ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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License Nos.:	NPF-10 NPF-15
Report No.:	50-361/96-18 50-362/96-18
Licensee:	Southern California Edison Co.
Facility:	San Onofre Nuclear Generating Station, Units 2 and 3
Location:	5000 S. Pacific Coast Hwy. San Clemente, California
Dates:	December 1, 1996 through January 11, 1997
Inspectors:	J. A. Sloan, Senior Resident Inspector J. G. Kramer, Resident Inspector J. J. Russell, Resident Inspector D. G. Acker, Senior Project Inspector D. Desaulniers, NRR Human Factors Specialist G. Good, Emergency Preparedness Analyst T. McKernon, Reactor Engineer R. Lantz, Reactor Engineer
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Attachment:	Supplemental Information

EXECUTIVE SUMMARY

San Onofre Nuclear Generating Station, Units 2 and 3
NRC Inspection Report 50-361/96-18, 50-362/96-18

This routine announced inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of regional inspections of sustained control room observations and emergency preparedness capabilities, and an NRR assessment of corrective actions stemming from a 1995 operational event.

Operations

- The licensee discovered two isolation valves out of position, which occurred as a result of personnel error during recovery from the previous refueling outage. The unit was operated for approximately 1½ years in that condition, contrary to ASME code requirements. The probability of a loss of coolant accident (LOCA) was slightly increased, although no increase in leakage resulted. This was a noncited violation of 10 CFR 50.55a (Section O1.2).

- The licensee's corrective action plan for the April 1995 flow diversion event appeared comprehensive, and corrective actions were adequately implemented and effective. The program for monitoring and reinforcing adherence to the good operating practices defined in Procedure SO23-0-44, "Professional Operator Development and Evaluation Program," contributed substantially to implementation of the corrective actions (Section O1.3).

- Command and control of ongoing outage activities during sustained control room observations was good. Communications were effective but methods were not consistent. Individual operator awareness of ongoing activities was weak at times and stronger feedback could have been provided to the operators regarding completion of, or irregularities resulting from, in-plant activities. Crew briefings and prebriefings for planned testing were good. Control room access was positively controlled, and the shift superintendent provided extensive oversight of control room activities (Section O1.4).

Maintenance

- Licensee control over contract welders, performing welding on the main turbine, initially was not comprehensive, and the welders did not strictly implement the specified parameters for the weld. Licensee corrective actions were thorough and effective (Section M1.3).

- A noncited violation occurred as a result of personnel error. A control element assembly (CEA), which had not been fully grappled, in the spent fuel pool was moved while out of the cage with the cage above water, instead of with the CEA withdrawn into the cage as require by procedure. At least three individuals had the opportunity to stop the event. Communications were weak in that the shift superintendent was not notified of the event in a direct, timely manner (Section M4.1).

Report Details

Summary of Plant Status

Unit 2 began this inspection period in Mode 5, beginning the Cycle 9 refueling outage. Mode 6 was entered on December 8, 1996, and the defueling was completed on December 16. Mode 6 was reentered on January 8, 1997, when fuel was loaded into the reactor. At the end of this inspection period the unit was in Mode 6, and had completed 42 days of the refueling outage.

Unit 3 began this inspection period operating at essentially full power (99 percent), and operated at essentially full power throughout this inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Operations during this inspection were characterized by conservative decision making and careful control of operational and outage activities.

