UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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May 30, 2000

Harold B. Ray, Executive Vice President
Southern California Edison Co.
San Onofre Nuclear Generating Station
P.O. Box 128
San Clemente, California 92674-0128

SUBJECT: NRC ROUTINE INSPECTION REPORT NO. 50-361/00-06; 50-362/00-06

Dear Mr. Ray:

This refers to the inspection conducted on April 2 through May 20, 2000, at the San Onofre Nuclear Generating Station, Units 2 and 3, facility. The enclosed report presents the results of this inspection. The results of this inspection were discussed on May 19, 2000, with Mr. R. Krieger and other members of your staff.

The NRC identified four issues that were evaluated under the risk significance determination process and were determined to be of very low safety significance (Green). These issues have been entered into your corrective action program and are discussed in the summary of findings and in the body of the attached inspection report. Of the four issues, three were determined to involve violations of NRC requirements but, because of their very low safety significance, the violations are not cited. If you contest these noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC, 20555-0001, with copies to the Regional Administrator, Region IV; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC, 20555-0001; and the NRC Resident Inspector at the San Onofre facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if any, will be placed in the NRC Public Document Room (PDR).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

***Elmo E. Collins for***

Charles S. Marschall, Chief
Project Branch C
Division of Reactor Projects

Docket Nos.: 50-361
50-362
License Nos.: NPF-10
NPF-15

Enclosures:
NRC Inspection Report No.
50-361/00-06; 50-362/00-06

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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|---|---|
| Docket Nos.: | 50-361<br>50-362 |
| License Nos.: | NPF-10<br>NPF-15 |
| Report No.: | 50-361/00-06<br>50-362/00-06 |
| Licensee: | Southern California Edison Co. |
| Facility: | San Onofre Nuclear Generating Station, Units 2 and 3 |
| Location: | 5000 S. Pacific Coast Hwy.<br>San Clemente, California |
| Dates: | April 2 through May 20, 2000 |
| Inspectors: | J. A. Sloan, Senior Resident Inspector<br>J. G. Kramer, Resident Inspector<br>J. J. Russell, Resident Inspector<br>L. T. Ricketson, Senior Radiation Specialist<br>M. F. Runyan, Senior Reactor Inspector |
| Approved By: | Charles S. Marschall, Chief, Project Branch C |

ATTACHMENTS:

Attachment 1: Supplemental Information

Attachment 2 NRC's Revised Reactor Oversight Program

<u>SUMMARY OF FINDINGS</u>

San Onofre Nuclear Generating Station, Units 2 and 3
NRC Inspection Report No. 50-361/00-06; 50-362/00-06
**April 2 through May 20, 2000**

The report covers a 7-week period of resident inspection and the results of in-office inspections of open items by regional inspectors. The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the significance determination process in Inspection Manual Chapter 0609.

Cornerstone: Initiating Events

- Green. Licensed operators responding to a control element assembly timer failure alarm skipped steps in the procedure for placing a control element assembly on the maintenance hold bus. Although allowed by procedure, this omission, combined with the initial electrical problem, caused the control element assembly to drop, which resulted in a plant transient.

  The issue was characterized as a “green” finding using the significance determination process. This issue was determined to be of very low significance because mitigation equipment was not affected (Section 1R14).

Cornerstone: Mitigating Systems

- Green. The licensee determined that one Unit 2 Train A saltwater cooling pump discharge isolation valve was inoperable since November 1998 as the result of the recognition that leakage from emergency air accumulators could result in the valve not remaining in its safety position following a loss of instrument air. Although the redundant pump and valve in Train A were generally available, they were not aligned for automatic operation. Consequently, Train A was inoperable for extended periods while the affected pump and valve were aligned for service. This was a noncited violation of Technical Specification 3.7.8 and was is in the licensee’s corrective action program as Action Requests 000401454 and 000500354. All of the saltwater cooling pump discharge valves, and the component cooling water return isolation valves from shutdown cooling heat exchangers, in both units, were incrementally found to be inoperable before more rigorous analysis showed only one valve had been inoperable. The inspectors identified a significant error in the licensee’s initial operability assessment that resulted in all Train A saltwater cooling pump discharge isolation valves being considered inoperable before the final evaluation was completed.

  The issue was characterized as a “green” finding using the significance determination process. The inspectors agreed with the licensee's determination that both trains of saltwater cooling were functional, although manual operator actions were required to align redundant equipment. Phase 3 of the significance determination process, performed by a Senior Reactor Analyst in conjunction with the licensee, accounted for both internal and external events which, in part, may result in the loss of instrument air, concluded that the issue was of very low significance (Section 1R15.3).

