U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos.	50-206/93-26, 50-361/93-26, 50-362/93-26
Docket Nos.	50-206, 50-361, 50-362
License Nos.	DPR-13, NPF-10, NPF-15
Licensee:	Southern California Edison Company Irvine Operations Center 23 Parker Street Irvine, California 92718
Facility Name:	San Onofre Units 1, 2 and 3
Inspection At:	San Onofre, San Clemente, California
Inspection Conducted:	July 29 through September 1, 1993
Inspectors:	C. W. Caldwell, Senior Resident Inspector J. J. Russell, Resident Inspector D. L. Solorio, Resident Inspector C. M. Regan, Intern

Approved By: Chris Van Alyh for 9-27-93

H. J. Wong, Chief
Reactor Projects Section II

Date Signed

Inspection Summary

Inspection on July 29 through September 1, 1993 (Report Nos. 50-206/93-26, 50-361/93-26, 50-362/93-26)

Areas Inspected: Routine, announced, 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 maintenance activities, refueling activities, independent inspection, and followup of previously identified items. Inspection procedures 37700, 40500, 61726, 62703, 64704, 71707, 71710, 82301, 92701, 92702, 93702, and Temporary Instruction (TI) 2500/028 were covered.

Safety Issues Management System (SIMS) Items: None

Results:

General Conclusions and Specific Findings:

Strengths:

Overall, the inspectors considered the licensee's Nuclear Oversight activities to be a strength (Paragraph 7). The inspectors considered that the licensee was a leader for the industry in the area of risk management (Paragraph 7.e).

The inspectors considered the identification of a trend in reactor coolant pump speed pulse shaper calibration data and the subsequent generation of a non-conformance report a strength (Paragraph 7.G).

The inspectors considered the site Fire Department, which provided seven state certified full-time fire fighters on site for 24-hour shifts, a strength (Paragraph 7.h).

Weaknesses:

An NRC inspector identified a leak in the hydraulic control oil system for a Unit 2 main feedwater isolation valve. The inspector considered the licensee's failure to observe this leak prior to NRC observation a weakness (Paragraph 4).

The inspectors identified minor weaknesses in the areas of site housekeeping (Paragraph 3.a), radiological controls (Paragraph 3.b), confined space posting (Paragraph 3.c), and formal goals for Quality Assurance audit field time (Paragraph 7.c).

The inspectors observed minor weaknesses in the areas of control room communications (Paragraph 7.f.2) and in the preparation of radiological data (Paragraph 7.f.1) during the site Emergency Preparedness exercise conducted during the inspection report period.

The licensee had not fully considered preservation of root cause information when a damaged o-ring was replaced on a feedwater isolation valve. The o-ring was cut at the location that the o-ring was damaged (Paragraph 4).

Significant Safety Matters: None

Summary of Violations: None

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, Nuclear Oversight
K. Slagle, Deputy Station Manager
*+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
*+J. Fee, Assistant Manager, Health Physics
*W. Zintl, Manager, Emergency Preparedness
*C. Anderson, Supervisor, Emergency Preparedness
*C. Couser, Supervisor, Fire Protection
D. Herbst, Manager, Quality Assurance
+C. Chiu, Manager, Quality Engineering
G. Moore, Plant Superintendent, Unit 1
V. Fisher, Plant Superintendent, Units 2/3
*+G. Gibson, Supervisor, Onsite Nuclear Licensing
J. Reeder, Manager, Nuclear Training
H. Newton, Manager, Site Support Services
+D. Irvine, Supervisor, Technical Support
J. Winslow, Supervisor, I&C Engineering
R. Lee, Supervisor, Nuclear Safety Group
+W. Strom, Supervisor, Independent Safety Engineering Group
N. Maringas, Supervisor, Performance Monitoring
M. Trillo, Assistant Plant Superintendent
*+R. Giroux, Engineer, Onsite Nuclear Licensing
*D. Axline, Engineer, Onsite Nuclear Licensing
O. Thomsen, Manager, Nuclear Fuel Engineering & Analysis
R. Ashe-Everest, Supervisor, Nuclear Fuels Group
M. McDevitt, Nuclear Supervisor, Station Technical
R. Ramendik, Supervisor, Reactor Engineering
*+W. Frick, Assessment Supervisor, Nuclear Oversight Department
*J. Hirsch, Supervisor, Power Generation
*+A. Thiel, Manager Electrical Systems Engineering
*R. Joyce, Maintenance Manager, Units 2/3
*E. Bennett, Quality Assurance Engineer
+C. Brandt, Quality Assurance Engineer
+W. Marsh, Manager, Nuclear Regulatory Affairs
+J. Travis, Maintenance Manager, Unit 1
+R. Kaplan, Onsite Nuclear Licensing
+D. Schone, Project Engineer/Supervisor, Design Basis Documents
+D. Turner, Senior Control Room Supervisor

+P. Smith, Training Administrator, Nuclear Training Division

NRC

+C. Caldwell, Senior Resident Inspector, San Onofre
*+J. Russell, Resident Inspector, San Onofre
*D. Solorio, Resident Inspector, San Onofre
+J. Sloan, Senior Resident Inspector, Palo Verde
*C. Regan, Intern, NRR

San Diego Gas and Electric Company

*R. Erickson, Site Representative

* Denotes those attending the Resident Inspectors' exit meeting on September 1, 1993.

+ Denotes those attending an exit meeting with D. F. Kirsch on August 27, 1993.

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

The Unit was permanently shutdown on November 30, 1992. Primary and secondary systems remained in a "SAFSTOR" condition throughout the inspection report period.

Unit 2

The Unit began the inspection report period in Mode 5 in support of the Cycle VII refueling outage. The Unit was synchronized to the grid at 10:33 a.m. on August 8, 1993. The Unit operated at 100% power until August 30, 1993, when cold leg reactor coolant system (RCS) temperature was lowered to the middle of its normal operating bounds in order to minimize steam generator tube degradation. The resultant decrease in main steam pressure resulted in decreased main turbine power output, and reactor power stabilized at 98%. The Unit operated at 98% power through the end of the inspection period.

Unit 3

The Unit began the inspection report period at 100% power, and operated at full power until August 30, 1993, when RCS cold leg temperature was lowered as in Unit 2 and reactor power stabilized at 98%. The Unit operated at 98% power until August 31, 1993. At that time the Unit

downpowered to 80% power to support a heat treatment of the circulating water system. The Unit remained at 80% power through the end of the inspection period.

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.

a. Equipment Floor Drain Covers Missing In The Unit 2 Safety Equipment Building

On September 14, 1993, the inspector noted three missing floor drain covers in the Unit 2 safety equipment building (SEB) Room S2-003. In two instances debris, including tools, were visible in the drains. The inspector was concerned that this was not in accordance with management expectations as described in procedure SO123-XVIII-23, "Implementation of Site Housekeeping and Cleanliness Controls," Section 6.4.1.2.2, which stated, "Floor drains should be clean and grating covers in place." The licensee removed the debris from the drains and reinstalled the missing covers.

The inspector considered the safety significance of the debris in the floor drains minimal, since no credit was taken for operation of the floor drains in the flooding analysis projected in the Unit 2 and 3 Updated Final Safety Analysis Report (UFSAR), Section 3.4.2.2.2.

