicate to shift management, as well as to review procedures.

a. Reactor Coolant System (RCS) Midloop Alarms

On December 9, 1993, during the Cycle VII refueling outage, Unit 3 operators initiated an RCS draindown to a reduced inventory condition (approximately 36 inches above the bottom of the RCS hot leg). The purpose of the evolution was to install dams on the RCS loops associated with reactor coolant pump (RCP) P002 to repair what was believed to be a leaking RCP seal assembly. The seal assembly had been previously replaced during the Cycle VII outage.

The inspector observed the draindown, conducted in accordance with procedure SO23-3-1.8, TCN 7-16, "Draining the Reactor Coolant System," and considered that, overall, the operators performed the draindown in a controlled and deliberate manner. The inspector noted that repeat-backs were consistently used (previously noted as an area for improvement). The inspector viewed as a stength the operators' overall command-and-control and cognizance of important plant parameters.

However, the inspector noted two occurrences which indicated the need for additional Operations management attention, one of which also demonstrated poor attention to detail on the part of the involved control room supervisor.

The first involved Attachment 2, "Draining RCS To The Midloop Condition," to procedure SO23-3-1.8. Operators had not adjusted the setpoint of an alarm required by the procedure before commencing the draindown. Specifically, Step 1.33.3 required the adjustment of the alarm "CET/HJTC Temperature High - 5 degrees above the present RCS temperature (Disabled if OOS)." Operators failed to set two of the four inputs to this alarm. The alarm had two inputs from core exit thermocouples (CETs) and two from heated junction thermocouples (HJTCs). The inputs from the CETs were not set. The Plant Superintendent discovered the omission during review of procedure SO23-3-1.8 approximately one hour after commencing the draindown. After the Plant Superintendent discovered the error, the alarm was set as required. The inspector noted that procedure SO123-0-20, "Use of Procedures," Step 5.1.1, required in part that "the person implementing a procedure has the responsibility and accountability for the correct usage of the procedure. This includes assuring applicable prerequisites are met, precautions are reviewed, and determining that the procedure is adequate to accomplish the desired task." The inspector concluded that the failure of operators to completely set the alarm setpoints before commencing the draindown, as required by procedure SO23-3-1.8, is the first of three examples of a violation of NRC requirements (Violation 50-362/93-38-01).

The superintendent later informed the inspector that the cognizant control room supervisor had been distracted while setting the alarm setpoints, and when he returned to setting the setpoints, he had skipped the two inputs. The inspector considered that this evidenced less than adequate attention to detail on the part of the control room supervisor.

The second occurrence involved the control of RCS inventory which was being drained from the RCS to the radwaste primary tanks (RPT). Attachment 18, "RCS Draindown Calculation Record," to procedure SO23-3-1.8, was used to control the RCS inventory drained to the RPT. Operators used this attachment to determine, based on RPT level increase, the inventory (in gallons) drained from the RCS. Before initiating the draindown, operators determined that approximately 40,000 gallons of RCS inventory needed to be drained to reach the desired level of 36 inches in the RCS hot leg. This was used as an additional check of RCS inventory. After draining the 40,000 gallons from the RCS, the level in the RCS hot leg was approximately 39 inches above the bottom of hot leg piping, not 36 inches as expected. The licensee later determined that the tracking log had an entry indicating that approximately 2000 gallons had been drainded to the RPT, when in fact it had not. Operators then drained an additional 2000 gallons to reach 36 inches. Preliminary discussions with Operations management indicated that improvement of the tracking log was necessary. The licensee later informed the inspector that TCN 7-17 had been incorporated into procedure SO23-3-1.8 to improve the tracking log for human factors purposes. The inspector considered this action adequate.

b. Isolation of HPSI Pump P018 Discharge Flowpath

The inspector noted that the licensee operated high pressure safety injection (HPSI) pump P018 on November 3, 1993, for 45 minutes, in preparation for using the pump to fill the Unit 3 refueling cavity. The pump was run with all isolation valves in the discharge flow path shut. The pump sustained internal damage as documented in nonconformance report (NCR) 93110011. The damage resulted from excessive temperatures and invplved the rotating bundle (the multistage pump impeller), the pump and motor bearings, and the pump seal. The licensee later repaired and/or replaced the affected components and restored operability of the pump.

The inspector reviewed the NCR mentioned above, the Operations Division Event Report (ODER) generated as a result of this occurrence (ODER 3-93-31), and applicable procedures and work authorization records (WARs), and interviewed licensee personnel. The inspector concluded that the ODER adequately addressed the root causes of this occurrence, although one potential barrier that may have prevented this pump damage was not addressed. This is described below.