O1.2 Pressurizer Spray Line Drain Valves Found Open - Unit 2

a. Inspection Scope (71707)

On November 30, 1996, after the unit had been shut down for the refueling outage, licensed operators were hanging a clearance on the Unit 2 spray line and identified that two pressurizer spray line drain valves in series on one drain line, Valves S21201MU984 and S21201MU985, were approximately 85 percent open. The drain valves were required to be shut with the reactor in Modes 1 through 3. However, the valves had been open throughout the previous fuel cycle. The licensee notified the inspectors. The inspectors interviewed operators and Operations management, reviewed the normal system alignment that initially recorded these valves as shut (Procedure SO23-3-1.4, Revision 15, Attachment 1, "RCS Pre-Fill Valve Alignment," performed March 20, 1995) and a subsequent Work Authorization Record (WAR 2-9501138) that had recorded these valves as opened and then shut in order to work on the pressurizer spray valve. The inspectors also reviewed Piping and Instrumentation Drawing 40111D, Revision 5, "Reactor Coolant System (RCS)," and reviewed Action Request (AR) 961101395, which the licensee generated as a result of the finding.

b. Observations and Findings

The Kerotest globe valves were located in series in order to isolate a 1-inch vent pipe off of the 4-inch pressurizer spray line inside containment. Downstream of the valves was a T-joint to another pressurizer drain line and a blank flange. Operating with the valves open provided reactor coolant pressure and temperature up to the blank flange; normally the piping is depressurized. The valves were recorded as

shut during the system alignment performed during the refueling outage, and were recorded as opened and shut (independently verified) on May 13, 1995, in order to work on Spray Valve 2PV0100A. The licensee was unable to establish when the valves had been opened, and in the AR postulated that either the valves had vibrated open during power operations, had not been shut as the WAR indicated, or had been reopened after the WAR. The inspectors concluded that the valves vibrating open was not credible, because the line had no indication of excessive vibration. The valves were located on a drain line not immediately adjacent to the spray line such that spray line vibration would have had to have been of a high magnitude to cause such excessive vibration in the drain valves. In addition, similar Kerotest isolation valves off the spray line were not open. There was no history of vent or drain valves changing position due to vibration, and no generic instances of Kerotest valves changing position in this manner. Consequently, the inspectors concluded that human error, most probably, caused the mispositioning either at the time of the WAR closure with the reactor in Mode 4, or at a later date as work activities in the area continued.

Operation of the unit at power with these valves open was contrary to the description of the RCS in the Updated Final Safety Analysis Report (UFSAR) (Section 3.2, the Q list), which indicated that all RCS pressure retaining piping was ASME Class 1. The second isolation Valve, 2MU985, provided an ASME Code break between Class 1 and Class 3 piping. It also provided a break between Seismic Class 1 and Class 2 piping. A break in the piping (approximately 57 feet) downstream of the second isolation valve and upstream of the blank flange, or a break in the blank flange, could have resulted in a LOCA. The probability of a LOCA had been slightly increased, since there was more piping, and the additional piping was not constructed to the ASME Code or the seismic qualification stipulated in the UFSAR.

Licensee corrective actions included training all operators in verifying valve position using at least two indications, installing locking devices on these valves, and including them in the locked valve program. The inspectors found that operating Unit 2 for approximately 1½ years with these valves open was a violation of 10 CFR 50.55a, Section C, which states that the reactor coolant pressure boundary must meet the requirements for ASME Code Class I components. Contrary to this, the approximately 57 feet of piping, and the blank flange, did not meet the requirements for Class I components. Although the probability of a LOCA increased, the piping was rated for RCS pressure and temperature, constructed to Class 3 standards, and did not cause increased leakage from the RCS. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-361/96018-01).

c. Conclusions

The licensee discovered two isolation valves out of position, which had occurred during recovery from the previous refueling outage. The unit was operated for approximately 1½ years in the condition, with the probability of a LOCA slightly increased, although no increase in leakage resulted. This was a noncited violation of the ASME Code and, consequently, 10 CFR 50.55a.