The licensee Vice President, Nuclear Generating Station, indicated that in the future, control of the floor drain covers would be improved by enhanced compliance with site housekeeping practices.

b. Degraded Radiological Controls In Units 2 And 3

The inspector observed three instances of degraded radiological controls in Units 2 and 3. In each case, the licensee took prompt action to correct the deficiency. The inspector concluded that these instances were isolated and noted that radiological controls were, in general, adequate.

On August 3, 1993, the inspector observed a yellow laboratory coat hanging half-in and half-out of a posted surface contamination area. The area was around Unit 3 charging pump 3P-192. The inspector was concerned that, if the coat was contaminated, the contamination could spread outside of the posted boundary. In addition, the

inspector noted that an individual could brush up against the coat and become contaminated without entering the contaminated area. Licensee Health Physics (HP) personnel placed the coat entirely in the contaminated area.

The inspector observed two instances of degraded radiological postings. One instance was a radiation area posted on the 37 foot level of the Unit 2 radiological waste building (RWB) on August 3, 1993. The area was entered through a door adjacent to the Unit 2 primary water makeup tank from a stairwell, and was located outside the RWB. The radiation area posting that was meant to be strung across the open door had fallen, along with the yellow and magenta rope that it was hanging on. Thus, it appeared that the posting had been removed, and the area de-posted. The inspector questioned HP personnel, who informed the inspector that the area was required to be posted. Licensee personnel reposted the area.

The inspector observed the second instance on August 4, 1993. This instance involved a high radiation area posted adjacent to the Unit 2 component cooling water pump (2P025) room. The inspector noted that the deck grating immediately in front of the entrance to the pump room contained a posting sign lodged half-in and half-out of the deck grating. The inspector notified HP personnel, who secured the posting back on the wall near the pump room, to indicate the high radiation area.

Although the inspector concluded that the instances mentioned above were of minor safety significance, the adequacy of radiological postings will be reviewed during future inspections.

c. Unit 2 Walkdown Prior To Mode 2 Entry

The inspector walked down Unit 2 on August 4, 1993, immediately prior to Mode 2 entry. The inspector observed the following:

- One confined space that was not properly posted. The space was located on the 17 foot elevation in the cable spreading room. The space had two ladderways that could be used for access. One ladderway had a confined entry tag on it, indicating the last date the space had been monitored for habitability. Neither ladderway was posted as leading to a confined space. The licensee agreed to mount permanent confined space posting for this area.

- Loose tools and debris were found in the emergency chilled water train "B" room (117) and in the normal chilled water room (116). The licensee removed the tools and debris.

- An oil leak was found on the 2G002 emergency diesel generator soakback oil pump suction. The licensee initiated a maintenance order (MO) to repair the leak.

- An oil leak and damaged insulation was found on motor-driven auxiliary feedwater pump 2P504. The licensee made the appropriate repairs.

- Some debris was noted in electrical cableways, for example in cableway AXBWA7. The cableways were cleaned. The licensee agreed to include cableways in the areas that electricians would monitor as they did walkdowns for fire hazards.

- Water was found in the low pressure safety injection pump 2P015 sump. The water was coming from valve MU015, due to a packing leak. The licensee planned on replacing the packing on the valve in order to stop the leak.

- A buildup of Calgon was found on component cooling water valve 2HV6551. The licensee cleaned the Calgon off the valve and inspected the valve for packing leaks.

- The inspectors identified eighteen maintenance orders with deficiency tags remaining on Unit 2 equipment after the completion of the recent refueling outage. The inspectors discussed the reason for not resolving the deficiencies prior to Unit restart with the Maintenance Manager. These questions were adequately resolved and the inspector had no further questions.

The inspector considered that the licensee adequately addressed the above items.

d. Crew Staffing Audit

The inspector performed an audit of the Unit 2 and 3 crew staffing plan for the period of May 17, 1993, through January 23, 1994. During the Unit 3 Cycle VI refueling outage, a crew consisting of one "junior" Senior Reactor Operator (SRO) and one "junior" Control Operator (RO) had generated an unusually high number (i.e., three in one quarter) of Operation Division Experience Reports (ODERs). "Junior" being defined as having less than one year of experience in that position. The licensee then separated this crew and replaced the less experienced crew members with more seasoned personnel. This stopped the rapid generation of ODERs. Subsequently, the licensee had instituted a policy of "not routinely" scheduling a junior RO with a junior SRO during an outage. Because the policy was informal, the inspector was concerned that future crew staffing may not conform adequately to the new policy.

The inspector noted that crew "E" was the only crew in which it was possible to schedule a junior SRO with a junior RO. The shift staffing history showed three instances, for a total of 10 days, in Unit 2 during the Unit 2 Cycle VII outage, in which a junior SRO and a junior RO were teamed together on the same Unit during the same

shift. The inspector concluded that the licensee has sufficiently addressed concerns in this area.

e. Spent Fuel Pool Cooling System Walkdown - Unit 2

The inspector performed a walkdown of portions of the Unit 2 spent fuel pool (SFP) system to verify system valve alignments and equipment operability in accordance with station operating procedures.

The inspector reviewed procedures S023-3-2.11, "Spent Fuel Pool Cooling System Operating Procedure" and S023-0-17, "SFP System Administrative Technical Specifications and Locking of Safety-related Critical Valves and Breakers." P&IDs 40122BS02 and 40122CS02 and Isometric diagrams S21291ML018 and S21219ML077 were also reviewed. The inspector noted no deficiencies.

No violations or deviations were identified.

4. Evaluation of Plant Trips and Events (93702)

a. Hydralic Fluid Leak in Main Feedwater Isolation Valve (MFIV)

Leak Identification

On August 18, 1993, during a routine plant walkdown of the Unit 2 E089 main steam insolation valve (MSIV) area, the NRC inspector noted a hydraulic fluid leak coming from the "A" train solenoid pilot-operated dump valve, 2HY4052X2, for main feedwater isolation valve (MFIV) 2HV4052. The inspector notified the control room and an operator was dispatched to investigate the circumstances. The operator assessed the leak and initiated licensee actions to repair the leak.

The licensee notified the site Fire Department, who arrived at the scene promptly to contain the spill created as a result of the leaking hydraulic fluid. The inspector noted that there was no piping in the vicinity that were hot enough to vaporize the hydraulic fluid and cause a potential toxic fume hazard.

Potential Impact on Plant Operation

The inspector estimated the leak rate to be approximately 1 to 1½ gallons per hour. This was confirmed by maintenance personnel who had arrived to assess the leak. Maintenance personnel added fluid to the hydraulic skid 2HV4052HYD reservoir to maintain an inventory such that hydraulic pressure would not be lost in the system. Low hydraulic pressure would result in the closure of the MFIV and a resultant Unit trip. The licensee stationed maintenance personnel at the hydraulic skid to periodically add hydraulic fluid to maintain the level in the reservoir, and to monitor the leak.

System hydraulic pressure is maintained by automatic cycling of one hydraulic oil charging pump to maintain pressure between 1900 and 1750 (+/-50) psig. If system pressure falls below 1600 (+/-50) psig a second pump starts. A trouble annunciator alarms in the control room when system pressure reaches 1450 (+/-50) psig, and a local trouble annunciator alarms when reservoir level is low. System pressure was maintained within the operating band during the event.