- Green. The licensee failed to follow its procedure for scaffolding erection, in that the inspectors identified multiple examples of inadequate standoff distances between the scaffolding and safety-related components of the safety injection and shutdown cooling systems in both units. This was a noncited violation of Technical Specification 5.5.1.1.a, which requires that procedures be followed. The licensee's initial corrective actions were prompt but not thorough. The licensee subsequently identified additional examples of inadequate standoff distances in scaffolding around other safety systems, indicating that the problem was programmatic. The violation was in the licensee's corrective action program as Action Requests 000401202 and 000401588.

  The issue was characterized as a "green" finding using the significance determination process. No components were rendered inoperable; therefore, the issue was determined to be of very low significance (Section 1R13.1).

- Green. The inspectors identified that licensee design engineers failed to correctly translate the design basis required minimum saltwater cooling flow into operability curves used by Station Technical engineers. This was a noncited violation of 10 CFR Part 50, Appendix B, Criterion III. The violation is in the licensee's corrective action program as Action Request 000400107.

  The issue was characterized as a "green" finding using the significance determination process. The operability curves were nonconservative; however, they did not result in any incorrect saltwater cooling operability assessments during the last 2 years; consequently, this issue was determined to be of very low significance (Section 1R15.2).

## Report Details

Summary of Plant Status:

Unit 2 operated at essentially 100 percent power throughout this inspection period. Unit 3 operated at essentially 100 percent power throughout this inspection period, except for April 7, 2000, following a dropped control element assembly (CEA).

1. **REACTOR SAFETY**
Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness

1R04 Equipment Alignments

a. Inspection Scope

The inspectors performed equipment alignment verifications for portions of the following systems:

- Component cooling water (CCW) Train B (Unit 3)
- Auxiliary Feedwater Train B (Unit 2)

b. Issues and Findings

There were no findings identified during this inspection.

1R05 Fire Protection

a. Inspection Scope

The inspectors performed fire protection walkdowns of the following areas:

- Emergency diesel generator building (Unit 2)
- Saltwater cooling (SWC) pump room and tunnel (Unit 3)
- Cable spreading tunnels (Unit 3)

b. Issues and Findings

There were no findings identified during this inspection.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors performed flood protection walkdowns to assess barriers, systems, and other features that provide for the protection from flooding of the Unit 2 emergency core cooling system (ECCS) in the safety equipment building.

b. Issues and Findings

There were no findings identified during this inspection.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed the implementation of the Maintenance Rule for the following:

- Instrument air system (Units 2 and 3)
- Main feedwater system (Units 2 and 3)

b. Issues and Findings

There were no findings identified during this inspection.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

.1 Scaffolding Near ECCS - Units 2 and 3

a. Inspection Scope

On April 21, 2000, the inspectors observed the emergent work associated with installing insulation on ECCS piping in the Train A ECCS pump rooms in Units 2 and 3.

b. Issues and Findings

Inspectors had determined (in NRC Inspection Report 50-361; 361/00-03) that the licensee's heat loading calculations for the ECCS pump rooms incorrectly assumed that the ECCS piping was insulated, but the piping was not insulated. The licensee promptly initiated installing insulation, in parallel with verifying the operability of the cooling equipment and the ECCS trains. This work activity involved erecting extensive scaffolding around the piping and other ECCS components. The inspectors identified numerous discrepancies with the scaffolding.

On April 21, 2000, the inspectors determined that the scaffolding was not erected to the requirements established in Procedure SO123-I-1.34, "Scaffolding Erection," Temporary Change Notice 6-1. For scaffolding in high seismic areas, Section 6.4.3.2 states that "a clearance of at least 1 inch shall exist between Important to Safety equipment and any scaffold parts" except as waived based on prior engineering evaluation. Contrary to this, the inspectors identified five locations in Unit 2 and three locations in Unit 3 where the scaffolding was within 1 inch of safety injection system or shutdown cooling system piping and other components. The smallest standoff distance was approximately 1/4 inch between a plywood scaffolding platform and the Unit 2 high pressure safety injection Pump 2P017 minimum flow recirculation piping. Additionally, the inspectors identified two 12-inch wrenches in the area above high pressure safety injection Pump 3P017 in Unit 3.

The licensee promptly initiated corrective actions, as documented in Action Request (AR) 000401202. The documented corrective actions were to completely inspect the scaffolding, adjusting as necessary to provide margin to the 1-inch procedural requirement, and then independently reinspect to ensure compliance. The inspections and corrective actions were documented in Maintenance Orders 00041203 and 00041204. Additionally, the licensee performed an operability assessment (on the as-left condition) and a reportability assessment, which included an operability assessment of the as-found condition.