O1.3 Command and Control Corrective Actions

a. Inspection Scope (92901)

On April 6, 1995, licensed operators inadvertently transferred 560 gallons of RCS inventory from the Unit 2 RCS to the refueling water storage tank. The event revealed problems in the area of control room command and control. The licensee subsequently committed to conduct an evaluation and implement the changes deemed appropriate. In July 1995, the licensee issued Safety Engineering Report SEA 95-05, "Command and Control Evaluation." The report included recommendations for corrective actions in the following six areas: lines of authority, performance expectations, formality, fundamentals, communications, and coordination. The inspectors verified the implementation and evaluated the effectiveness of corrective actions taken in each of these areas.

b. Observations and Findings

Lines of Authority - The licensee had revised Procedure SO123-0-30, "Shift Manning," Revision 1, to adequately specify the chain of command for outage periods and power operations. Interviews with licensed operators and plant technical staff indicated that those individuals understood the chain of command and coordinated work activities with the control room in accordance with the specified chain of command.

Performance Expectations - Written expectations had been established for each watch station. Procedure SO23-0-44, "Professional Operator Development and Evaluation Program," Revision 2, detailed "good operating practices" and supervisory skills in the areas of verbal communications, procedures use, annunciator response, problem solving, plant monitoring, plant manipulation, and tailboarding. The procedure also provided guidance for the periodic evaluation of adherence to the good operating practices and identified "observable standards" to aid these evaluations. The periodic evaluations had been performed at the recommended frequencies. The licensee also had developed a pocket reference, "Watchstation Expectations, Units 2 and 3 Operations." Observations concerning operator compliance with the good operating practices are discussed in Section O1.4.

Formality - Licensee corrective actions in this area included efforts to "establish additional screening of personnel entering the control room by informing all site personnel of the correct contact for the type of activity involved" and to "communicate management expectations on annunciator response." Site personnel were informed of the appropriate operations personnel to contact, so as to minimize unnecessary calls to the control room, by a memorandum from R. W. Krieger, dated July 18, 1995. As noted previously, management expectations for annunciator response were addressed in Procedure SO23-0-44. Observations concerning operator performance in the area of maintaining formal conduct in the control room and annunciator response are discussed in Section O1.4.

Fundamentals - Licensee corrective actions in the area of fundamentals included providing operators with supplementary training in problem solving and incorporating, in requalification training, core competencies that support problem solving. The Operations Training supervisor stated during an interview that the most recent licensed operator requalification training cycle included training on reading electrical elementary prints followed by a 1/2-day simulation exercise of problem solving skills using elementary prints. A 1-day training session was also provided in pump fundamentals. Interviews with licensed operators indicated that these training sessions were perceived as valuable in clarifying and reinforcing fundamental concepts and skills in these areas.

Communications - The licensee's corrective action in the area of communications was to require a single communications practice for all operations; i.e., normal and abnormal, in the control room, simulator, and plant. Management expectations for communications were adequately described in Procedure SO23-0-44 and in the licensee's "Watchstation Expectations, Units 2 and 3 Operations" pamphlet. Interviews with operators and training personnel indicated that they perceived a significant improvement in the formality of communications since July 1995. During sustained control room observations, operator communications appeared to be adequate, although occasional lapses were observed in maintaining 2- and 3-way communications.

c. Conclusions

The licensee's corrective action plan was comprehensive and the corrective actions had been adequately implemented and effective. The program for monitoring and reinforcing adherence to the good operating practices defined in Procedure SO23-0-44 substantially contributed to implementation of the corrective actions.

O1.4 Conduct of Operations - Extended Control Room Observations

a. Inspection Scope (71715)

During the period of December 16-20, 1996, independent observations of control room activities were conducted with a focus on the Unit 2 outage activities. The objective of the observations was to evaluate control room performance by the operators, crew command and control, communication practices, work control process control, and procedure usage. The inspectors observed a number of outage management meetings, control room shift briefings, prejob briefings, shift turnover briefings, annunciator acknowledgments and responses, surveillance tests, and conducted interviews with selected key personnel.

b. Observations and Findings

Detailed prebriefings were conducted for witnessed tests such as the safety injection Train B miniflow check valve leakage tests and "motor-operated valve analysis and test system" testing of safety injection miniflow isolation Valves 2HV9347 and 2HV9348. Test group members and operating crew members were briefed on key test evolutions, test controls, critical parameters to monitor, and past experience and lessons learned with performing the operation or test. In most instances, testing was coordinated through a test engineer stationed in the control room. However, in one instance, the operators appeared unaware of an anticipated annunciator alarm due to containment radiation monitor circuitry testing being conducted on the back panels. In other instances, not all operating crew members appeared cognizant of work activities which affected annunciator alarms, such as vital DC trouble alarms and instrument failure alarms on the common alarm panel.