The inspector reviewed design calculation S023-507-6-2-3-2 and design drawing S023-507-6-2-40, Revision 0. The inspector noted that reservoir T326 had an internal free volume of 200 gallons, and that at all times there was a total of approximately 60 gallons of hydraulic fluid in the control system. This included the reservoir, the MFIV actuator bell housing, the two charging pump accumulators, and the system piping. With the MFIV in an open position there was approximately 40 gallons of hydraulic fluid in the reservoir. The charging pump and recirculation pump suction lines draws from the reservoir 5½ inches from the bottom of the tank. Based on the information provided, there was approximately 16 gallons of unusable hydraulic fluid in the reservoir that lay below the suction lines for the hydraulic charging pumps. This left approximately 24 gallons of useable fluid in the reservoir under normal operating conditions. From an interview with the maintenance worker refilling the reservoir, the inspector concluded that approximately 15 gallons of hydraulic fluid was needed to bring the level of fluid in the reservoir back to within the normal range. Therefore, if the leakage remained at 1 to 1½ gallons per hour the control system would have become voided from within in approximately six to nine hours.

The inspector estimated that with a leak rate of 1 to 1½ gallons per hour, with the reservoir approximately 15 gallons below the normal level indication, the solenoid dump valve may have been leaking for approximately ten hours. The inspector noted that there had been several some opportunities for plant personnel to observe the hydraulic oil leak. These included shiftly operator rounds, and the maintenance personnel and the system engineer walking by the MFIV about the same time as the NRC inspector.

Troubleshooting and Maintenance Repair

The inspector observed licensee troubleshooting and maintenance activities on August 18 and 19, 1993. The licensee's initial assessment was that a rubber O-ring between the solenoid valve base and the valve housing was leaking. The inspector observed the licensee's first attempt to stop the leak by retorquing the solenoid valve base first to 15 ft-lbs and then when the leak continued, to 20 ft-lbs. The inspector noted that the machinist performing the work stated that it appeared the O-ring was seated incorrectly. These attempts were unsuccessful at stopping the leak.

The licensee performed further analysis of the leak to insure that by performing more extensive work on the solenoid dump valve and the resultant loss of fluid from the valve would not cause the MFIV to close, causing a reactor trip. The licensee generated M093081326000, "Serious Hydraulic Leak on Dump Solenoid Unit Trip Hazard," to perform the repair work. When questioned the licensee stated that upstream of the solenoid valve between the hydraulic charging pumps and the dump valve was a restricting orifice which would limit the pressure at the solenoid valve and also minimize the amount of fluid that would be lost during the work evolution. During the tailboard meeting, the inspector questioned the licensee regarding what the contingency plan would be if they were unable to reinstall either the new or the old solenoid valve. The licensee determined that a rubber gasket and a machined metal plate, attached over the open hole in the valve housing with a "C" clamp where the solenoid valve had been removed, would be sufficient to stop any further hydraulic fluid leak.

The inspector also noted that the control room supervisor, after approving the repair activities, conducted a tailboard with the COs and reviewed possible indications to expect in the event of an MFIV closure, and at what point a manual reactor trip would be warranted if operators were unable to recover steam generator level. The inspector considered this tailboard a strength.

During the work evolution the machinist that performed the work did not remove the solenoid valve entirely. The licensee removed the old rubber O-ring and replaced it with a new part. This was performed successfully by stretching the new O-ring over the valve base. The solenoid valve base was retorqued to 20 ft-lbs, the solenoid electrical cable installed, and the valve energized. At that time no leak was observed. The licensee sent the old O-ring off for chemical analysis in order to determine the failure mechanism. During the remainder of the inspection period the inspector periodically verified that the solenoid valve was not leaking.

The inspector reviewed the valve's maintenance history, which showed that no recorded work had been performed previously. Subsequently, the licensee scheduled maintenance during the Unit 3 Cycle VII outage to replace the O-ring by fully removing the dump solenoid valve and installing a new O-ring without stretching it.

The licensee stated that the chemical analysis was not likely to reveal any conclusive evidence since, during removal, the O-ring was cut in the location that the degradation had occurred. This appears to be a weakness in the maintenance planning for the work in not considering possible root cause evaluations to be conducted after the repair work was completed.

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)

M093012862001,	"Unit 2 ASME Section XI Hydrostatic Leak Test Of Pressurizer Weld At 6" Weld Neck."
M093040173000,	"Replace/Install Actuator For 2PV0100A, Unit 2 Pressurizer Spray Valve."
M093071899000,	"During Performance Of M093071839 Found Flex Conduit for Auxiliary Feedwater 2MP504 Outboard Bearing Thermocouple To Be Broken. Needs To Be Replaced."
M093080556000,	"Pump Outboard Bearing Oil Contaminated As Observed Through The Housing Sightglass."
M093080558000,	"Remove/Install The Thermocouple(s) In Support Of Outboard Bearing Disassemble Under M093080556000."

No violations or deviations were identified.

6. Engineered Safety Feature Walkdown (71710)

The inspector reviewed procedures S023-2-4, "Auxiliary Feedwater System Operating Procedure," and S023-0-17, "Locking of Safety Related Critical Valves and Breakers." In addition, the inspector reviewed P&IDs 40141CS03, 40141DS03, 40141ES03, 40160BS03, and 40160DS03. The inspector performed a walkdown of portions of the Unit 3 and Unit 2 AFW systems to verify system valve alignments and equipment operability in accordance with station operating procedures.

The inspector noted a deficiency tag (M093032098000) on motor-driven AFW pump S31305MP141 dated March 21, 1993, stating excessive seal packing leakage from the inboard shaft seal. However, the inspector also noted seal packing leaks of equivalent or greater volume from the Unit 3 AFW pump S31305MP504 inboard shaft seal and the Unit 2 AFW pump S21305MP141 inboard and outboard shaft seals that were untagged.

The inspector noted that there was no definition of excessive seal leakage defined in maintenance procedures, and that evaluation of packing leakage by the Operations and Maintenance Departments was not being performed consistently. The inspector noted that the AFW pump vendor manual (No. S4520) did not specify criteria to judge seal packing leakage. The cognizant engineer for the AFW system stated that seal leakage would vary according to the temperature of the seal and the packing. The colder the seal packing the more leakage was expected.

Past maintenance experience had shown that reduced leakage by over-tightened packing would cause premature packing failure. Maintenance was required by procedure to reduce packing leakage to a minimum of 1 drop per second when the pump was at normal operating temperature to maintain adequate seal cooling.

The inspector concluded that, based on inservice test results, the AFW pumps remained operable despite the pump leaks mentioned above. The inspector also concluded that the inconsistency in identification of packing leakage was due to an inconsistency in expectation from Operations personnel. The Maintenance Manager informed the inspector that maintenance personnel reviewed packing leakage, with the pump operating, as described above. The inspector considered this practice adequate.

No violations or deviations were identified.

7. Independent Inspection (37700, 40500, 62703, 64704, 82301, TI 2500/028)

a. Nuclear Oversight Organization (40500)

The licensee's Nuclear Oversight activities are accomplished by four functions. These are Nuclear Safety Engineering (NSE), Site Quality Assurance (QA), Site Quality Control (QC), and Supplier Quality Assessments.