The inspectors reviewed the operability assessment of the as-found condition, which concluded that a 3/8-inch standoff distance was acceptable. The inspectors noted that the licensee's list of as-found conditions did not include the 1/4-inch standoff distance that had been observed in Unit 2. Also, on April 29, during a plant status walkdown, the inspectors observed that two of the previously-identified discrepancies in Unit 3 had not been corrected as the inspectors had been informed. In response, the licensee reperformed the walkdown of the remaining discrepancies with the inspectors, corrected the discrepancies, and initiated Apparent Cause Evaluation 000401202 to determine why the discrepancies had not been properly identified and corrected. Additionally, the licensee reperformed the operability assessments of the as-found and as-left conditions and determined that the as-found conditions did not render the systems inoperable. The licensee also inspected several other scaffolds near safety-related components and identified numerous other similar discrepancies, for which the licensee was considering programmatic changes.

The inspectors determined that the scaffolding configuration, which had been in place for approximately 2 days before the initial problem was identified, could potentially affect the seismic response of the ECCS and CCW systems, although the likelihood of these systems being damaged as a result of the scaffolding was low. Using the Significance Determination Process (SDP), the inspectors determined that the issue was of very low risk significance because the equipment remained operable (Green).

Technical Specification 5.5.1.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33 recommends procedures for performing maintenance that can affect the performance of safety-related equipment. Contrary to this, the licensee failed to fully implement Procedure SO123-I-1.34, as described above. This violation of Technical Specification 5.5.1.1.a is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 361; 362/2000006-01). This violation is in the licensee's corrective action program as ARs 000401202 and 000401588.

.2 Maintenance Risk Assessment

a. Inspection Scope

The inspectors reviewed risk assessment and risk management for the following activity:

- Scheduled Unit 2 maintenance activity on May 16, 2000. Equipment unavailable included auxiliary feedwater discharge to Steam Generator E089 Valve 2HV4731 and CCW Pump Room 8 Emergency Cooling Unit 2ME453.

b. Issues and Findings

The inspectors identified that the guideline used by the licensee to assess the risk of planned maintenance had some incorrect risk values listed. Maintenance Policy Guideline MPG-SO123-G-31, "Utilization of the Safety Monitor in Support of Work Control," Revision 1, stated that the transition from green to yellow on the safety monitor was an instantaneous risk of 5E-5/year and that the transition from yellow to red was 2E-4/year. This guideline was used by the work window managers to take actions if risk was other than white for planned work. The safety monitor actually used 1E-4/year as the transition from normal to moderate risk, and 1E-3/year as the transition from moderate to high risk. The inspectors observed that the erroneous numbers in the maintenance guideline were not being used by the work window managers, but that the transitions on the actual safety monitor were used. Consequently, the erroneous guidance had no effect on risk management and was of very low significance. However, the maintenance guideline was the principle written guidance that work window managers used to assess and manage risk. The licensee generated AR 000500968 to address the issue.

1R14 Personnel Performance During Nonroutine Plant Evolutions

Dropped CEA - Unit 3

a. Inspection Scope

On April 7, 2000, CEA 84 dropped from the fully withdrawn position to fully inserted into the reactor core. The inspectors responded to the control room, observed operator recovery actions, and reviewed the circumstances that caused the CEA to drop.

Issues and Findings

Although allowed by procedure, the inspectors determined that licensed operators unnecessarily skipped steps in the procedure for placing a CEA on the maintenance hold bus. This omission, combined with an electrical problem, caused the CEA to drop. The dropped CEA and recovery actions resulted in a reactor power reduction of greater than 20 percent, a plant transient.

The "Control Element Drive Mechanism Control System (CEDMCS) Timer Failure" control room annunciator alarms if the control card for a particular CEA detects that the current to the CEA's upper gripper coil is outside of normal parameters. Normally, CEAs are held up by the upper gripper coil latching arms. The control card would then attempt to transfer current to the CEA's lower gripper coil. The annunciator would clear when this transfer was made. Alarm Response Instruction SO23-15-50.A2, "CEDMCS Timer Failure," Temporary Change Notice 6-1, directs the operators to transfer the affected CEA subgroup to the maintenance hold bus per Procedure SO23-3-2.19, “CEDMCS Operation,” Temporary Change Notice 13-2. The alarm response instruction also cautions the operators that high voltage applied to the CEDMCS coils for longer than 5 minutes would result in coil degradation with coil failure expected to occur within 15 minutes. If the CEDMCS timer failure annunciator is in solid, Procedure SO23-3-2.19, step 6.4.6, directs that the operators skip subsequent steps to check and, if necessary, manually transfer current to the upper gripper coils, prior to opening individual CEA circuit breakers and stopping the normal power supply. Stopping current to the upper grippers from the normal power supply could cause the CEA to fall, because current from the hold bus is not generally sufficient to latch the upper gripper in contact with the CEA lead screw. The maintenance hold bus does not provide current to the lower gripper coils.