The inspector noted the following sequence of events: On November 2, 1993, with the reactor vessel defueled, maintenance work was completed under WAR 3-R7PP111 on one of the emergency core cooling system (ECCS) common miniflow block valves to the refueling water storage tank (RWST), valve 3HV9306. An operator was aligning the boundary components and removing the red tags per the WAR return to service (RTS). The WAR RTS directed that another common ECCS miniflow block valve, 3HV9347, be open. The licensee operator conducting the RTS noted that the breaker that supplied power to valve 3HV9347 was open and had a caution tag on it for a hydrostatic test under another WAR (3-R7HYD14). The operator also noted that valve 3HV9347 was closed but not tagged. The control room coordinator, a licensed operator assigned to coordinate the Maintenance and Operations interface, then approved the use of alternate control for valve 3HV9347. The use of alternate control was permitted by procedures SO123-0-20, "Use of Procedures," and SO123-XX-5, "Work Authorizations," but Step 6.8.1 of TCN 0-10 of procedure SO123-0-20 directed that alternate control be used when a step cannot be performed when the associated equipment is being controlled by another plant document.

The inspector noted that even though the caution tag implied that the hydrostatic WAR was in effect, the WAR was not controlling the position of valve 3HV9347 on November 2, 1993, because the WAR had not been reviewed or issued until November 5, 1993. The hydrostatic test caution tag on the breaker had been placed as the WAR was in process of being installed. The inspector concluded that the inappropriate use of alternate control for the position of valve 3HV9347 (to a WAR that was not issued and with the valve actually closed) is the second of three examples of a violation of NRC requirements for failing to follow procedures, in this case procedure SO123-0-20 (Violation 50-362/93-38-01).

On November 3, 1993, the Unit 3 operators aligned HPSI pump 018 (the swing HPSI pump) to train "B" of ECCS, using procedure SO23-3-2.7, "Safety Injection System Operation," in preparation for using HPSI 018 to fill the refueling cavity. The operators used Attachment 9 of this procedure, which directed the alignment and also directed a one-hour pump run using the miniflow return line to the RWST. The Unit operating crew noted that valve position indication lights for valve 3HV9347 were not illuminated, but that the keyswitch was aligned to the open position in the control room. The crew incorrectly concluded that the valve was open and subsequently started HPSI 018. Forty-five minutes later, an operator noted steam coming from the pump room. The crew stopped the pump and later determined that the thermal relief valve on the pump suction had lifted. The inspector concluded that the lack of a questioning attitude on the part of the operating crew when faced with inadequate position information on valve 3HV9347, and the lack of any verification of valve position when confronted with inadequate control room indications, was indicative of poor operating skills on the part of the involved control room supervisor (CRS).

The inspector concluded that the ODER generally addressed the causes and prescribed appropriate corrective actions for this occurrence, except that the ODER concluded that Attachment 9 to procedure SO23-3-2.7 was intended to align only those valves specific to HPSI 018 and not valves common to both trains, such as valve 3HV9347. The inspector noted that Step 1.4 of this attachment directed that other attachments be verified as completed. These attachments were valve lineups that included valve 3HV9347 as well as all valves necessary to establishing a complete suction and discharge flowpath. The inspector concluded that had these lineups been checked, as the procedure appeared to intend, all uncertainty about valve position would have been removed. The involved CRS merely verified that a valve alignment, done in the past, was on file when he performed this step. As the Unit was in the middle of a refueling outage with various WARs being performed and valve positions being changed, the inspector concluded that verifying an obsolete valve lineup in this instance was of little value to determining actual valve position.

c. <u>Steam Generator Low Pressure Setpoint Reduction</u>

On November 30, 1993, the licensee informed the inspector that the Unit 2 control room operating shift (the CRS and the control operator) at approximately 11:00 am had pressed the channel "B" Low Steam Generator Pressure Setpoint Reset pushbutton. The operators were attempting to lower the channel "B" setpoint for steam generator E089 setpoint, which appeared to be indicating about 30 psi higher than the other channels on the control room indicators (lumigraphs). The function of the pushbutton is to lower the low steam generator pressure reactor trip setpoint and the main steam isolation signal setpoint to approximately 163.5 psi below the operating steam generator pressure and also provides input into the automatic feedwater isolation logic.

The operators noted that after pressing the pushbutton the setpoint remained high, but failed to note that the channel "B" setpoint for steam generator E088 had lowered to below the value prescribed in Technical Specifications (TS). This use of the reset pushbutton is not described in procedures nor was this technique discussed with the shift superintendent. At 8:48 p.m. on November 30, 1993, the oncoming operations crew noted the setpoint was low and declared the channel inoperable.

On December 1, 1993, the inspector interviewed licensee personnel, verified the readings of the control room lumigraphs, and reviewed licensee procedures. The inspector noted that no alarms or annunciators were provided to the operators when the TS value for steam generator low pressure setpoints decreased to below TS minimum values.

The inspector concluded the reduction of the setpoint was a violation of TS 2.2.1, "Reactor Trip Setpoints," and TS 3.3.2, "ESF Actuation System Instrumentation." The minimum value allowed by TS was 729 psig, and the licensee determined that the actual setpoint had been lowered to 719 psig. The TS directed that the inoperable channel be placed in trip or bypass within one hour, but the crew took approximately nine hours and 48 minutes to do this. However, there was little safety significance to this incident. Each steam generator has four channels measuring pressure and four independent trip setpoints against which the measured pressure is compared. The one channel being lowered effectively placed the plant protection system (PPS) in a two out of three logic, which it would have been in if the channel was bypassed, rather than two out of four logic.