The operators practiced good cross-checking for activities being conducted within the control room, such as load testing of Emergency Diesel Generator (EDG) 2G003. However, for some inplant testing in which the technician in the plant was designated as controlling the evolution, such as the containment airborne radiation isolation valve local leakrate test, cross-checking was less effective. In this case the control room operator did not have a test procedure in hand and was, therefore, unable to positively verify which step of the procedure had been completed or whether it was completed accurately. Procedure SO23-0-44 defined cross-checking to include reference to the guiding procedure to verify correct component manipulation.

Communications were effective but methods were not consistent. The communications used by the operators varied between 2-way/3-way to informal acknowledgments of annunciators. Communication practices varied between

operating crews and individuals in the crews. In other instances, sharing of information between crews and among crew members appeared lacking. This was exemplified during control room discussions of activities related to steam generator chemical cleaning emphasized the use of toxic chemicals and the forewarning of potentially hot piping during high velocity rinsing. However, the same information did not appear to be conveyed to the plant equipment operators during the shift briefing.

In other instances, the inspectors observed that the control room operators were not aware of the reason for some annunciated alarm tiles. For example, the operators were not aware of a lit containment/fuel handling building temperature high alarm tile and believed, at first, it was due to ongoing work. However, in the subsequent investigation the operators found that the tile was lit due to a failed recorder relay. The tile was tagged with an annunciator compensatory action sticker which reminded the operators to use a redundant instrument to monitor the parameter. The inspectors did not consider this issue as having high safety consequence since a number of redundant indications and alarms existed to alert operators of conditions in the fuel handling building. Followup discussions with the operators indicated that not all individual annunciators were tracked during an outage. However, annunciators for which links had been disconnected in the back panels, annunciators for which ongoing testing was being conducted, ones which required monitoring of redundant instrumentation indications, and annunciators for which a setpoint had been compensated were logged and tracked by the operators.

c. Conclusions

The command and control of ongoing activities was good. Communications were effective but methods were not consistent. Individual operator awareness of ongoing activities was weak at times and feedback of completion of, or irregularities resulting from, inplant activities to the operators could have been stronger. Crew briefings and prebriefings for planned testing were good.

The inspectors observed good command and control within the control room and by the shift superintendents and the Units 2 and 3 control room supervisors. Control room access was formally controlled and restricted to onshift operators, operations managers, and individuals coordinating outage testing. The shift superintendent spent greater than fifty percent of his time overseeing control room activities and coordinating with the units' control room supervisors.

O8 Miscellaneous Operations Issues (71707)

O8.1 Technical Specification (TS) Interpretations

The inspectors conducted a survey of the licensee's TS Clarifications Manual and determined that the following TS Clarifications contained informal references to NRC review and/or approval without formal NRC documentation:

10	129 (Revision 1)	136
14	130 (Revision 1)	146
49 (Revision 1)	135 (Revision 1)	148

The inspectors informed the licensee that this form of NRC involvement in TS interpretations is not recognized by the Commission and is not an acceptable practice. The inspectors requested that the licensee remove any informal references to NRC review and/or approval from the TS interpretations. The Compliance manager stated that all these TS Clarifications would be either deleted or incorporated into the TS bases over the next few months, and that all such references to informal NRC concurrence would be removed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

The inspectors observed all or portions of the following work activities:

- reactor coolant pump Motor M003 oil and bearing maintenance - Unit 2
- EDG 2G002 refueling interval maintenance - Unit 2

b. Observations and Findings

The work performed under these activities was thorough. All work observed was performed with the work package present and in active use. Technicians were knowledgeable and professional. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place.