At approximately 1:19 p.m., April 7, 2000, Unit 3 operator’s received a “CEDMCS Timer Failure” annunciator. Operators entered the alarm response procedure. The annunciator remained in solid for 4 minutes, per control operator logs. The operators skipped the steps to verify that the upper gripper coil was energized or to manually transfer current to the upper gripper coils, because the annunciator was in solid when the operators performed step 6.4.6 of Procedure SO23-3-2.19. During this occurrence, the CEA timer failure annunciator cleared prior to the operator opening the individual CEA breakers, and the operator questioned the Unit 3 control room supervisor as to whether he should continue on and open the breakers, perform the skipped steps to verify that the upper gripper coil was energized or to manually transfer the current to the upper gripper coils. The control room supervisor gave direction to open the breakers. When the breaker for CEA 84 was opened, the upper gripper was not engaged and the CEA fell into the core.

Maintenance personnel later determined that transducers that measure current to the upper and lower gripper coils had drifted from calibration due to elevated cabinet temperatures and because the zero offset of the transducers was not properly nulled. The elevated cabinet temperatures were caused by a partial loss of air conditioning due to preplanned maintenance.

The inspectors found that the operators unnecessarily skipped procedural steps that would have prevented the CEA drop. The CEA timer failure annunciator was in less than 5 minutes, indicating that there was no danger of damaging CEDMCS coils, and when the annunciator cleared this was an indication that the CEA was being held by the lower gripper coil. Transferring to the maintenance hold bus while a CEA was being held by the lower gripper coil introduced the possibility of dropping the CEA. Because the annunciator was in solid when step 6.4.6 of Procedure SO23-3.2.19 was performed, no failure to follow procedures occurred. In response to this issue and the dropped CEA, the licensee generated AR 000400462 and was considering a change to Procedure SO23-3-2.19.

The inspectors determined that the dropped CEA was a transient initiator contributor. Using the SDP, the inspectors determined that the issue was of very low significance because it did not contribute to the likelihood of a loss of coolant initiator and mitigation equipment remained operable (Green).

There were no findings identified with the operators' recovery of the plant from the dropped CEA.

1R15 Operability Evaluations

.1 General Reviews

a. Inspection Scope

The inspectors reviewed the operability evaluations documented in the following ARs:

- 000301994 CCW noncritical loop isolation valve accumulator leakage (Units 2 and 3)
- 990500775 Failure of safety injection Tank 2T008 vent Valve 2HV9345 to open (Unit 2)

b. Issues and Findings

There were no findings identified during this inspection.

.2 SWC Pump Operability Curves - Units 2 and 3

a. Inspection Scope

The inspectors reviewed an operability assessment, documented in AR 000301222, performed when Unit 3 SWC Pump 3P113 failed to meet inservice test acceptance criteria on March 20, 2000.

b. Issues and Findings

The inspectors identified that minimum SWC pump discharge pressures used by the licensee to determine pump operability were not correct and were nonconservative. The pressures were contained in a drawing used by Station Technical engineers to determine if the pump met minimum system flow requirements. The drawing failed to incorporate correct requirements for SWC pump flow as needed for SWC/CCW heat exchanger operability requirements.

On March 20, 2000, the licensee performed an inservice test for SWC Pump 3P113. The pump developed a discharge differential pressure head of 79.5 feet at 15,000 gpm, which was less than the acceptable minimum ASME Code pressure of 82.2 feet. AR 000301222 documented an operability assessment for this pump which stated that, at 15,000 gpm, required system differential pressure head was 48.5 feet. Consequently, the pump was declared operable and maintenance was scheduled to lift the pump impeller to increase developed discharge head.

The inspectors reviewed Drawing 41067, Sheet 6, Revision 1, which contained a manufacturer's pump curve and a design operability curve for SWC Pump 3P113. The x-axis was pump flow rate and the y-axis was pump developed discharge head. The licensee had drawn the design operability curve using 13,000 gpm as the minimum required SWC flow for a saltwater temperature of 76°F, the maximum anticipated temperature. Using a system curve, this 13,000 gpm would require a pump discharge head of 52.5 feet. The design operability curve was the same pump curve, drawn to intersect the 52.5 feet and 13,000 gpm point. The inspectors determined that this design operability curve was incorrect for two reasons.

First, Calculation M0027-023, "CCW/SWC Heat Exchanger Operability," Calculation Change Notice-1, was performed after the licensee performed testing of the heat exchangers in 1995. Chart 1 of this calculation was a graph of SWC flow versus SWC temperature required for heat exchanger operability, with multiple curves plotted for various heat exchanger differential pressures. For Unit 3, given a saltwater temperature of 76°F, and using a differential pressure of 9 psid (an average differential pressure), minimum SWC flow required for operability was approximately 17,000 gpm, and not the 13,000 gpm used in the design operability curve of Drawing 41067. For a flow of 13,000 gpm and 76°F saltwater temperature, the values for minimum operability from the 1995 data showed that, for any possible heat exchanger differential pressure, the system was inoperable. Using worst-case conditions, 76°F saltwater temperature and 12 psid differential heat exchanger pressure (the top of the normal operating band and the annunciation point), the system operability curve was essentially the pump curve, with no margin present.