The licensee retrained and retested the crew involved and provided training to all operating crews on the occurrence. The licensee identified the occurrence and promptly reported it to the inspector. The licensee subsequently issued Unit 2 Licensee Event Report (LER) 93-011, dated December 12, 1993, which the inspector reviewed and found adequate. The inspector concluded that the violation should not be cited because the criteria of Section VII.B of the Enforcement Policy were met (NCV 50-361/93-38-02).

The inspector also concluded that the unit operating crew depressed the pushbutton without procedural guidance and without prior consultations with shift management. The inspector considered this an example of poor communications between the unit operating crews and shift management.

d. <u>Inadvertent Spent Fuel Pool Level Increase</u>

This occurrence is documented in NRC Inspection Report 50-361/93-31 as Unresolved Item 50-361/93-31-06. It is listed here because it is a recent occurrence that also illustrates poor communications between the unit operating crew and shift management. In summary, while in a refueling outage, due to expectations that certain equipment undergoing maintenance would be returned to service within a short period of time, the operating crew allowed pressure to rise in Unit 3 containment. The refueling canal was flooded with the refueling transfer gate open connecting the spent fuel pool. Consequently, the pressure rise in the containment building caused a rise in spent fuel pool (SFP) level such that the SFP overflowed to the building sumps. The inspector concluded that the unit operating crew did not bring the developing plant conditions to the attention of shift management early enough to allow alternate actions to prevent the overflow of the spent fuel pool, and that this contributed to the occurrence. The inspector concluded that this was another example of poor communications between a control room supervisor and a shift superintendent.

The inspector concluded that the four examples listed above, all involving licensed senior operators, illustrated a less than adequate attention to detail, poor operator skills, and poor communications between the control room supervisor and the shift superintendent. The inspector will monitor this area in operations during future inspection activities.

Two examples of a violation and one non-cited violation of NRC requirements were identified.

4. <u>Evaluation of Plant Trips and Events</u> (93702)

<u>Reactor Coolant Pump (RCP) Seal Problems and Reactor Trip - Unit 3</u>

On December 13, 1993, Unit 3 was in Mode 3 with control rod testing in progress, when personnel inside containment observed 5-inch flames near the seal package of reactor coolant pump (RCP) P002. The RCP had been running for approximately 24 minutes at the time the flames were observed. The RCP was secured, thus stopping the flames and generating a reactor trip signal associated with low reactor coolant flow. The licensee determined that the reactor trip was uncomplicated and that control rods had been approximately 1" off the bottom before to the trip. All safety systems functioned properly.

Personnel had been stationed in containment to observe the pump start following replacement of the seal package. The RCP P002 seal package had been replaced twice during the refueling outage. The first seal replacement was a scheduled maintenance activity. The second replacement was due to excessive leakage from the fourth (vapor) seal in the new seal. The licensee's root cause assessment of the problem with the second seal was incomplete at the time of the December 13, 1993 event.

The Unit was cooled down to Mode 5 for RCP repairs, and the licensee developed an extensive work plan to obtain measurements of pump components. The licensee also reviewed measured pump operating parameters before the event and studied wear indications on pump components. An inspection of the pump and motor revealed that the lower radial motor bearing was mispositioned, one of the lock-nuts for a lower radial motor bearing segment was not tight, and the pump thrust ring cover had been eccentric (corrected after the second seal replacement). The licensee experienced difficulties in aligning the lower radial motor bearing and found loose bolts coupling the bearing frame to the motor frame. The licensee determined that these conditions allowed a wobble to develop in the motor and pump shaft. Over time the loose bearing segment backed off so that the shaft had increasing freedom of motion at the lower radial bearing, ultimately resulting in rubbing between the shaft and the thrust ring cover, generating heat in one part of the pump shaft which distorted the shaft and increased the rubbing until sparks and flames developed. The licensee also determined that maintenance had not been performed on the lower radial bearing in the last ten years.

The licensee determined that the pump shaft was straight and performed a successful non-destructive test of the pump shaft. The pump vendor concurred with continued use of the shaft. The lower radial motor bearing was repositioned and the motor was run uncoupled from the pump. The pump was subsequently returned to service. The licensee inspected the other Unit 3 RCPs and found loose bolts which coupled the bearing frame to the motor frame in RCP P003. In addition, two bolts were found missing in RCP P003. The licensee committed to evaluate the significance of potential loose bolts in Unit 2 RCPs by January 31, 1994, noting that instrumentation indicated that RCP vibration in Unit 2 RCPs was acceptable.

The licensee discussed these conclusions in a conference call with Region V personnel on December 22, 1993. The motor was realigned with respect to the pump, and the shaft was re-centered. RCP P002 was subsequently successfully run. The alignment was also checked on RCPs P003 and P004, and the licensee determined that RCP P001 had been correctly aligned during the refueling outage.

Based on the conference call and other discussions with the licensee, the inspector concluded that the licensee's approach to evaluating the root cause after the December 13, 1993, failure was thorough and methodical, exhibiting sound judgment and good management involvement.

No violations or deviations were identified.