1. Nuclear Safety Engineering

This organization consists of the Independent Safety Engineering Group (ISEG), Human Performance Evaluation Group (HPEG), and the Nuclear Safety Group (NSG).

This organization performs two types of Root Cause assessments: Component Failures, which are used to analyze hardware problems; and Division Investigation Reports (DIRs), which are used to analyze human performance, process, or program-related problems.

a) Independent Safety Engineering Group Activities

The inspector examined the activities and staffing of the ISEG organization and discussed the day-to-day functions with some ISEG members. Selected ISEG reports for the last year were reviewed. The activities conformed to TS requirements and the reports demonstrated substantial assessments of problem situations, specific supportable root causes and problem identifications, and provided comprehensive corrective action recommendations. ISEG recommendations were tracked to resolution, implementation was verified, and the effectiveness was assessed for the most important recommendations.

The ISEG staffing and experience level exceeds the TS requirements. The high level of expertise and experience in ISEG enables the ISEG staff to perform a substantial amount of independent testing in support of root cause determinations.

Based upon the inspector's examinations it was concluded that ISEG performs a substantial contribution to the oversight function at San Onofre.

b) Human Performance Evaluation Group Activities

The HPEG function is to reduce the Nuclear Organization's rate of human errors and mitigate the consequences of human errors. To perform this function the group: (a) performs root cause analyses and human performance evaluations of administrative programs, plant events and conditions; (b) helps other plant organizations perform high quality performance evaluations through a DIR coaching program; and (c) participating in human performance related programs and processes. In addition, the HPEG group oversees the licensee's Nuclear Safety Concerns (Hotline) program.

The inspector sampled and examined some of the assessments performed by HPEG and found them to be substantial and resulting in several recommendations for improvement.

c) Nuclear Safety Group Activities

The NSG performs activities as required by TS 6.5.3 and implementing procedure QAP N2.21, "Nuclear Safety Group." The activities performed include: conducting independent reviews; performing an oversight function of plant risk; and performing risk management assessments in support of operations, maintenance, design, licensing and training.

In the area of plant risk oversight, NSG performs: quarterly assessments of overall plant risk; risk assessments of refueling outage plans; and risk assessments of unusual conditions or operations.

NSG tracks changes in overall plant risk as a function of equipment outages due to all causes and publishes a quarterly report for senior management of the affect on core damage and radioactive release frequency. The inspector reviewed the results of this assessment and considers this activity to be a significant indicator of the effectiveness of oversight activities and management.

NSG performs risk assessments of all refueling outage plans. NSG had developed a full scope level 1 PRA of

shutdown conditions based upon the Individual Plant Examination (IPE) and used this methodology for the Units 2 and 3 Cycle VII outages. This activity represents a significant initiative by licensee management to better assess and control refueling outage risk exposure.

When warranted, NSG performs risk assessments of unusual plant conditions or operations and advises management of the advisability of performing or entering unusual activities or conditions. This appears to be a significant initiative to minimize risk significant events.

NSG had established a record of using risk management techniques to advise and support engineering, plant operations and maintenance, operator training and plant licensing. The inspector discussed specific examples with NSG supervision and found these to demonstrate the commitment to establish a risk-oriented culture at San Onofre. In support of this commitment, NSG had conducted training seminars for management and supervision to explain risk management and the techniques available to support day-to-day activities. In addition, NSG had established and published a listing of the most risk significant plant components for use by operations and maintenance personnel.

The licensee was in the final stages, with NUS Corporation, of developing a "Safety Monitor." This is a near real-time risk calculator combining a streamlined, complete 2000-basic event IPE model with the fastest available fault tree calculational algorithm. The inspector observed use of this computer system, with several examples of out-of-service components. The system performed risk calculations in as little as about 90 seconds. This system will provide the ability to make accurate and immediate risk management decisions based upon actual or hypothetical plant configurations. The inspector found this initiative to represent the significant commitment by plant management to control risk and safely operate the facility.

The inspector concluded that San Onofre was a leader for the industry in the area of risk management.

d) Quality Assurance Organization

The inspector examined the activities of the site QA organization to assess the contribution of quality assurance to plant safety.

The site QA organization was based upon functional disciplines: Operations, Technical Services, Maintenance, Quality Programs, and Performance Monitoring. The organizations appear to be adequately staffed, with several members from the line organizations. The combination of field experience and staffing augmentation from site functional groups results in a capability to perform real-time, in-depth assessments of station organization performance.

The Nuclear Oversight Division (NOD) provides quarterly reports to senior management by means of a comprehensive Quarterly Performance Assessment Report. The inspector reviewed two of the most recent reports and found them to be highly self-critical assessments of the state of affairs in all nuclear-related divisions.

The focus of the QA organization was to provide an increased level of field observation time by the QA staff so that problems could be identified and corrected, through the Field Corrected Error process, before the errors resulted in rework or rejection of the work activity. The enhanced level of field monitoring was a major new initiative. However, the inspector observed that the licensee had not established formal goals for auditor field-time, nor had a process been established to monitor whether or not the management expectations for this major initiative were being met. The thrust of this initiative was clearly to improve the level of performance-based assessment; as such, the initiative was well-conceived and considered. The effectiveness of this initiative was assessed by licensee management through an informal process of monitoring the number and types of problems found during the field monitoring process.

The licensee had defined several areas of emphasis. Primary among these were the problem situations found in organizational interface effectiveness, performance of first-line supervision in the control of contractor personnel, control of rigging equipment, and control of weld filler material.

The inspector examined examples of QA activities, particularly the special Instrumentation and Control maintenance assessment. The inspector found these to be creditable assessments resulting in substantial findings and recommendations for improvement.

e) Trending Program

The licensee had established a site-wide trending program for discrepant situations. Nuclear Safety Engineering

(NSE) had established a process for collecting and analyzing the data from audits, assessments, root cause investigations and other types of reviews which identify problems. The Organizational Common Cause Analysis process analyzes problem data for trends and monitors the Nuclear Organization to determine if individual problems may indicate common organizational causes. These analyses have indicated that programmatic deficiencies continue to be a major source of problems; the licensee was devising and implementing action plans to deal with this problem.

The trending program was used to analyze trends over the entire year and present the results of the analysis in the form of color-coded annunciator windows depicting the relative performance of organization personnel, programs, and system and equipment performance. This graphical presentation provides management with a quick visual assessment of the state of affairs and trends within each area of analysis. The inspector considered the trending program and methods to report the effectiveness of people, programs and hardware to management a significant improvement initiative.

b. Design Basis Documentation Program (37700)

The inspector examined the status of the licensee's Design Basis Documentation (DBD) program, sampled the completed DBDs and compared the contents to the guidance of NUREG 1397.

The licensee had issued 20 Unit 2/3 DBDs and had established controlled document locations for them. Another 13 DBDs were in the revision process and ten more were in the preparation process. The licensee anticipates completing the DBD effort by the end of 1994.

The licensee established DBD file locations in various places to make the DBDs available to those organizations most needing them. Five user-controlled locations have been established, and five Corporate Document Management organization revision controlled locations have been established. The DBDs are kept up-to-date, with design change notices, on a master computer file, and hard copies are distributed to the file locations.

The inspector sampled and examined certain aspects of the DBDs for the auxiliary feedwater (AFW) system and the plant protection system. The inspector found these DBDs to conform to applicable regulatory guidance and contain the information necessary to users (such as Engineering, Operations, and Maintenance). The information was clearly organized and presented, and references to basis documents were clearly identified and presented.