Second, the design operability curve in Drawing 41067 was not accurate when pump developed pressure was reduced due to extreme cavitation at the pump impeller. The inspectors contacted the pump vendor, Borg-Warner Corporation, and found that using a design operability curve that was the same shape as the pump curve was not valid for those instances when the reduced discharge head was the result of cavitation, which was the most likely cause of a drastically reduced pump discharge head. This was because pump flow would decrease well below the normal shape of the pump curve when pressure at the pump impeller fell below the cavitation point. Consequently, pump flow at greater than the flow used during the inservice test (15,000 gpm), would be less than indicated on the design operability curve, resulting in an inoperable system.

The inspectors reviewed inservice testing data for both Units 2 and 3 SWC pumps for the last 2 years. No instances were identified in which inoperable SWC pumps had been declared operable by the licensee because of the issues discussed above. Operability was assessed using actual saltwater temperature and heat exchanger differential pressure, as opposed to the design maximums. Using the SDP, the inspectors determined that the issue was of very low significance because the equipment remained operable (Green).

10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires that the design basis be correctly translated into drawings. Failure to correctly translate the design of the SWC/CCW heat exchangers into the SWC Pump 3P113 operability curve is a violation of this requirement. This violation also existed for the remaining SWC pumps in Units 2 and 3. This violation of 10 CFR Part 50, Appendix B, Criterion III, is being

treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 361; 362/2000006-02). This violation is in the licensee's corrective action program as AR 000400107.

.3 SWC and CCW Systems Air-Operated Valves - Units 2 and 3

a. Inspection Scope

The inspectors reviewed the operability evaluations associated with ARs 000301969, 000401454, and 000500354, which documented the licensee's evaluation of and corrective actions for actual and potential leakage from the emergency accumulators for the SWC pump discharge isolation valves and several CCW valves.

b. Issues and Findings

The licensee determined that potential leakage from emergency air accumulators could occur after valve actuation, with loss of instrument air, that would result in some valves not remaining in their safety position. The licensee ultimately determined that the phenomenon, which had existed since original plant construction, rendered inoperable the discharge isolation valve for one SWC pump in Unit 2 since November 1998.

Before the licensee's final operability determination was completed, the licensee had determined that all SWC pump discharge isolation valves in both units, and the CCW outlet valves from the shutdown cooling heat exchangers in both units, were inoperable. Because the operability of the valves was determined incrementally, the licensee's immediate corrective actions restored operability in a manner that prevented an immediate unit shutdown.

On March 31, 2000, while performing Maintenance Order 98011611000 to replace discharge isolation Valve 3HV6200 for Train A SWC Pump 3P112, the licensee discovered an air leak on the accumulator booster valve. The licensee then inspected all seven other SWC pump discharge isolation valves (in both units) and found leakage from five other valves. The licensee determined that, upon loss of instrument air, the accumulators could depressurize and be unable to open the valves as required to mitigate events. The licensee declared the affected valves inoperable, but determined that the valves were operable when the valves were open, because the accumulators would then not be required to reposition the valves to their safety position (open). The valves were then opened. The licensee repaired the air leaks on all of the valves, completing the maintenance on April 12.

The valves are designed to fail open upon loss of instrument air, and operating procedures directed operators to verify that the valves opened. The licensee determined that the only failure mode that would fail to result in the valves opening was for the instrument air supply pressure to decrease at essentially the same rate as the accumulator pressure, which was not deemed to be a credible scenario.

On April 26 the licensee determined, based on information from EPRI Topical Report TR-103237-R2, that the balanced-disc butterfly valves could be forced closed by hydrodynamic forces if there were no torque being applied to keep the valves open. Additionally, following discussions with the valve vendor, the licensee determined that regardless of pre-actuation leakage rates, an undeterminable leakage rate could be initiated past the actuator piston seals following valve actuation. Therefore, upon a loss of instrument air, although the valves would initially open, they would not necessarily stay open. This was documented in AR 000401454. The licensee initially determined that this phenomenon only affected valves, located downstream of pipe bends, that were oriented such that the hydrodynamic forces were acting in the direction to close the valves. This condition was determined to affect the shutdown cooling heat exchanger CCW return valves for both trains in both units, for which condition the licensee entered Technical Specification 3.0.3 for approximately 25 minutes, until the affected valves were disabled in the open position using the installed manual positioner. Additionally, the discharge isolation valves for one Train B SWC pump in each unit were determined to be affected.

On April 27 the inspectors asked if the licensee's evaluation of the hydrodynamic forces on the SWC pump discharge isolation valves considered the fact that the valves were physically blocked from opening beyond 60 percent and that the effective disc area would be greater than if the valves were 100 percent open. The licensee had not considered this condition, and subsequent analysis that day concluded that the SWC pump discharge isolation valves in straight sections of piping, which included both Train A valves in both units, were inoperable. Blocking devices were installed within the 72-hour completion time of Technical Specification 3.7.8, and the valves were declared conditionally operable.