5. 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 2)

93112021000, "Exercise All Wires/Studs On All 14 Roto-switches."

b. Observation of Routine Maintenance Activities (Unit 3)

93111823000, "Overhaul High Pressure Safety Injection Pump 3P019. Pump Was Run With Low Flow And Low Pressure."

93120348000, "Filter Plugged Causing Charging Pump MP627 To Cavitate When It Is Running. Clean Filter."

93112003000, "Replace Roto-switch RTS2."

93112006000, "Need To Exercise Each Wire/Stud On Each Of The Remaining 13 Roto-switches On 3G002 On 3A04."

No violations or deviations were identified.

6. Plant Modification and Refueling Activities (60710 and 92720)

Unit 3 Refueling Activities

The inspector observed that the licensee found what appeared to be various foreign objects in the Unit 3 steam generators (SGs) during eddy current testing, that the licensee found Unit 3 feedwater inlet nozzle piping to both steam generators had interior inclusions and cracks, and that one of the bolts that held a roto-test switch in place for the Unit 3 Emergency Diesel Generator 3G003 failed during a routine surveillance test; all during the Unit 3 Cycle VII refueling outage. These occurrences are described below.

a. Unit 3 Steam Generator Feed Water Line Inclusions And Cracks (60710)

On November 19, 1993, the licensee observed two circumferential flaws in the inner diameter of the feedwater nozzle for Unit 3 SG E088 while performing ultrasonic examinations for inservice inspections of the piping. The licensee evaluated the flaws and noted that they were a maximum depth of 0.15 inches and were located near a carbon steel-to-carbon steel weld in the feedwater nozzle. The licensee then performed magnetic particle testing of the interior of the nozzle and found two bands of flaws approximately three and one-half inches wide, each with over 400 inclusions. The licensee ground out the inclusions with the feedwater nozzle still exceeding minimum wall thickness. On November 22, 1993, during preparations for re-welding the pipe that had been removed to provide access to the feedwater nozzle, the licensee noted a 360 degree indication on the piping elbow while performing ultrasonic examinations. The licensee noted that the indication had a maximum depth of 0.025 inches. The licensee ground out the indications and weld repaired the area. The licensee then expanded their inspections of the feedwater lines to include the nozzles, safe end, and elbow welds for both Unit 3 SGs. The licensee found minor indications on the safe end of steam generator E089 (0.002 inches) and indications on the piping elbow (0.024 inches). The licensee removed these indications.

The licensee, using electron microscopy of metal specimens taken from the affected areas, determined that the indications were caused by thermal fatigue aggravated by sulfide inclusions.

The inspector reviewed the licensee actions as they repaired the affected areas. The inspector performed visual inspections of the E088 interior feed inlet piping, and several telephone discussions were held with the licensee, the resident inspector, and staff from Region V and the Office of NRR. In each case, the inspector verified that minimum wall thickness was maintained and that the licensee's root cause determinations appeared reasonable.

b. Unit 3 Diesel Generator Roto-switch Bolt Failure (92720)

On November 28, 1993, the licensee performed a routine surveillance test on Emergency Diesel Generator (DG) 3G003 and the DG output breaker automatically opened while the DG was attempting to increase load. The DG trip was caused by a protective current-differential relay. The licensee attributed the actuation of the relay to a failure of a roto-test switch used to isolate the differential current relay from the diesel protective circuit during testing. The licensee found that one of the bolt heads that anchored the switch in place and provided electrical switch connections had sheared off. The inspector noted that there were 14 roto test switches per DG (with two DGs per unit).

The licensee subsequently inspected the bolts for the test switches on both Unit 2 and 3 DGs, and determined that all but one of the other bolts met minimum strength requirements. The additional bolt failure was determined by the licensee to affect only a non-safety-related test function, and the inspector agreed with this assessment. The licensee examined additional bolts from the failed roto-test switch, along with the failed bolt, and determined that there may have been a manufacturing defect in the failed bolt.

The inspector observed maintenance activities inspecting the remaining bolts and replacing the failed roto-test switch and had no comments. The inspector verified that the remaining switches for both Unit 2 and 3 DGs appeared to be firmly anchored with proper strength characteristics displayed by the anchoring bolts. The licensee informed the inspector that the vendor for the roto-test switches, Meter Devices Company, was evaluating issuing a report (as required by 10 CFR Part 21) concerning possible manufacturing defects in the bolts. The inspector will monitor the vendor's and the licensee's activity in this area during the course of future inspection activities.

c. Unit 3 Steam Generator Foreign Objects (60710)

During the San Onofre Unit 3 Cycle VII refueling outage the licensee detected foreign objects in both SGs as a result of eddy current tests. (An analysis of the licensee's eddy current methodology and results was provided in NRC Inspection Report 50-361/93-31). The inspector noted that several of these objects had interacted with the SG tubing, resulting in detectable tube wear, one of which was through wall. The licensee identified a total of seven loose parts located in the outer rows of the secondary side of Unit 3 SGs. The licensee considered that the loose parts originated from erosion of SG feedrings and distribution boxes during the 1990 time frame. The licensee plugged and staked tubes in the area of five of these loose parts and considered that the remaining two parts had not caused wear to date, and that plugging of the affected tubes was not warranted.