The licensee had established a verification and validation (V&V) program which included plant system walkdowns and operating,

surveillance, Emergency Operating Procedure (EOP), and Maintenance procedure reviews to assure that the as-built system and interfacing procedures conformed to the design basis.

Open items generated during the DBD preparation and V&V process were tracked and managed to closure. The inspector examined a sample of the listing of problems and issues identified during the course of DBD generation. It was clear that the DBD efforts contributed substantially to improving plant safety.

c. Problem Reporting System (40500)

The inspector examined two aspects of the licensee's problem reporting system; specifically nonconformance reports (NCRs) and site problem reports (SPRs). The backlog of open reports in each category had, within the last 18 months to two years, been reduced significantly (from approximately 2000-3000 to approximately 700-800 for each category).

The inspector examined the open NCR tracking system and observed that of the 825 open NCRs, the bulk were in the "waiting to be worked" category (580) and the "waiting on completion of cause and corrective action" to preclude recurrence specification (133). The others were spread throughout the inception to closure process. The bulk of the NCRs were in the maintenance area, waiting to be worked.

NCRs specifying accept-as-is or rework are reviewed by ISEG for acceptability of root cause specification or action to prevent recurrence.

The NCR process generally applies to safety-related activities or equipment and was broadly applied to include all safety-related activities from programs and procedures through equipment problems. The NCR process does not include a prioritization system; all those affecting operability of TS systems and components are worked off, through the phase necessary to restore system or component operability, within the time period allowed by the TS Limiting Condition for Operation.

The inspector examined the licensee's program for trending instrumentation out-of-calibration findings and concluded that the licensee had instituted sufficient controls to preclude instruments drifting beyond the analytical limits of the safety analysis. Generally, the licensee's controls prevented drift beyond the allowable tolerance limits (the allowable limit is always less that the safety analysis limit). The licensee had established criteria for writing NCRs on instruments found out-of-tolerance which assured that the safety analysis limits were not breached. The inspector observed that this system contained a weakness in that the trending system would not capture, for management and engineering attention, situations wherein instruments might be frequently found out-of-

calibration to an extent less that the criteria established for issuing an NCR.

The licensee uses the SPR program to document problems applicable to nonsafety-related equipment and processes and some very minor safety-related deficiencies (such as safety-related drawings which need revision). SPRs are prioritized by a board. Issues important to safety are generally dealt with on short notice during the morning meetings as an immediate work item. The priority system currently uses the MO prioritization system, which is not wholly applicable to problem reports. Therefore, a team was working on a new prioritization system which will effectively deal with engineering work. The licensee had recently completed a review of all open SPRs to assure that nonconformance report type conditions were not included in the SPR system.

The Station Technical organization is working to define a self-assessment plan by the end of 1993, as required by the licensee's Business Plan.

d. Core Reload Design (37700)

The inspector examined the licensee's core reload design activities, by discussion with licensee personnel and examination of licensee documents, to assess whether or not the licensee was conducting those activities in a manner conforming to specified requirements and good engineering practices. The also inspector examined the Unit 2 Cycle VII core reload report and the safety analysis of the report.

The licensee contracts with ABB-CE for all reload design analysis work. The interface with the contractor is not formally specified, but occurs through the CE Project Manager and by frequent telephone calls with the contractor. When there are major technical changes in the design, the licensee generally performs a technical audit of the contractor's design facility. For equilibrium cycle fuel management there are no major changes and, therefore, the level of licensee oversight is lower. The licensee had obtained NRC approval of a topical report, allowing them to do all physics-related calculations, a capability which is utilized to check the contractor's calculations.

The licensee performs quality oversight of the fuel manufacturer's facility during the fuel manufacturing cycle and audits fuel receipt by inspection. Engineering performs reviews of all contract documents such as fuel drawings, schedules and the reload report. The licensee had instituted several checks to verify core reload in accordance with the approved core map. The startup test program verifies certain thermal/hydraulic and nuclear characteristics, for example: reactivity coefficients, critical boron concentrations, rod worth measurements, power distribution measurements at various power levels, linear heat rate and departure from nucleate boiling

ratio (DNBR) measurements, and a weekly snapshot of core power distribution.

e. Employee Concerns Program Survey - Units 1, 2, and 3 (TI 2500/028)

In accordance with the instructions of TI 2500/028, The inspector performed a survey of the licensee's employee concerns program and documented the results on the attached survey form. The inspector reviewed Nuclear Engineering, Safety & Licensing procedure NES&L39-2-1, "Nuclear Safety Concerns," and interviewed responsible personnel. The results of this effort are provided as Attachment A to this inspection report.

f. Evaluation of Emergency Preparedness Exercise - Units 2 and 3 (82301)

The inspector observed the actions of the control room staff in operating the plant simulator during an Emergency Preparedness (EP) exercise conducted on August 11, 1993. The inspector assessed the performance of the staff as they implemented procedures, analyzed plant conditions, classified the event, and communicated with other organizations. The inspector also observed the critique conducted after the exercise by drill participants and licensee staff.

The exercise began at 8:00 a.m., with a loss of control of radioactive material in the radiological waste building. The Shift Superintendent assumed the duties of the Station Emergency Coordinator (SEC) and declared an ALERT. Then, an operator, who had tested positive for drugs during random drug screening, refused to leave the Protected Area. The operator hid in the turbine building, necessitating a search by Security personnel. The operator was apprehended later in the exercise. At 9:00 a.m., the Shift Superintendent turned over SEC duties to the licensee Vice President, Nuclear Generating Station.

At 9:35 a.m., one control element assembly (CEA) inadvertently dropped into the core. The operators reduced turbine power and attempted to raise the dropped CEA. At 10:10 a.m. the CEA ejected from the core due to a failure of the CEA nozzle. This caused a small break, loss-of-coolant accident. Safety injection and containment isolation automatically initiated. The ejected CEA also caused approximately 10% of the total fuel cladding to fail. The scenario had begun with a 10.2 gallon per day steam generator tube leak. This failed fuel caused the air ejector wide range gas radiation monitor (WRGM), RE-7870D, to alarm. The leak rate was unchanged. However, the increased primary activity caused the WRGM to read 2000 microcuries per second, an increase of 100,000 times the normal reading. The operators entered procedure SO23-12-9, "Functional Recovery," and isolated the leaking steam generator. Due to an electrical ground, one of the electrical penetrations into containment was damaged and containment integrity was lost. The

scenario ended as the operators initiated shutdown cooling of the RCS at 1:25 p.m.

The inspector observed the performance of the operating crew during the exercise, and concluded that the crew had effectively mitigated the event to the extent allowed by both licensee controllers and equipment availability. While the Shift Superintendent held SEC duties the inspector concluded that he had adequately implemented the Emergency Plan.

The inspector noted two areas of minor concern. Both areas were also identified by licensee evaluators, as described below.