On May 5 the licensee contacted the author of the EPRI Topical Report and determined from the author's perspective that the net hydrodynamic forces would tend to close the valves regardless of orientation. The licensee then determined that the remaining two SWC pump discharge isolation valves were inoperable. AR 000500354 and Nonconformance Report 000500354 were initiated, and the licensee initiated action to block open the valves.

The licensee utilized static resistive torque data derived from air-operated valve testing and determined that all but one of the affected SWC and CCW valves would remain open, as required, upon loss of air pressure in the actuator, because the hydrodynamic torque was insufficient to overcome the resistive torque. The Unit 2 Train A SWC Pump 2P307 discharge isolation valve exhibited low resistive torque, and the licensee's calculations indicated that the valve would not remain open. Therefore, Valve 2HV6202 and its associated pump, 2P307, were inoperable since initial plant licensing.

Unit 2 Train A SWC was inoperable whenever Pump 2P307 was aligned for service, since the other Train A SWC pump breaker was racked out during those periods. This situation existed approximately half of the time, because of maintenance and equipment rotation practices. For example, Pump 2P307 was aligned for service from December 7-30, 1999, January 10-23, 2000, and January 25 through February 5, 2000. Technical Specification 3.7.8 requires that two trains of SWC be operable while operating in Modes 1-4 and it allows one train to be inoperable for up to 72 hours. Contrary to this, while Unit 2 was operating in Mode 1, Train A of SWC was inoperable for several periods in excess of 72 hours since November 1998, when the valve was last replaced. Operability prior to November 1998 has not been determined. This violation of Technical Specification 3.7.8 is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 361; 362/2000006-03). This violation was in the licensee's corrective action program as ARs 000401454 and 000500354.

The inspectors agreed with the licensee's determination that both trains of SWC were functional; however, initiating events and equipment failures that would result in a loss of instrument air were evaluated for their effect on SWC and the change in core damage frequency using the SDP. The inspectors and a senior reactor analyst established the assumptions to be used in the assessment. The following assumptions were determined to be important to this assessment.

- The Unit 2 Train A SWC Pump 2P307 discharge isolation valve would close on a loss of instrument air and isolate the associated SWC pump.

- Closure of the SWC Pump 2P307 was not recoverable.

- The redundant Unit 2 SWC Train A pump was recoverable with proceduralized operator actions established. Operations personnel performed the equipment rotations routinely and were familiar with the procedure.

- The random failure probability of the SWC pump (failure to start and failure to run) were comparable to the instrument air failure probabilities that would result in the discharge valve failing closed.

- The loss of offsite power worksheet encompassed the failure modes which would cause the discharge valve to close. The contribution of loss of reactor coolant coincident with loss of offsite power was also considered.

The inspectors and the senior reactor analyst determined that external events also needed to be considered. Specifically, the contribution from seismic and fire initiating events were considered in a Phase 3 evaluation. The NRC discussed both the results of the Phase 3 evaluation with the licensee. The licensee had performed a Phase 3 evaluation using their probabilistic risk assessment model which quantified both the internal and external contribution based on the finding. The licensee's assessment, which supported the NRC's Phase 3 analysis, determined that the delta core damage contribution from this finding had an upper bound of approximately 4E-7/yr (very low significance) (Green).

1R19 Postmaintenance Testing

a. Inspection Scope

The inspectors observed or evaluated the following postmaintenance tests to determine whether the tests adequately confirmed equipment operability:

- Maintenance Order 00030264 for replacement of CCW surge Tank T003 Train A backup nitrogen third stage pressure Regulator 3PCV6414 (Unit 3)

- Work Authorization Record 3-0000941 for preventive maintenance and calibration of Steam Generator 3E089 main steam dump to atmosphere Valve 3HV8421 (Unit 3)

b. Issues and Findings

There were no findings identified during this inspection.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed or reviewed the following surveillance activities:

- Procedure SO23-3-3.51.1, "Containment Penetration Leak Rate Testing, Containment Airlock, Purge and ILRT Penetrations," Revision 6, Attachment 6, "Pen 18 - Normal Containment Purge Inlet Valves - Volume A and IST Tests" (Unit 2)

- RCS leakrate (Units 2 and 3)

- Inservice test - auxiliary feedwater Pump 3P141 (Unit 3)

b. Issues and Findings

There were no findings identified during this inspection.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary plant modification:

- Blocking devices for SWC pump discharge isolation valves, installed per Nonconformance Report 000401454 (Units 2 and 3)

b. Issues and Findings

There were no findings identified during this inspection.