The inspector participated in several telephone discussions with the licensee, and NRC staff from Region V and the Office of NRR. The inspector also reviewed the licensee's safety evaluation for leaving these foreign objects in the SGs, "Evaluation of Foreign Objects in the SONGS Unit 3 Steam Generators," dated December 1993. The inspector noted that the licensee agreed to evaluate shutting down Unit 3 if SG tube leakage reached 100 gallons per day as opposed to the Technical Specification limit of 720 gallons per day. Based on the review of the safety evaluation and the licensee's response to questions during the telephonic discussions, the inspector considered that the licensees actions were adequate.

No violations or deviations were identified.

7. Independent Inspection (92700 and 37702)

   a. Inadequate Design Control (92700)

      The inspector noted one example of weak design control and an unresolved item. These examples apparently occurred during the construction phase of Units 2 and 3.

      1. Units 2 and 3 Containment Emergency Sumps

         The inspector noted containment emergency sumps were apparently not constructed to the design basis as described in the Updated Final Safety Analysis Report (UFSAR) and an applicable Regulatory Guide (RG).

         Background

         On November 22, 1993, the licensee inspected the Unit 3 containment emergency sump as a result of information received via the Institute of Nuclear Power Operations (INPO) Nuclear Network based on deficiencies identified in the emergency sumps at Arkansas Nuclear One Unit 2. San Onfore Unit 3 was in its Cycle VII refueling outage at the time. In San Onofre Unit 3, the licensee discovered an irregular (6-inch maximum) annular thermal expansion gap surrounding a reactor coolant system low temperature overpressure (LTOP) relief line going through the horizontal (top) steel cover plate of the sump compartment. The licensee also found gaps between the top cover plate and penetrations for a vent pipe and a sump isolation valve operator shaft, finger holes in the top cover plates (on a manway section), and gaps between the top panels. The licensee had declared the Unit 2 train "A" emergency sump inoperable on November 22, 1993, based on an inspection of the Unit 2 sump (the Unit was in Mode 1).

         The emergency sumps for both Units consist of one sump divided into separate train "A" and train "B" compartments. The LTOP relief line only penetrated into the train "A" compartment.

The sumps had a quarter-inch steel cover plate with each train cover plate segmented into four pieces. The horizontal cover plate was on top of the vertical screens approximately three feet above the containment floor with a four inch high concrete curb. The sumps in Units 2 and 3 are outside the secondary shield, and water communication is provided by numerous large hallways, corridors, and doorways.

The inspector conducted visual inspections of the interior and exterior of the Unit 3 emergency sump. The inspector determined that the following conditions existed at Unit 3, and probably at Unit 2, at the time of the licensee inspection:

Location	Train	Maximum Clearance (gap)
Vent Pipe	A and B	1/4 inch
Sump Isol Valve Operator	A and B	3/4 inch
Finger hole	A and B	1 inch
LTOP Pipe	A	5 inch
Panel Separat.	B	1/4 inch

The inspector found no abnormalities with the Unit 3 sump screens. The inspector also noted the UFSAR described one drain from the refueling cavity to the emergency sump, which the inspector found with a screen and apparently operable. The inspector found the interior of both trains of the emergency sumps of Unit 3 free of debris.

On November 24, 1993, the licensee repaired the Unit 2 sump and on December 4, 1993, repaired the Unit 3 sump. The licensee installed 1/8 inch thick steel plates to cover the gaps around the involved piping and over the finger holes and excessive gaps between plates. The plates were not affixed to the sump cover plate when they were used around pipes, providing for thermal expansion and contraction of the piping involved. The licensee also shimmed the top cover plates to alleviate smaller gaps between the segments of the top cover plates. Based on visual inspection, the inspector concluded that the Unit 3 emergency sump gaps or clearances had been effectively closed after the repairs were made.

Conclusions

The inspector reviewed construction drawings 23148 (issued April 20, 1979) and 23149 (issued April 10, 1979), and all revisions to these drawings (up to Revision 9 of 23148 issued on January 27, 1983, and Revision 7 of 23149 issued on

October 7, 1982). The inspector also reviewed the UFSAR, Questions and Responses to the UFSAR, and licensee generated NCRs 93110117 and 93110116. The inspector also reviewed associated drawings, design change packages, and Technical Specifications. The inspector concluded that:

- The Unit 2 and 3 sumps were built to the construction drawings with the exception of the panel separation. The only design change made to the sumps was in early 1983, increasing the clearance gaps of the LTOP pipe. This change was made as a result of precore hot functional testing. No 10 CFR 50.59 evaluation was performed before this design change (DCP 3-4 P/S). The original drawings had all the clearances with the exception of the panel separation observed during this inspection period. The drawings did have two minor technical problems; 1) the drawings showed solid panels, the as-built condition is two segments per panel, and 2) the drawings labeled the motor operated valve operator opening as the level transmitter opening.