In addition, see the specific discussion of maintenance observed under Section M1.3, below.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillance activities:

- EDG 2G003 loss of voltage signal start test - Unit 2
- high pressure safety injection Pump 2(3)MP019 and valve testing - Unit 3

b. Observations and Findings

All surveillances performed under these activities to be thorough. All surveillances observed were performed with the work package present and in active use. Technicians were knowledgeable and professional. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place.

In addition, see the specific discussion of surveillances observed under Sections M3.1, below.

M1.3 Main Turbine Welding - Unit 2

a. Inspection Scope (62707, 71500)

On December 19, 1996, the inspectors observed welding activities being performed on Unit 2 low pressure Turbines 1 and 3 in order to install new stainless steel inserts on the carbon steel turbines. The inspectors also reviewed Procedure SO123-V-7.1, Revision 1, "SCE SONGS Welding Program."

b. Observations and Findings

Welding activities on the main turbine were examined. The inspectors considered the maintenance of the main turbines to be important in light of the catastrophic failure of similar turbines at Fermi, the history of cracks previously observed at San Onofre, and the challenge to plant safety that could result from a turbine failure.

Contract welders used Weld Procedure Specification (WPS) P8,1-GTAW, in order to accomplish the welding under Maintenance Order 96120338000. A WPS was required to be used when welding under the ASME code. The main turbine was not required to be constructed or repaired under the ASME code, but the licensee welding organization had decided to use a WPS because these specifications were validated through the use of test welds and, as such, were assured to produce sound welds. Contract welders were being used.

The WPS required, in part, a maximum amperage of 140 amps, a maximum interpass temperature of 350°F, a maximum weld thickness of 1/2 inch, and that the weld to be for P8 to P1 material (P designations were defined in the ASME code and were based on the type of base metal). The inspectors observed that the actual welding used current as high as 150 amps; for portions of the weld where multiple passes were performed, interpass temperature was not measured; the weld thickness was approximately 1/16-inch over the 1/2-inch maximum; in a section where the ring was joined to itself, the weld was P8 to P8. Each of these was not in accordance with the WPS that the welder should have been following. The high interpass temperature, thick weld bead, or high amperage each put more heat into the base metal than was tested in the test weld. This could lead to base metal properties conducive to failure. The filler material used was verified for stainless to carbon steel (P8 to P1), but not stainless to stainless (P8 to P8).

As a result of the inspectors' comments, licensee welding supervision ensured that the welders more closely controlled current and began to measure interpass temperature. The welding engineer stated that they had determined that the filler material for the stainless to stainless would be adequate, and that the overage on bead thickness should have no effect due to the large volume of quench metal.

c. Conclusions

Licensee control over the contract welders initially was not comprehensive, and the welders did not strictly implement the specified parameters for the weld. Licensee corrective actions were thorough and effective.

M3 Maintenance Procedures and Documentation

M3.1 EDG Single Load Reject Test

a. Inspection Scope (61726 and 71707)

The inspectors reviewed the licensee's actions in response to their determination that previously conducted EDG surveillance testing may not have met the current surveillance requirements.

b. Observations and Findings

On January 6, 1997, the licensee determined that the EDGs may not have been tested during the last (1995) refueling outages as required by a new surveillance requirement (implemented in August 1996 as part of Amendment 127) regarding the frequency response following the rejection of a single load. The new Surveillance Requirement, SR 3.8.1.9, included different initial test conditions and a new requirement for the EDG frequency 4 seconds after the load was rejected. The licensee entered SR 3.0.3 for both units, which allowed 24 hours to complete

missed surveillances, thus allowing time to retrieve and review the data or conduct another test satisfying the new requirements.