## 4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors reviewed operating logs and Nuclear Energy Institute (NEI) Document NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 0, to determine the validity of the following performance indicators for Units 1 and 2:

- SCRAMs with a Loss of Normal Heat Removal
- Safety System Functional Failures
- Reactor Coolant System (RCS) Leakage

b. Issues and Findings

On May 15, 1999, the operators manually tripped Unit 3 from approximately 24.5 percent power after a feedwater regulating valve failed open. During plant stabilization and recovery, the operators manually tripped both main feedwater pumps and initiated auxiliary feedwater for steam generator level control.

The inspectors found that the licensee had not reported this event in the Unit 3 performance indicator for a SCRAM with a loss of normal heat removal. The licensee indicated that the main feedwater pumps were secured to prevent a cooldown of the RCS. The main feedwater pumps do not automatically trip during a reactor trip and it is not a normal expected operator action to trip the pumps after all reactor trips. NEI 99-02 states that “intentional operator actions to control the reactor cooldown rate, such as securing main feedwater . . . , are not counted in the indicator.” However, the response to Frequently Asked Question 4, in NEI 99-02, suggests that, if such system actions and operator response for this plant are not normal expected actions following a reactor trip, the event would count against the indicator. Therefore, the event should have been included in the performance indicator.

The licensee submitted a frequently asked question to NEI for entry into the frequently asked question process. The inspectors identified an unresolved item pending the resolution of the accuracy of the submitted performance indicator data (URI 362/200006-04).

There were no additional findings of more than minor significance identified.

4OA5 Other

.1 (Closed) Unresolved Item 361; 362/99018-01: adequacy of design-basis assumptions for safety-related motor-operated valves. The inspectors reviewed this item and determined that no further action is required because it is a minor issue. This item has been entered into the licensee’s corrective action program as AR 991200445.

.2 (Closed) LER 361/1998-013-00: control room postloss of coolant accident dose outside design basis. LER 361/1998-013-01 was closed in NRC Inspection Report 50-361; 362/98-20; therefore, this LER is closed.

.3 (Closed) LER 361; 362/1998-015-01: nonisokinetic sampling of airborne effluent streams

The licensee identified that the condenser air ejector exhaust and containment main purge radiation monitors were not obtaining representative samples of radioactive particulate material and radioiodines as required by Technical Specification 5.5.2.3. The licensee submitted the information to the NRC in an LER dated August 13, 1998.

During NRC Inspection 50-361/98-20; 50-362/98-20, conducted December 7-11, 1998, the inspectors reviewed the licensee's finding and determined that the item was a Technical Specification violation. The item was treated as a noncited violation, consistent with the NRC Enforcement Policy in effect at the time.

On December 23, 1998, the licensee submitted a revised LER "to provide additional information." The inspectors reviewed the additional information and identified nothing that would alter its previous characterization and handling of the item.

## 4OA6 Meetings

### .1 Exit Meeting Summary

The inspectors presented the inspection results to Mr. R. Krieger and other members of licensee management at an exit meeting on May 19, 2000, and a telephonic exit on May 24, 2000. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether or not any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

## ATTACHMENT 1

## SUPPLEMENTAL INFORMATION

### PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. Allen, Supervisor, Performance Monitoring and Reliability Engineering, Site Technical Services
D. Brieg, Manager, Station Technical
G. Cook, Supervisor, Regulatory Compliance, Nuclear Oversight and Regulatory Affairs
M. Cooper, Assistant Superintendent, Operations, Units 2 and 3
J. Fee, Manager, Maintenance
J. Hedrick, Manager, Support Services, Maintenance
K. Houseman, Supervisor, Compliance, Operations
R. Krieger, Vice President, Nuclear Generation
M. McBrearty, Technical Specialist, Regulatory Compliance, Nuclear Oversight and Regulatory Affairs
D. Niebruegge, Manager, Technical Support, Station Technical
D. Nunn, Vice President, Engineering and Technical Services
A. Scherer, Manager, Nuclear Oversight and Regulatory Affairs
J. Summy, Manager, Mechanical Systems, Nuclear Engineering Design
R. Waldo, Manager, Operations
C. Williams, Supervisor, Reportability Compliance, Nuclear Oversight and Regulatory Affairs

NRC

W. Jones, Senior Reactor Analyst

### ITEMS OPENED, CLOSED, AND DISCUSSED

Opened During this Inspection

| | | |
|---|---|---|
| 362/2000005-04 | URI | reactor scram with a loss of normal heat removal not included in performance indicator (Section 4OA1.1) |

Opened and Closed During this Inspection

| | | |
|---|---|---|
| 361; 362/2000006-01 | NCV | failure to fully implement maintenance procedure (Section 1R13) |
| 361; 362/2000006-02 | NCV | failure to correctly translate SWC pump flow into operability curve (Section 1R15.2) |
| 361; 362/2000006-03 | NCV | inoperable SWC pump discharge isolation valve (Section 1R15.3) |

