UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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May 19, 2005

Harold B. Ray, Executive Vice President
San Onofre, Units 2 and 3
Southern California Edison Co.
P.O. Box 128, Mail Stop D-3-F
San Clemente, CA 92674-0128

SUBJECT: SAN ONOFRE NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000361/2005002; 050000362/2005002

Dear Mr. Ray:

On April 7, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your San Onofre Nuclear Generating Station, Units 2 and 3, facility. The enclosed integrated report documents the inspection findings, which were discussed on January 14 and April 7, 2005, with Mr. D. Nunn and other members of your staff.

The inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, this report documents three self-revealing findings of very low safety significance (Green). Two of these findings were determined to involve violations of NRC requirements; however, because of the very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. 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, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at San Onofre Nuclear Generating Station, Units 2 and 3, facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kriss M. Kennedy, Chief
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Division of Reactor Projects

Dockets: 50-361
50-362
Licenses: NPF-10
NPF-15

Enclosure:
NRC Inspection Report 05000361/2005002; 05000362/2005002
w/Attachment: Supplemental Information

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SISP Review Completed: _wcw___ ADAMS: : Yes ☐ No Initials: __wcw_
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RIV:RI:DRP/C	SRI:DRP/C	SPE:DRP/C	C:DRS/PSB	C:DRS/OB
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C:DRS/EB	C:DRS/PEB	C:DRP/C		
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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-361, 50-362
Licenses:	NPF-10, NPF-15
Report No.:	05000361/2005002; 5000362/2005002
Licensee:	Southern California Edison Co. (SCE)
Facility:	San Onofre Nuclear Generating Station, Units 2 and 3
Location:	5000 S. Pacific Coast Hwy. San Clemente, California
Dates:	January 1 through April 7, 2005
Inspectors:	C. C. Osterholtz, Senior Resident Inspector, Project Branch C, DRP M. A. Sitek, Resident Inspector, Project Branch C, DRP L. T. Ricketson, P.E., Senior Health Physicist, DRS
Approved By:	Kriss M. Kennedy, Chief Project Branch C Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000361/2005002, 05000362/2005002; 01/01/05 - 04/07/05; San Onofre Nuclear Generating Station, Units 2 & 3; Integrated Resident and Regional Report; Equipment Alignment, Maintenance Risk Assessment and Emergent Work, and Crosscutting Areas.

This report covered a 3-month period of inspection by resident and regional inspectors. The inspection identified three findings. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management's review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing, noncited violation of Technical Specification 5.5.1.1 was identified for the implementation of an inadequate procedure which led to the inadvertent overpressurization of the Unit 2 chemical and volume control system and the subsequent loss of approximately 370 gallons from the reactor coolant system when a relief valve lifted on February 24, 2005.

  The finding was determined to be more than minor because it was associated with the procedure quality attribute of the initiating events cornerstone. It also affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown operations. The significance of the finding was evaluated with Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process." Based on the results of the Phase 1 evaluation using Checklist 4, the finding was determined not to require quantitative assessment because adequate mitigation capability was maintained and the loss of reactor coolant system inventory was less than 2 feet (6.4 percent of pressurizer level). As a result, the finding was determined to have very low safety significance. The finding had crosscutting aspects in the area of human performance because the inadequate procedure directly contributed to the cause of the finding (Section 1R04.1).

- Green. A self-revealing finding was identified for the licensee's failure to determine the extent of condition and prevent recurrence of a Unit 2 pressurizer spray valve degraded condition preventing the pressurizer spray valve from fully closing. This deficiency resulted in a manual scram in 2002 and use of operator compensatory actions in 2005 to compensate for reactor coolant system pressure control complications. The licensee performed corrective maintenance on the valve actuator in 2004, but did not inspect the valve, which would have revealed an additional problem.

The finding was considered to be more than minor because, if left uncorrected, it would become a more significant safety concern in that an inadvertent depressurization of the reactor coolant system could occur, thus increasing the likelihood of an initiating event. Based on the results of the Significance Determination Process Phase 1 evaluation, the finding was determined to have very low safety significance (Green). Although the deficiency increased the likelihood of a reactor trip, it did not increase the likelihood that mitigating equipment or functions would not be available. This finding also had crosscutting aspects associated with problem identification and resolution, because the condition was not properly corrected when previously identified (Section 1R13.2).

Cornerstone: Mitigating Systems

- Green. A self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for the licensee's failure to prevent recurrence of the significant condition adverse to quality of missing taper pins from safety-related Fisher butterfly valves. This deficiency, which affected the operability of the component cooling water system, had been identified six times since 1993.