On January 7, the licensee determined that a test had not been performed demonstrating that EDG 3G002 met the current requirement, and that testing in Mode 1 was unwise. The EDG was declared inoperable. The other EDGs were determined to be operable at that time.

In a conference call between the licensee and NRC personnel on January 8, it was established that SR 3.8.1.9 did not require the EDG to be inductively loaded as the licensee had understood. Based on data provided by the licensee during the discussion, the licensee concluded that all the EDGs were currently operable based on the most recent surveillance test data. The licensee then declared EDG 3G002 operable.

During the call, the licensee informed the NRC that EDG 2G002 may not have had a surveillance test demonstrating its capability to meet the 4-second stability criteria of the revised SR, from the time of the revision (August 5, 1996) until the test was performed during the current outage.

Also during the call, NRC and the licensee agreed that the specific requirements in the SR and its basis, as currently worded, were unclear and warranted prompt revision to clarify. The licensee's Vice President, Nuclear Generation, stated that the licensee would send a letter to the NRC explaining how the EDG testing that had been performed satisfied the SR requirements. Additionally, he stated that a TS amendment would be submitted to clarify the SR and its basis.

On January 11, 1997, the licensee informed the inspectors of three additional EDG surveillances for which the tests of record did not meet the current SR. In all cases, the testing actually performed was more restrictive than currently required. A conference call was scheduled to discuss these issues after the end of this inspection period. The inspectors will review these, together with the single load reject surveillance tests of record, as an unresolved item (Unresolved Item 50-361(362)/96018-02).

c. Conclusions

The EDGs all satisfied the requirements of SR 3.8.1.9. The requirements of SR 3.8.1.9 were unclear, warranting prompt correction. The failure to have a documented test demonstrating compliance with SR 3.8.1.9 for EDG 2G002 between August and December 1996, and for three additional EDG surveillances for Unit 3 EDGs, was an unresolved item.

M4 Maintenance Staff Knowledge and Performance

M4.1 CEA Movement with Elevated CEA Cage and Subsequent Cage Drop - Unit 2

a. Inspection Scope (71707)

On December 17, 1996, the licensee's Operations Manager informed the inspectors, via telephone, that a fuel handler heard a splash in the Unit 2 spent fuel pool as a CEA was about to be lowered into a fuel assembly during CEA changeouts at about 11 p.m. on December 16, 1996. In order to assess the causes of the splash and the flow of communications, the inspectors interviewed the Operations Manager and fuel handlers, observed CEA change-outs, inspected a spare CEA handling tool, and reviewed fuel handler qualifications.

b. Observations and Findings

A contract fuel handler and two assigned spotters were changing CEAs in the Unit 2 spent fuel pool using a lightweight CEA tool. The handler failed to completely grapple a CEA he was preparing to lift from a fuel assembly. The CEA did raise from the assembly, but because the grappling handle was not fully turned, the cage that should have surrounded the CEA and remained submerged with the CEA stayed positioned above the CEA. Raising the CEA caused the cage to become partially uncovered by water. The operator then moved the CEA, with the cage above it, to the location above the receiving fuel assembly. Subsequently, the cage dropped down, covered the CEA, and created a splash in the pool. The operator then contacted the refueling supervisor, who responded to the pool and discussed the event with the refueling manager. The refueling manager directed the lowering of the CEA into the assembly, based on the verbal report from the refueling supervisor (1 hour and 20 minutes after the splash). The refueling supervisor then contacted the duty Outage Control Center manager. The Operations liaison in the Outage Control Center building heard the conversation and contacted the shift superintendent. The shift superintendent contacted the Operations Manager, then interviewed the refueling supervisor and stopped CEA movement in the pool.