- The description of the top cover plate as seen in the UFSAR did not appear to have been translated into the design drawings that the plant was constructed to. The UFSAR (Section 6.2.2.1.2.5) describes the top of the sump as "A solid top deck is provided to cover the emergency sump. Covered manways are provided for periodic inspection of the sump interior structure." The illustration of a typical sump in the UFSAR shows a sealed plate with penetrations through the top cover plate for a level transmitter, vent, and isolation valve operator coming, but having no clearances shown (illustrations are a side view, Figures 6.2-52). The UFSAR also gives a comparison of the sumps to RG 1.82 (Table 3A-2). The RG specifies the top of the sump structure to be a solid deck if a screen is not used. The RG also states that the sump should be designed to be fully submersible. The UFSAR states the Unit's sump is consistent with this. However, the inspector also noted that the UFSAR had no detailed drawings or statements regarding openings or gaps. The inspector is further reviewing with NRR the design expectations for the containment emergency sumps during the Unit construction time frame at the end of the inspection period. This item is unresolved pending a determination of these design expectations (URI 50-361/93-38-03).

- The UFSAR describes the innermost screen as having a mesh size of 0.090 inches based on the minimum core channel opening that the safety injection system (SIS) must pump. The UFSAR also states the containment spray system pumps and nozzles are capable of passing particles up to 0.25

inches (Section 6.2.2.1.2.5). The UFSAR and the RG treat the sides of the sump and the top of the sump as being fully submerged and discourage the use of a screen on top because debris may clog the screen. The inspector concluded that the clearances on the top of the sumps (up to 5 inches) could have allowed particles greater than 0.090 inches and greater than 0.25 inches into the sump, both during a postulated large break loss of coolant accident (LBLOCA) and during any normal maintenance activities performed in the area.

The licensee issued Licensee Event Report (LER) 50-362/93-010 on December 22, 1993. In this LER the licensee essentially considered that water level rise in the area of the sump during a postulated LBLOCA would be slow and water velocity would be low, and based on the material construction, condition, and cleanliness of containment it was not credible for debris to enter the sump via the LTOP opening discussed above, which was the largest gap. The inspector concluded that the probability of material entering the sump through the gaps in the top cover plate during a postulated LBLOCA was probably low.

Previous NRC Correspondence

The inspector reviewed previous notifications regarding containment sumps that the NRC had issued to the industry, and the licensee's actions with respect to those notifications. The NRC had issued several Information Notices (INs) (INs 88-28, 89-77, 90-07, 92-27, and 93-34), a Generic Letter (GL) (GL 85-22), and a Bulletin (NRC Bulletin 93-02). The inspector concluded that the main topic of these notices pertained to insulation materials and the potential for these materials to block the sump screens, and that the licensee's actions in response to the all except one of these notices were adequate. The inspector noted that IN 89-77, "Debris in Containment Emergency Sumps and Incorrect Screen Configuration," identified deficiencies in the sumps of three operating facilities, which included designs not in accordance with plant drawings and gaps in screens which could have resulted in introduction of debris large enough to have caused pump damage or flow degradation. The inspector concluded that this IN might have provided the licensee an earlier opportunity to discover the gaps in the top cover plate at the Units 2 and 3 emergency sumps.

2. Error in the Large Break Loss-of-Coolant Accident (LBLOCA) Analysis

The licensee informed the inspector on September 21, 1993, of an apparent error made by Combustion Engineering (CE) and accepted by the licensee in the original UFSAR LBLOCA analysis. Previously the licensee had requested that CE perform a new computer analysis, using updated computer analytical models, of the design basis LBLOCA accident for the Unit 3 Cycle VII core. CE and the licensee reviewed preliminary results and noted that the new peak clad temperature (PCT) generated reached 74 degrees higher than the UFSAR analysis, which was 2183° F (UFSAR Table 15.6-16). The error in the original analysis was a nonconservative data input error in a coefficient for paint thickness on components in containment. The effect of having a nonconservative coefficient (analyses used a paint thickness greater than actual) was to underestimate the amount of thermal energy absorbed by the components in containment. This resulted in a higher peak containment temperature and pressure, resulting in a higher core reflood rate based on initiating safety injection sooner, thus resulting in a lower PCT.

10 CFR 50.46 requires that PCT remain below 2200°F as an Emergency Core Cooling System (ECCS) acceptance criterion. After discovery of the error, the licensee reduced the allowable linear heat generation ratio (LHGR) for Units 2 and 3 from 13.9 Kw/ft to 13.4 Kw/ft in order to ensure acceptable initial conditions for the LBLOCA analysis and a resultant PCT below 2200°F. This was done by setting a core operating limits supervisory system alarm setpoint to this reduced value. The licensee requested that CE reevaluate the Unit 3 Cycle VII analysis to determine if the linear heat generation ratio (LHGR) in Technical Specifications of 13.9 Kw/Ft was valid, or if it would require adjustment down to 13.4 Kw/Ft.

The inspector reviewed Units 2 and 3 LER 93-007, dated October 21, 1993, CE correspondence to the licensee including the results of the reanalysis mentioned above, TS, and the UFSAR, and concluded that the Technical Specification LHGR limit of 13.9 Kw/Ft appeared to still be valid.