1) Radiological Data

Radiological data was presented to the operators on a computer screen adjacent to the simulator. The licensee had prescripted this data so as to provide real-time, consistent data to all facilities operated by the Emergency Response organization. This data showed air ejector WRGM (RE-7870D) increasing to 2000 microcuries per second, as noted above. This reading remained elevated and constant for approximately 1 hour and 25 minutes. However, immediately after the CEA was ejected, containment pressure rose and containment isolation was automatically initiated. This isolation shut both main steam isolation valves (MSIVs). Although some residual activity might have made the WRGM have an elevated reading, the inspector concluded that a sustained 100,000 times normal level increase would not have occurred. This was because the MSIVs were shut, blocking all sources of radioactive steam to the turbine, and hence to the condenser. This elevated reading proved confusing for the operators during the course of the scenario. During the licensee critique it became apparent that the licensee had not adequately reviewed the effect that the MSIVs going shut (on the containment isolation signal) would have on the WRGM indication. The inspector concluded that the operators' confusion was subsequently alleviated during this critique and that their anticipation of actual plant response was adequate. However, the inspector also concluded that the licensee should have adequately reviewed the scenario so as to provide accurate radiological data, specifically the WRGM indication.

The inspector interviewed the EP Manager, who informed the inspector that EP had developed and reviewed the scenarios. The EP Manager also stated that the scenario review was conducted, in part, by Senior Reactor Operators (SROs) that were on his staff. The EP Manager agreed to continue to emphasize review of radiological data prior to scenario implementation. The EP manager further agreed to continue to emphasize the use of Senior Reactor Operators, on his staff, to review radiological data with an emphasis on anticipated

automatic plant response. The inspector considered these actions adequate.

2) Communication

In certain instances during the scenario, communications were not in accordance with procedure S023-0-44, "Professional Operator Development and Evaluation Program." Attachment 4 to this procedure specified a repeat-back of information for common understanding. The inspector noted that "O.K." was used occasionally as a repeat-back of plant relevant information, or to acknowledge common understanding of direction given to Reactor Operators by SROs. Occasionally no verbal acknowledgement was given. The inspector had also noted weak communication of the type mentioned above, during operation of the controls in the actual plant. These observations were made during the inspection report period and included observations of the operators borating and diluting the Unit 2 RCS, and Unit 2 reactor startup.

The inspector also noted that weak communication practices had been observed by NRC Region V Licensing Examiners during the last NRC requalification examination administered to Units 2 and 3 in January 1992. These weak communication practices had been documented in Examination Report No. 50-361-OL-92-01. At that time, the licensee replied to Region V in a letter dated April 3, 1993, that the area of communications would be improved by improving the enforcement of good operating practices on communications during training on the simulator. Further, the letter stated that these good operating practices would be incorporated into various lesson plans and would be evaluated for effectiveness during 1992.

The inspector interviewed the Nuclear Training Division (NTD) requalification training manager. The manager informed the inspector that the corrective actions to improve communications had been completed. The manager stated that operator communications had improved since the NRC requalification examination in 1992, although he also stated that the area of communications could be improved further. The NTD manager agreed to continue to stress the area of communications during licensed operator continuing training. The inspector noted that an NRC requalification examination was scheduled for the licensee in January 1994. The inspector noted that licensee performance in the area of communications would be reevaluated by NRC license examiners at that time as a part of the normal NRC requalification process. The inspector had no further questions in this area.

g. Maintenance Activity Review - Units 2 And 3 (62703)

The inspector noted two areas of concern during the course of review of maintenance activities in Units 2 and 3. These are described below:

1) Reactor Coolant Pump Speed Sensing Pulse Shapers

The pulse width for the reactor coolant pump (RCP) speed sensor input to the Core Protection Calculators (CPCs) is set by a pulse shaper. This pulse shaper receives an input from speed sensors attached to each RCP. Each CPC had four pulse shapers, one for each RCP. The pulse shaper changes the speed signal from the RCP speed sensor to a pulse, and these pulses are then counted, providing RCP speed to the CPCs. This information is used as an indication of total core flow for the DNBR low reactor trip. The calibration of the pulse shapers is checked once per refueling outage. The inspector reviewed the calibration data for Unit 3 CPC channel "C" for the last three Unit 3 refueling outages. The inspector noted that the as-found pulse width was not in specification for any pulse transmitter during the Unit 3 outages in 1988 and 1990. The inspector noted that the technicians adjusted the width to center-of-band (100 micro seconds) during each of these calibrations. The inspector concluded that, with the specification being 100 plus or minus 3 microseconds, the as-found widths of approximately 108 in 1988 and 93 in 1990, were of no safety significance. This was because deviations in width of such a small amount compared to total width would not cause the circuitry to count too many, or too few, pulses. Thus, an accurate representation of RCP speed would be maintained.

The licensee initiated NCR 92020220 during February 1992 to address the high number of incidences that the pulse shapers were found out of calibration, as described above. The inspector noted that the NCR disposition was to accept an as-found pulse width of 100 plus or minus 10 microseconds as in calibration. However, the technician was to leave the as-left pulse width at 100 plus or minus 3 microseconds. The NCR safety evaluation concluded that widths as narrow as 70 microseconds or as broad as 130 microseconds would still result in accurate RCP speed indication to the CPCs. However, the inspector noted that disposition step 2 of the NCR stated, "Revise I&C procedure S023-II-9.219 (Bently Nevada Reactor Coolant Pump Shaft Speed Sensing System Pulse Shaper Calibration)...to incorporate the following acceptance criteria for "as-found" data for the purpose of identifying "out of tolerance" conditions..." This disposition step had a forecasted completion date of November 8, 1992. The inspector noted that this revision had not been incorporated as of the end of this inspection report period. The inspector also noted

that Unit 2 Cycle VII calibration checks had been done using the old acceptance criteria, while the new acceptance criteria was available and validated for use. The inspector was concerned that the expected procedure revision was approximately ten months past its forecast completion date, and still not accomplished.

The inspector reviewed S0123-V-5, "Nonconforming Material, Parts, or Components," and noted that step 6.2.3.12.2 stated that "The work group division supervisor shall take timely action on the NCR disposition work activity..." The licensee provided the inspector with a report of active NCRs not closed, dated August 30, 1993, due to awaiting completion of disposition steps. The inspector noted that out of 576 NCRs in this category, 1214 disposition steps were not completed, and 45% of those disposition steps were beyond their projected completion date. The disposition of the RCP speed pulse shaper was included in this report. The inspector was concerned that the disposition of approved actions resulting from NCRs did not seem to be timely, and that the forecast completion dates for these dispositions did not seem to be realistic.

The inspector concluded that the failure to incorporate the new RCP speed pulse shaper acceptance criteria mentioned above was of low safety significance. This was because the old acceptance criteria was more restrictive than the new acceptance criteria. The inspector considered that the generation of an NCR in this instance was a strength. However, the inspector will review portions of the overdue disposition steps mentioned above, for safety significance, as inspector followup item (IFI 50-361/93-26-01).

2) Pressurizer Spray Valve Failures

The inspector noted that 2PV0100B, the pressurizer spray valve for the Unit 2 loop 1B cold leg, failed after being placed in service during Unit 2 startup after the Cycle VII refueling outage. The valve would not close past approximately 21% from the control room. The licensee mechanically isolated the valve and operated with valve 2PV0100A, the parallel pressurizer spray valve, in service. The inspector reviewed the failure history of valve 2PV0100B. The failure history indicated that the valve had failed eight times since 1983. Four of these failures were during plant operations and four of these failures were during maintenance activities. The predominant cause of failure appeared to be problems associated with the actuator load spring. This spring provided motive force to shut the valve, while instrument air pressure provided force to open the valve. The inspector was informed that the licensee planned to conduct a detailed inspection of the load spring of a spare actuator to determine if corrective action could be taken to prevent recurrence of failure of the spray valves due

to problems associated with the load springs. The inspector considered this approach adequate.