The shift superintendent was assigned overall responsibility for implementation of abnormal procedures, if any fuel damage were to occur; as such, he should be cognizant of any abnormalities at an early stage. The CEA was lowered without the shift superintendent's consent or knowledge. The inspectors found that the shift superintendent was not notified in a timely, directly manner by spent fuel pool personnel.

The operator, when lifting the CEA with the cage above it, should have noted abnormally high weight, and should have seen the cage out of the water. The spotters should have observed the same things, especially while the CEA was moving. Unit 2 TS 5.5.1.1 states that the procedures recommended in Regulatory

Guide 1.33, Revision 2, Appendix A, shall be implemented. Licensee Procedure SO23-X-7.2, Temporary Change Notice 2-3, "Nuclear Fuel Movement-Spent Fuel Pool," is applicable to Regulatory Guide 1.33. Step 6.1.2 of this procedure stated that the CEA would be grappled and raised into the cage fully before the cage weight is again picked up and the CEA is relocated. Contrary to this, the CEA was moved to a new location while not raised into the cage.

The licensee's investigation and corrective actions were thorough and included inspecting the fuel assembly that the CEA was suspended above when the splash occurred, adjacent fuel assemblies, the CEA, the CEA handling tool, and discussing the incident with the individuals involved. The inspectors reviewed the qualifications of the operator and observed the operator performance during the movement of CEAs on December 17, 1996. No discrepancies were noted. Based on the licensee's thorough investigation and corrective actions, and the low safety significance of the event, this licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VIIB.1 of the NRC Enforcement Policy (NCV 50-361/96018-03).

c. Conclusions

Communications were weak in that the shift superintendent was not notified of the event in a timely, direct manner. A noncited violation was identified because the CEA was moved without being raised fully into the cage, as was procedurally required, despite the fact that at least three individuals had the opportunity to stop the event.

M8 Miscellaneous Maintenance Issues (92902, 92712)

M8.1 (Closed) Inspection Followup Item 50-361, 362/94005-01: inservice testing (IST) of auxiliary feedwater (AFW) pumps. This item was opened for review of calculations the licensee had in progress to ensure that the IST procedure also bounded the safety analysis criteria for AFW flow. The inspectors reviewed the revised licensee calculations and concluded that the IST criteria would bound the safety analysis criteria. The licensee's AFW IST procedure was modified to require that the data reviewer ensure that the data was within the design basis.

M8.2 (Closed) Licensee Event Report (LER) 50-362/96001-01: loss of voltage signal due to inadvertent relay trip. This issue was previously reviewed and closed in NRC Inspection Report 50-361(362)/96002. The supplement to the original LER did not reveal any significant changes, and is closed.

III. Engineering

E2.1 Review of Facility and Equipment Conformance to UFSAR Description (37551)

A recent discovery of a licensee operating its facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable sections of the UFSAR that related to the inspection areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

E8 Miscellaneous Engineering Issues (92700, 92903)

E8.1 (Closed) Violation 50-361/96009-01: failure to declare inverter inoperable. The inspectors reviewed AR 960801065, the LER, and the licensee's response to the Notice of Violation. The licensee determined that the root cause of the violation was that the acceptance criteria had been inappropriately deleted from the surveillance procedure, so that operators and engineers did not recognize any acceptance criteria for the inverter output voltage. The licensee performed a detailed evaluation of the inverter loads and determined that all loads were operable with the inverter output at 122.5-Vac. The licensee restored the acceptance criteria to the surveillance procedure, and initiated actions to expand the criteria consistent with the results of the operability evaluation. The licensee also reviewed other Operations surveillances for deficient acceptance criteria, and identified four procedures requiring revision. The AR also identified and addressed corrective actions for communications weaknesses not identified in the LER. The inspectors concluded that the licensee's completed and proposed corrective actions effectively corrected the violation.