Previous Items Closed

| | | |
|---|---|---|
| 361; 362/1999018-01 | URI | adequacy of design-basis assumptions for safety-related motor-operated valves (Section 4OA5.1) |
| 361/1998-013-00 | LER | control room post loss of cooling accident dose outside design basis (Section 4OA5.2) |
| 361; 362/1998-015-01 | LER | nonisokinetic sampling of airborne effluent streams (Section 4OA5.3) |

LIST OF ACRONYMS USED

| | |
|---|---|
| AR | action request |
| CCW | component cooling water |
| CEA | control element assembly |
| CEDMCS | control element drive mechanism control system |
| CFR | Code of Federal Regulations |
| ECCS | emergency core cooling system |
| LER | licensee event report |
| NCV | noncited violation |
| NEI | Nuclear Energy Institute |
| NRC | Nuclear Regulatory Commission |
| RCS | reactor coolant system |
| SDP | significance determination process |
| SWC | saltwater cooling |
| URI | unresolved item |

PARTIAL LIST OF DOCUMENTS REVIEWED

Action Requests

981201499
980202571
000201165
990500775
000301760
000300342
000401268
000400464
000500662

Calculations

| | |
|---|---|
| M27.1 | SWC System Pump Sizing, Revisions 0 and 1, Calculation Change Notice 1 |
| J-EPA-002 | TLU for Saltwater Flow to CCW Heat Exchangers 2(3)E001A and 2(3)002B” |

Maintenance Orders

99041650000
99120362000
00030264000
99083321000
00030538000
00021572000
99080651000

Memoranda and Letters

Memorandum for file dated October 15, 1992, approved by S. Gosselin, Supervising Engineer, “Pump Design Operability Curves, San Onofre Nuclear Generating Station, Units 2/3"

Memorandum dated June 22, 1992, from V. Barone, “Inservice Testing of Pumps, Design Input for Saltwater Cooling Pump Operability, Units 2 and 3, San Onofre Nuclear Generating Station”

Memorandum dated January 17, 2000, from C. Williams to A. Scherer entitled “Review of SONGS LERs from 1998 to 1999 for Safety System Functional Failures”

Procedures

SO23-3-3.36.1, Attachment 1, “Annual Fire Suppression System Valve Cycle Surveillance,” Procedure Modification Permit 12-1

SO23-12-4, “Steam Generator Tube Rupture,” Revision 17

SO123-II-9.176, “Pressure Reducing Regulators Calibration,” Revision 1

SO23-3-3.51.1, “Containment Penetration Leak Rate Testing - Containment Airlock, Purge and ILRT Penetrations,” Revision 6

SO23-I-8.194.1, “Fisher Models 9211 & 9220 Butterfly Purge Valve T-Ring Replacement and Adjustment,” Revision 0

SO123-XIII-4.13, “Monthly Inspection for Control of Combustibles and Transient Fire Loads,” Temporary Change Notice 3-2

SO123-XV-4.13, “Control of Work and Storage Areas Within the Protected Area,” Revision 4

SO23-3-3.60.6, “Auxiliary Feedwater Pump 2(3)NP-141 Test,” Temporary Change Notice 6-1

SO123-XX-4, “Work Process Control,” Revision 4

SO23-XV-50, “Configuration Risk Management Program Implementation,” Revision 0

<u>Work Authorization Records</u>

3-0000885
2-0000784

<u>Updated Final Safety Analysis Report</u>

Section 9.2.1, “Saltwater Cooling System”
Section 15.6, “Decrease in Reactor Coolant Inventory”
Table 6.2-3, “Principal Containment Design Parameters”
Section 8.2.2, “Component Cooling Water System”

<u>Other</u>

Design Basis Document DBD-SO23-410, “Saltwater Cooling System,” Revision 4
Vision History Chart, Auxiliary Feedwater Pump 3P141, dated April 26, 2000

# ATTACHMENT 2

## NRC'S REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

| **Reactor Safety** | **Radiation Safety** | **Safeguards** |
|---|---|---|
| •Initiating Events | •Occupational | •Physical Protection |
| •Mitigating Systems | •Public | |
| •Barrier Integrity | | |
| •Emergency Preparedness | | |

To monitor these seven cornerstones of safety, the NRC used two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process and assigned colors of GREEN, WHITE, YELLOW, or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent little effect on safety. WHITE findings indicate issues with some increased importance to safety, which may require additional NRC inspections. YELLOW findings are more serious issues with an even higher potential to effect safety and would require the NRC to take additional actions. RED findings represent an unacceptable loss of safety margin and would result in the NRC taking significant actions that could include ordering the plant shut down.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing incremental degradation in safety: GREEN, WHITE, YELLOW, or RED. The color for an indicator corresponds to levels of performance that may result in increased NRC oversight (WHITE); performance that results in definitive, required action by the NRC (YELLOW); and performance that is unacceptable but still provides adequate protection to public health and safety (RED). GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an action matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action as described in the matrix. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.