The inspector noted that some margins had been reduced to account for the paint thickness correction, most notably that 500 tubes per steam generator (SG) had been assumed plugged in the new analysis, as opposed to 1000 tubes plugged as shown in one of the original UFSAR analyses (UFSAR Table 15.6-14). The UFSAR analysis consisted of a range of possible initial conditions from no tubes plugged to 1000 tubes per SG plugged, along with changing other initial variables. The inspector noted that currently Unit 2 SGs had 277 (SG E088) and 369 (SG E089) tubes plugged, and Unit 3 SGs had 303 (SG E088) and 311 (SG E089) tubes plugged. The inspector also noted that the licensee submitted each core reload composition to CE for analysis, with the numbers of tubes currently plugged, after each refueling. The inspector had no more questions concerning the reduction of margins and considered the licensee's approach adequate.

The inspector concluded thi was a violation of 10 CFR Part 50, Appendix B, Criterion II which states that design control methods shall provide for checking the adequacy of design. However, the inspector concluded that the safety significance was low in that the original LHGR in TS was still valid, indicating that the ECCS acceptance criteria were always met. Additionally, the licensee informed the inspector that LHGR had never exceeded 13.4 Kw/ft from initial plant startup. The inspector concluded that this is not being cited because the criteria of Section VII.B of the Enforcement Policy were met (NCV 50-361/93-38-04).

The licensee informed the inspector that this error would be reported to the NRC via the annual report required by 10 CFR 50.46.

b. Use of Furmanite on Safety-Related, QC II Valve Contrary To Procedure (37702)

In response to events that occurred at Millstone Nuclear Power Station, Unit 2, the inspector requested that the licensee provide a list of all valves repaired using Furmanite in both Units 2 and 3.

On December 9, 1993, the licensee's engineering department (STEC) presented the inspector with a listing of 39 valves in Unit 2 in which Furmanite had been used. The licensee informed the inspector that there were no affected valves in Unit 3 because it was the licensee's normal practice to repair valves in which Furmanite had been used during outages, and Unit 3 was at the time in a refueling outage (Cycle VII). The licensee also stated that repairs with Furmanite to Unit 2 valves had been done after the startup from the previous refueling outage in August 1993. The licensee stated that there were no primary system pressure boundary valves or other components which had used Furmanite in either Unit.

The inspector reviewed the licensee's program for the control of Furmanite for valve repairs in procedures SO123-V-5.1, "Temporary Modification Control," and SO123-XXVII-20.13, "Furmanite Engineering Procedures." The licensee informed the inspector that a separate procedure would be developed to document the engineering evaluation before Furmanite use on any valve, and that this was anticipated to be completed by mid-February 1994. The inspector will review this procedure in a future inspection. Based on procedural review, the inspector considered the licensee's program adequate.

However, the licensee identified a safety-related valve (S21301MU1000) which had been repaired using Furmanite. The licensee's program requires that where Furmanite is used on a safety-related valve, a Nonconformance Report (NCR) is to be initiated to approve and document this action. The licensee stated that the NCR process would assure that the effect of Furmanite on safety-related components would be evaluated. However, as a result of the database search to address the inspector's questions, as well as the licensee's own initiatives, the licensee identified that an NCR had not been written for the Furmanite work on valve S21301MU1000, which was contrary to the licensee's program. The inspector reviewed procedure SO123-V-5.1 and noted that Step 6.3.1 required that an NCR be written to approve and document the Furmanite use on safety-related components. The inspector concluded the failure of the system engineer to initiate an NCR in accordance with Step 6.3.1 of procedure SO123-V-5.1 is the third example of a violation related to procedural adherence (Violation 50-361/93-38-01).

The inspector noted that the valve affected was one of two isolation valves on the main steam header to a steam trap. Although the valve was clearly indicated as QC II on the licensee's computerized material class systems and on applicable Piping & Instrument Drawings, the inspector concluded it was relatively unique in that it was downstream of another isolation valve. The inspector was informed that the cognizant engineer had noted this upstream isolation valve and assumed that valve S21301MU1000 was not safety-related. The licensee's after-the-fact review of the issue concluded that the use of Furmanite on the valve was acceptable.

The inspector also noted during plant tours that the attempted Furmanite repairs on S21301MU1000 were not successful, and that the licensee planned to replace this valve.

The third example of a violation and one non-cited violation were identified.

8. <u>Review of Licensee Event Reports</u> (92700)

Through direct observations, discussion with licensee personnel, or review of the records, the following LERs were closed:

<u>Unit 2</u>

93-011, Revision 0 — "Reset Of Low Steam Generator Pressure Setpoint In Mode 1."

Discussion of this LER is documented in Paragraph 3.3 of this inspection report, in connection with event followup inspection activities.

93-007, Revision 0 — "Calculated Peak Fuel Clad Temperature."

Discussion of this LER is documented in Paragraph 7.A.2 of this inspection report, in connection with event followup inspection activities.

No violations or deviations were identified.

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

   a. (Closed) Followup Item (50-206/93-11-12), "Maintenance Planner Workload and Staffing Assessment."