  The finding was more than minor because it is associated with the equipment performance attribute of the mitigating systems cornerstone and it affected the cornerstone objective by challenging the availability and capability of the containment spray system. In addition, if left uncorrected, the finding could become a more significant safety concern in that the loss of taper pins would continue to challenge the availability and capability of mitigating systems. Based on the results of the Significance Determination Process Phase 1 evaluation, the finding was determined to have very low safety significance (Green), because it did not result in an actual loss of safety function of the containment spray system. This finding also had crosscutting aspects associated with problem identification and resolution, because the extent of the condition was not properly evaluated (Section 1R13.1).

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Unit 2 began the inspection period at approximately 100 percent reactor power. On January 10, 2005, reactor power was reduced to approximately 85 percent while the Chino and Serrano off-site power lines were removed from service in order to support construction of a new substation on the electric power grid north of the plant. The off-site power line outages were completed and the unit returned to approximately 100 percent reactor power on January 22, 2005. On February 3, 2005, a Phase C differential current protection relay for Unit Auxiliary Transformer 2XU1 actuated. The main electrical generator subsequently tripped, which led to a turbine trip and ultimately a Unit 2 reactor trip. The cause of the trip was attributed to electrical testing of the protection circuitry for Transformer 2XU1 that was in progress at the time of the trip. Following successful testing of Transformer 2XU1, Operations personnel commenced a reactor startup on February 6, 2005. The unit entered Mode 1 on February 7, 2005, and returned to approximately 100 percent reactor power on February 9, 2005. On February 14, 2005, Operations personnel commenced a manual reactor shutdown in order to repair Unit 2 Train B shutdown cooling heat exchanger component cooling water return isolation Valve 2HV6500 following discovery on February 10, 2005, that the valve did not function properly. The unit entered Mode 5 on February 15, 2005, and remained at approximately 350 psia and 150EF for the duration of the repairs to Valve 2HV6500. The repairs were completed to the valve and Operations personnel commenced a reactor startup on March 7, 2005. The unit was held to approximately 80 percent reactor power while a tube leak in the condenser was repaired. Unit 2 reached approximately 99 percent reactor power on March 11, 2005, and remained at that power level to the end of the inspection period.

Unit 3 began the inspection period at approximately 70 percent reactor power while the licensee searched for the cause of an abnormal noise coming from Main Feedwater Pump Turbine 3K006. The licensee corrected the feedwater pump noise and increased reactor power to approximately 80 percent on January 10, 2005. The unit was held at approximately 80 percent reactor power, similar to Unit 2, in order to support the off-site power line outages related to the new electrical substation. The unit was returned to approximately 100 percent reactor power on January 25, 2005, following the completion of the off-site power line outages. Unit 3 remained at approximately 100 percent power to the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

1. Unit 2 Chemical and Volume Control System (CVCS) Overpressurization

a. Inspection Scope

On February 24, 2005, the inspectors performed a partial walkdown of the Unit 2 shutdown cooling (SDC) system following an inadvertent overpressurization of the CVCS system while the SDC system was crosstied to the CVCS (one inspection sample).

b. Findings

Introduction. A Green, self-revealing, noncited violation (NCV) of Technical Specification (TS) 5.5.1.1 was identified for the implementation of an inadequate procedure which led to the inadvertent overpressurization of the Unit 2 CVCS and the subsequent loss of approximately 370 gallons from the reactor coolant system (RCS).

Description. On February 24, 2005, Unit 2 was in Mode 5 with RCS pressure at approximately 350 psia. RCS temperature was being maintained at approximately 147EF by the SDC system. Charging and letdown to the CVCS had been secured in order to isolate the volume control tank for maintenance purposes. Even though charging and letdown were secured, the licensee desired to maintain CVCS purification through the ion exchangers. When the licensee aligned the SDC system with the purification portion of the CVCS, Relief Valve 2PSV9208 on the CVCS piping lifted, allowing the transfer of approximately 100 gallons per minute of RCS water to Miscellaneous Waste Tank 2T063. Operations personnel recognized the corresponding approximately 4 percent (1.25 ft) drop in pressurizer level and secured the SDC system alignment to CVCS after approximately 3 minutes in order to limit the loss of RCS inventory to approximately 370 gallons. The licensee determined that the cause of Relief Valve 2PSV9208 lifting was a direct result of aligning the SDC system to the purification portion of the CVCS with RCS pressure at approximately 350 psia. Having aligned the SDC system to the CVCS in these conditions pressurized the CVCS piping to the RCS pressure of 350 psia, which was greater than the 200 psig pressure relief setpoint of Valve 2PSV9208.