3) Reliability Centered Maintenance

Prompted by the above observations, the inspector interviewed the licensee Maintenance Manager concerning implementation of Reliability Centered Maintenance (RCM) at the site. The Maintenance Manager informed the inspector that an evaluation of the majority of plant systems had been completed, and that all systems were projected to be complete by December 1994. This evaluation included identifying critical components in these systems and identifying failure mechanisms of these components. Industry experience, vendor information, and site experience was then used to evaluate preventive maintenance performed on these components. The manager informed the inspector that failures of plant equipment were evaluated by the Nuclear Plant Reliability Program, the Root Cause Program, and the Nonconformance Report Program. These were the three principal methods that would trigger an evaluation of maintenance activities on a particular component if these maintenance activities could influence failure rate of the component. The RCM program, even upon full implementation, did not strictly incorporate feedback of component failure into the maintenance process. The inspector noted that one of these methods that would trigger an evaluation of maintenance was used in an example mentioned above and considered this a strength. The licensee planned further evaluation of the load spring in the pressurizer spray valve actuator. The inspector considered this action appropriate, and will continue to verify proper corrective action as a result of component failure.

h. Fire Protection Program Inspection (64704)

The inspector reviewed portions of the licensee Fire Protection Program. The inspector used P&ID 40183A and various licensee procedures in the area of fire protection during the review. The inspector noted that the licensee had a fire department that provided the site with seven state certified fire fighters on 24 hour shifts. The inspector considered this a strength. The inspector did note the following minor concerns:

- The inspector identified four root isolation valves located adjacent to the jockey pumps of the fire protection system that had excessive rust. The licensee agreed to perform maintenance to correct the problem.

- The inspector identified that SO23-15-61.A, Revision 0, "Annunciator Response Procedure," listed the setpoint for low-level in the fire diesel fuel tank as "midtank." The inspector was concerned that operators attempting to verify that the annunciator was valid, could not use "midtank" as sufficiently

exact to verify proper alarm initiation. The licensee agreed to evaluate inserting the exact setpoint for this annunciation, instead of using "midtank."

- The inspector interviewed one of the shift brigade leaders. The brigade leader stated that he was not familiar with equipment necessary for safe shutdown of the Unit. The inspector did note that the common operator, by procedure, was responsible for reporting to the scene of a fire and acting as an Operations liaison to the fire department. However, the inspector was concerned that the members of the department, specifically the brigade leaders, had not received specialized training in equipment necessary for safe shutdown. The inspector noted, however, that 10 CFR Part 50, Appendix R, which included the requirement that the brigade leaders receive this training, did not apply in its entirety to the licensee. The inspector and the licensee were reviewing the licensing basis for Fire Protection to determine the requirement, if any, in this area. This will be reviewed as inspector followup item (IFI 50-361/93-26-02).

The inspector concluded that those portions of the licensee's fire protection program inspected were adequate.

No violations or deviations were identified.

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

a. (Closed) Followup Item (50-361/93-11-07), "Potential Enforcement Discretion For Inadequate Boron Concentration."

This item concerned an event on June 9, 1993, involving the potential insufficient boration of the RCS prior to entry into Mode 6. The licensee indicated that it would perform a division investigation to determine the root cause of the event.

The inspector reviewed the licensee evaluation of this event and their proposed corrective actions, as documented in Operations Division Experience Report (ODER 2-93-16). The licensee concluded that the root cause of the problem involved insufficient guidance in the licensee procedures for entry into Mode 6. In particular, the possibility of incomplete mixing, or drawing a steam bubble in the top of the steam generator U-tubes, was not previously recognized and, therefore, appropriate instructions to ensure requisite RCS boron concentration prior to securing the last RCP were not included in the procedure. As a corrective action, the licensee committed to revise the station operating procedures for Mode 5/6 entry to ensure that all RCS parameters which are dependent on forced circulation, including boron concentration, are properly established and verified prior to securing the last RCP. These changes are scheduled for completion prior to the next scheduled Mode 6 entry. The inspector

considered the licensee's actions were adequate. This item is closed.

b. (Closed) Followup Item (50-361/93-02-04), "Jumper not Documented on Form 335."

This item involved the use of Form 335 to control a jumper installed in a control room annunciator. The jumper was controlled with an NCR. However, procedure SO123-II-15.3, "Preparation, Review, Approval and Distribution of the Temporary System Alteration and Restoration Form SO(123) 335," required the use of Form 335 to control all jumpers. Form 335 was not used to control the jumper for the annunciator because the maintenance activity was controlled under more than one MO. Form 335 is not practical to be used when the jumper was installed under one MO and removed under a separate MO, because the form would not be maintained with the MO that would be used to remove the jumper.

The licensee committed to revise procedure SO123-II-15.3 to more clearly communicate the intended application of Form 335 when lifted leads or installed jumpers were used for maintenance activities. The inspector noted that this commitment was incorporated in the licensee Regulatory Commitment Tracking System (RCTS) as committment number 930515. The inspector considered that, based on the incorporation of the commitment into the RCTS, the procedure would be revised. This item is closed.

c. (Closed) Followup Item (50-361/92-24-01). "Incorporation of Harsh Containment Values Into the Emergency Operating Instructions".

This item involved incorporating instrument inaccuracies, under adverse containment conditions, into the emergency operating instructions (EOIs). The Combustion Engineering (CE) Owners Group guidance for EOIs, CEN-152, stated that these values for instrument inaccuracies should be considered in the EOIs.

The inspector noted that a meeting was held between the licensee and NRC technical staff of the Office of Nuclear Reactor Regulation (NRR) on August 5, 1993, at NRC Headquarters, Rockville, Maryland. The licensee presented an implementation plan for incorporation of harsh containment values into the EOIs to the NRR technical staff present. This plan evaluated the EOIs for those steps that would require the operator to make a decision based on instrument readings. These steps would then be evaluated for the effects that harsh containment conditions would have on the instrument readings and associated decisions. The harsh containment condition inaccuracies in the instrument readings would then be incorporated into the EOIs for the step identified. The NRR staff present considered this approach to be adequate. Based on the conclusions of the NRR staff, the inspector had no further concerns in this area. This item is closed.

9. Followup On Items Of Noncompliance (92702)

a. (Closed) Violation (50-361/92-26-03), "Licensee Organization - Personnel Qualification Program."

This violation was the result of inadequate corrective actions taken to correct deficiencies associated with the licensee's Personnel Records Qualification Program. The licensee's QA organization performed an audit of the program in 1991 and issued a corrective action request (CAR) because they found that several qualification resumes were not up-to-date and that several positions had not been included in the program as they should have been. Corrective actions were proposed by the responsible organization and accepted as adequate by QA. In 1992 (a year later), the resident inspector performed an audit of the program and identified similar deficiencies.

In a December 21, 1992, Reply to a Notice of Violation, the licensee indicated that corrective actions included the performance of an audit of other CARs to identify if any had been closed prematurely and the implementation of a new Personnel Qualification Program.