E8.2 (Closed) LER 362/96002-00: pressurizer safety valve (PSV) setpoints out of tolerance. The setpoints for both of the Unit 3 pressurizer PSVs were found to be between 1 and 2 percent high after being removed at the end of Cycle 7. The licensee performed an evaluation of Cycle 7 operation and determined that the UFSAR accident analysis bounded the condition. The licensee determined that the setpoints had been correctly set prior to Cycle 7. No cause for the setpoint drift was identified. The licensee had initiated an evaluation to support expanding the allowable values of the setpoint, based on a similar previous event. That evaluation has not been completed. The setpoints of the valves were reset to within acceptable limits.

In the TS in effect during Cycle 7, TS 3.4.2 required that, in Modes 1-3, all PSVs be operable with a lift setting of 2500 psi ±1 percent. Because the valves had drifted outside the tolerances sometime during the previouw operating cycle, the licensee was not aware of the discrepancy untilthe valves were removed and tested during the refueling outage. The licensee reported this condition, as required, by LER

because the acions required by TS 3.0.3 had not been taken when the valves initially drifted out of specification during the previous operating cycle. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-361/96018-04).

E8.3 (Closed) LER 361/96006-00: vital bus inverter nonconformance with TS SR 3.0.1. This item was discussed in Section E8.1.

IV. Plant Support

P3 Emergency Preparedness Procedures and Documentation

P3.1 Licensee Onshift Dose Assessment Capabilities (Temporary Instruction 2515/134)

a. Inspection Scope

The inspectors conducted an in-office review of the San Onofre Nuclear Generating Station Emergency Plan, Revision 6.1, and Emergency Plan Implementing Procedures SO123-VIII-10, "Emergency Coordinator Duties," Revision 8, and SO123-VIII-40.100, "Dose Assessment," Revision 7, to obtain the information requested by the temporary instruction. The inspectors conducted a telephone interview with the licensee on December 18, 1996, to verify the results of the review.

b. Conclusions

The inspectors determined that the licensee had the capability to perform onshift dose assessments using real-time effluent monitor and meteorological data and that the process was clearly described in the emergency plan and implementing procedures.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the exit meeting on January 14, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

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R. Krieger, Vice President, Nuclear Generation
D. Nunn, Vice President, Engineering and Technical Services
T. Vogt, Plant Superintendent, Units 2 and 3
R. Waldo, Manager, Operations

NRC

M. Fields, NRR Project Manager
E. Tomlinson, NRR Technical Specification Branch

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71500:	Balance of Plant
IP 71707:	Plant Operations
IP 71715:	Sustained Control Room Observations
IP 71750:	Plant Support Activities
IP 92700:	On Site LER Review
IP 92712:	Inoffice Review of LER
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
TI 2515/134:	Licensee Onshift Dose Assessment Capabilities

ITEMS OPENED AND CLOSED

Opened

50-361/96018-02 50-362/96018-02	URI	EDG surveillance tests not performed

Opened and Closed

50-361/96018-01	NCV	RCS pressure boundary valves mispositioned
50-361/96018-03	NCV	CEA handling procedure not followed
50-361/96018-04	NCV	PSV setpoints out of tolerance

Closed

50-361/94005-01 50-362/94005-01	IFI	inservice test of AFW pumps
50-362/96001-01	LER	loss of voltage due to inadvertent relay trip
50-362/96002-00	LER	PSV setpoints out of tolerance
50-361/96006-00	LER	vital bus inverter nonconformance with TS SR 3.0.1
50-361/96009-01	VIO	failure to declare component inoperable

LIST OF ACRONYMS USED

AFW	auxiliary feedwater
AR	action request
CEA	control element assembly
EDG	emergency diesel generator
IST	inservice test
LER	licensee event report
LOCA	loss of coolant accident
NCV	noncited violation
PDR	Public Document Room
PSV	pressurizer safety valve
RCS	reactor coolant system
SR	surveillance requirement
TS	Technical Specification
UFSAR	updated final safety analysis report
WAR	work authorization record
WPS	weld procedure specification