      In NRC Inspection Report 50-206/92-03, the licensee committed to perform an assessment of the maintenance planner workload and staffing in early 1992. This commitment was made to address deficiencies identified as a result of the inoperability of the Halon fire suppression system for the 4160 volt switchgear room for Unit 1.

      On January 31, 1992, the licensee's quality assurance (QA) organization issued an audit of maintenance planning at San Onofre Nuclear Generating Station (SONGS) Units 1, 2, and 3. The intent of the audit was to determine the effectiveness of maintenance planning and the impact of planning on the performance of maintenance production at SONGS.

      The inspector reviewed the audit and noted that conclusions were: (1) that feedback systems and interfaces between Maintenance planning and production needed improvement, (2) the need for additional training for Maintenance planners, (3) and the need to further evaluate planner work load and resources.

      The inspector discussed the audit findings with the Maintenance Manager. The inspector noted that recommendations made by QA to address the first conclusion, which was implemented by the Maintenance Department, were to increase the time allotted for and encourage more thorough planner walkdowns. The inspector determined that the Unit 1 Maintenance organization had initiated a program called "Partners for Success," to formalize feedback methods so that planners could upgrade the quality of work plans. In addition, the inspector noted that Maintenance Order (MO) quality control rejection information was trended to identify weakness and trends in the maintenance planning process. To address the second conclusion, Maintenance developed a "Planner's Guide" to help planners deal with the complex maintenance planning process more effectively. In addition, a five week planner's course was developed. Maintenance supervision indicated that all maintenance planners would be required to complete the course. To address the third conclusion, the Maintenance Department brought the supervisory function of the planners and production staff under common supervision to better coordinate the workload. The inspector considered the licensee's actions proposed and completed to address the QA audit findings adequate. This item is closed.

b. (Closed) Followup Item (50-361/93-05-03), "Core Protection Calculation Abnormalities."

On February 25, 1993, the licensee observed differences between the core axial power distribution calculated by their design code (CECOR), the core operating limits supervisory system (COLSS), and core protection calculators (CPCs) for both Units. CECOR and COLSS used the in-core neutron flux detectors, while the CPCs (input to the reactor protection system) used the ex-core detectors to calculate core axial power. CECOR and COLSS were observed to produce a saddle-shaped axial power distribution, while the CPCs produced a cosine-shaped curve. The licensee expected all three systems to calculate a saddle-shaped axial power distribution curve. The axial power distribution differences were observed during a data review performed by the licensee's Nuclear Fuels Analysis group as part of the licensee's expanded ability to review core performance data. The review identified that the calculated power at the top of the core as predicted by the CPCs was less that predicted by COLSS or CECOR. As a result, the licensee concluded that the departure from nucleate boiling ratios (DNBRs) calculated by the CPCs might have been non-conservative since the core power used in the DNBR calculation might be less than actual core power.

The licensee preliminarily considered the cause of the difference in the axial power distribution for the CPCs to be attributed to the methods used to develop the Shape Annealing Matrix (SAM). Corrective actions included inducing a power swing to develop a new SAM, and a re-determination of penalty factors for the CPCs of each Unit. On March 4 and March 6, 1993, power was increased to 100% after incorporating the new SAM into the CPCs for Units 3 and 2 respectively.

The inspector reviewed startup core physics data used to develop the SAMs, and penalty factors, and had no concerns. In addition, the inspector reviewed the licensee's root cause evaluation, as submitted to the NRC in a letter dated July 19, 1993, which was performed to determine the differences observed between the axial power distributions generated by the CPCs, COLSS, and CECOR. The inspector noted that the root cause of the CPC axial shape anomaly was that lack of coherent relationship between the normalized middle peripheral power integral and the normalized middle excore detector signal during the Fast Power Ascension (FPA) Program SAM measurement at beginning of core life (BOC). The breakdown in coherent relationship was concluded to be caused either individually or by a combination of incore deadband as implemented by the plant computer, manual collection of excore data, and a combination of fuel management effects of near zero isothermal temperature coefficient at BOC, relatively flat axial peak at BOC, and low leakage fuel management.

The licensee requested Asea Brown Boveri Combustion Engineering (ABB-CE) to evaluate the as-found condition of the CPCs to determine whether or not they met the appropriate criteria for operability during the previous operating cycles using the FPA program. The operability assessment performed by ABB-CE, contained in the root cause report, concluded that the Unit 2 and 3 CPCs were operable during Cycles III, IV, V, and VI (the cycles which used the FPA program), and the overall operation of the CPCs was conservative and within the current analysis of record for UFSAR events.

Corrective actions to prevent recurrence were implemented during the Unit 2 Cycle VII reload startup SAM measurement. The licensee stated that based on the results of the startup and subsequent axial shape monitoring during the cycle corrective actions could be modified during future startups. Specifically, the corrective actions included a reduction or removal of incore detector deadband, modification of the reload startup SAM measurement procedure, changing ABB-CE design code ROCS modeling for FPA simulation, modification of SAM measurement acceptance criteria, and the routine monitoring of CPC axial shapes.

The inspector considered the licensee corrective actions adequate. This item is closed.

No violations or deviations were identified.

10. Exit Meeting

On January 6, 1994, 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.