The inspector reviewed QA audits SOS-362-92 and SOS-257-93 and verified that none of the CARs reviewed had been closed before all corrective actions had been completed. However, the inspector noted that audit 362-92 had identified that improvement was warranted with respect to administration and documentation of corrective actions. The inspector reviewed corrective actions taken to address this deficiency, including the addition of more supervisory oversight in the administration and documentation of corrective actions. Additionally, a step was added to QA Procedure N16.03, "Control Issuance and Closure of Corrective Actions Requests," to require a review by a supervisory committee prior to corrective action report closure.

The inspector reviewed SO123-XV-33, "Personnel Qualification Program for the San Onofre Operating Organization," and noted that the procedure included various checks throughout the hiring, transfer, and promotion process to insure that personnel qualifications would be evaluated. The inspector also interviewed personnel responsible for the program and found they were very knowledgeable.

The inspector considered the licensee's actions were adequate. This item is closed.

10. Exit Meeting

On August 27 and September 1, 1993, exit meetings were 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.

EMPLOYEE CONCERNS PROGRAM

PLANT NAME: San Onofre LICENSEE: Southern California Edison (SCE)
DOCKET #: 50-206,361,362

NOTE: Please circle yes or no if applicable and add comments in the space provided.

A. PROGRAM:

1. Does the licensee have an employee concerns program?

   Yes The program is controlled by a Nuclear Engineering, Safety & Licensing Department procedure, NES&L 39-2-1, "Nuclear Safety Concerns" (NSC).

2. Has NRC inspected the program?

   Yes Although a formal evaluation of the program has not been conducted, several reviews of NSC files have occurred during allegation inspection activities. However, these reviews were not formally documented to protect the identity of allegers.

B. SCOPE: (Circle all that apply)

1. Is it for:

   a. Technical? Yes

   b. Administrative? Yes

   c. Personnel issues? Yes

   However, issues related to other programs (i.e., an equal employment opportunity concern) are forwarded to the responsible organization.

2. Does it cover safety as well as non-safety issues?

   Yes The NSC program does not differentiate between safety-related and nonsafety-related components. Concerns are investigated in the same manner regardless of the safety class of components.

3. Is it designed for:

   a. Nuclear safety? Yes

   b. Personal safety? Yes

c. Personnel issues - including union grievances?

Yes However, there are special groups within the licensee's nuclear organization to handle grievances.

4. Does the program apply to all licensee employees? Yes

5. Contractors?

Yes The program applies to anyone that has anything to do with the Nuclear Organization, including offsite entities that support Nuclear (i.e., Shop Support Instrumentation Division, Environmental Engineering).

6. Does the licensee require its contractors and their subs to have a similar program?

No However, the licensee's main contractor, Bechtel, does have a employee concerns program.

7. Does the licensee conduct an exit interview upon terminating employees asking if they have any safety concerns?

Yes When employees terminate employment at SONGS they are normally (not 100% of the time) given a nuclear safety concern form.

C. INDEPENDENCE:

1. What is the title of the person in charge?

Nuclear Oversight Division Manager.

2. Who do they report to?

The Nuclear Oversight Division Manager reports directly to the Vice President, Engineering/Technical Services.

3. Are they independent of line management?

Yes The Vice President, Engineering/Technical Services reports to the Senior Vice President, Power Systems.

4. Does the ECP use third party consultants?

No

5. How is a concern about a manager or vice president followed up?

If a concern challenged the integrity or objectivity of the NSC program, the licensee would go to an agency outside the Nuclear Organization (i.e., Southern California Edison Corporate Security). If a concern pertained to a Vice President, NSC would go to a different Corporate Vice President.

D. RESOURCES:

1. What is the size of staff devoted to this program?

One full time NSC program coordinator. In addition, the coordinator's supervisor acts as a backup and provides oversight as needed.

2. What are ECP staff qualifications (technical training, interviewing training, investigator training, other)?

There are no procedure standards with respect to qualifications for NSC staff.

However, the present coordinator (for the past five years) received a bachelor's degree in Criminal Justice and a master's degree in Human Behavior. The coordinator had a law enforcement background, and was experienced in the area of law enforcement investigations. Additionally, the coordinator had received training in plant systems and various site programs.

E. REFERRALS:

1. Who has followup on concerns

NSC staff, and/or line management.

F. CONFIDENTIALITY:

1. Are the reports confidential?

Yes Reports are kept in a locked file cabinet, and the keys are controlled by two individuals.

2. Who is the identity of the alleger made known to (senior management, ECP staff, line management, other)?

The alleger's identity is only known to the NSC staff, and is specifically not made known to senior management or line management unless the alleger requests or approves it. If the State of California or the NRC subpoenas the alleger's identity, the NSC staff will make the information known.

3. Can employees be:

a. Anonymous?

Yes The concern is handled the same was as if the alleger's name is known. However, the resolution of the concern maintained in a letter to file.

b. Report by phone? Yes

G. FEEDBACK:

1. Is feedback given to the alleger upon completion of the followup?

Yes Feedback is given in the manner the alleger requests it. The licensee makes an effort to resolve the concern to the alleger's satisfaction. Usually, a written summary is provided to the alleger. The resolution of the concern is also discussed with the alleger in person, if possible, or by phone.

2. Does program reward good ideas?

No There other site programs that reward good ideas (i.e., Site Improvement Program).

3. Who, or at what level, makes the final decision of resolution?

The Nuclear Oversight Division Manager. The NOD manager also solicits feedback from the alleger on the NSC program findings.

4. Are the resolutions of anonymous concerns disseminated?

Yes If corrective actions result from the concern, letters are sent to division managers with notification of actions to take.

5. Are resolutions of valid concerns publicized (newsletter, bulletin board, all hands meeting, other)?

No

H. EFFECTIVENESS:

1. How does the licensee measure the effectiveness of the program?

Submittals to the program are trended to identify problems areas

within the Nuclear Organization. Once per year an informal report is prepared to assess the "State of the Program." The inspector reviewed the last report and noted it contained: the number of submissions received within the past year, comparison with the previous year's number of submittals, the number of concerns open at the end of the year, identification of groups from which a large number or percentage of submittals were received, and submittals that received NRC review or were awaiting NRC review.

2. Are concerns:

   a. Trended? **Yes**

   b. Used? **Yes**

3. In the last three years how many concerns were raised? 38 Closed? 36 What percentage were substantiated? 26%

4. How are followup techniques used to measure effectiveness?

   None used.

5. How frequently are internal audits of the ECP conducted and by whom?

   The program is not audited at this time. The licensee was considering the need to perform audits and had drafted a procedure to perform audits.

I. ADMINISTRATION/TRAINING:

1. Is ECP prescribed by a procedure? **Yes**

2. How are employees, as well as contractors, made aware of this program?

   Initial employee training, periodic newsletters, bulletin board postings in various locations around the site, and during termination employees are provided a form to submit any nuclear safety concerns they may have.

ADDITIONAL COMMENTS: **(Including characteristics which make the program especially effective, if any.)**

None

NAME: TITLE: PHONE #:
David L. Solorio/Resident Inspector/714-492-2641 DATE COMPLETED: August 31, 1993
G:PS2\SONGS\MISCDOCS\SO_ECP.TI