The inspectors reviewed Procedures SO23-3-2.6, “Shutdown Cooling System Operation,” Revision 21, and SO23-5-1.8, “Shutdown Operations (Mode 5 and 6),” Revision 15, which the licensee utilized at the time of the event. The procedures did not contain any guidance specifying the RCS pressure conditions that must be satisfied before the SDC system could be aligned to the purification portion of the CVCS. The procedural prerequisites only required that SDC be in service. The inspectors noted that the evolution of aligning the CVCS with SDC was normally performed when the RCS was depressurized to atmospheric conditions. The inspectors also noted that reviews by Operations personnel before the event did not identify the procedural deficiencies. The inspectors reviewed the licensee’s analysis of the effects of the overpressurization on the CVCS and determined that the structural integrity of components was not adversely affected.

The licensee implemented corrective actions by modifying Procedure SO23-3-2.6 to more clearly define the prerequisites for aligning the SDC system with the purification portion of the CVCS.

Analysis. The failure of the licensee to have an adequate procedure was determined to be a performance deficiency. The finding was determined to be more than minor because it was associated with the procedure quality attribute of the initiating events cornerstone. It also affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown operations. The significance of the finding was evaluated with Manual Chapter 0609, “Significance Determination Process,” Appendix G, “Shutdown Operations Significance Determination Process.” Based on the results of the Phase 1 evaluation using Checklist 4, the finding was determined not to require quantitative assessment because adequate mitigation capability was maintained and the loss of RCS inventory was less than 2 feet (6.4 percent of pressurizer level). As a result, the finding was determined to have very low safety significance (Green).

The finding had crosscutting aspects in the area of human performance because the inadequate procedure directly contributed to the cause of the finding.

Enforcement. TS 5.5.1.1 states, in part, that written procedures shall 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, Section 3, “Procedures for Startup, Operation, and Shutdown of Safety-Related PWR Systems,” specifies, in part, that instructions for changing the mode of operation of the SDC system should be prepared, as appropriate. Contrary to this criterion, on February 24, 2005, the licensee failed to prepare an adequate procedure for changing the mode of operation of the Unit 2 SDC system to include diversion through the purification portion of the CVCS. This violation of the TSs is being treated as an NCV (NCV 05000361/2005002-01, inadequate SDC purification procedure) consistent with Section VI.A of the Enforcement Policy. This violation is in the licensee’s corrective action program as Action Request (AR) 050201479.

2. Partial System Walkdowns

a. Inspection Scope

The inspectors performed three additional partial walkdowns during this inspection period (three inspection samples). To evaluate the operability of the selected train or system when the redundant train or system was inoperable or out of service, the inspectors checked for correct valve and power alignments by comparing positions of valves, switches and electrical power breakers to the procedures listed in the attachment as well as applicable chapters of the Updated Final Safety Analysis Report.

- On January 6, 2005, the inspectors walked down the Unit 3 Train B containment spray (CS) system while the Train A CS system was out of service for planned maintenance.

- On January 18, 2005, the inspectors walked down the Unit 2 Train B component cooling water (CCW) system while the Train A CCW system was out of service for planned maintenance.

- On January 19, 2005, the inspectors walked down the Unit 2 Train B saltwater cooling (SWC) system while the Train A SWC system was out of service for planned maintenance.

b. Findings

No findings of significance were identified

3. Complete System Walkdown

a. Inspection Scope

The inspectors conducted a detailed review of the alignment and condition of the Units 2 and 3 emergency diesel generators (EDGs) (one inspection sample). The inspectors used the licensee procedures and other documents listed in the attachment to verify proper system alignment. The inspectors also verified electrical power requirements, labeling, hanger and support installation, and associated support systems status.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors performed routine fire inspection tours, and reviewed relevant records, for the following six plant areas important to reactor safety (six inspection samples):

- Units 2 and 3 Control Room
- Technical Support Center
- Train A EDG room (Unit 2)
- Train B EDG room (Unit 2)
- Train A EDG room (Unit 3)
- Train B EDG room (Unit 3)

The inspectors observed the material condition of plant fire protection equipment, the control of transient combustibles, and the operational status of barriers. The inspectors compared in-plant observations with the commitments in portions of the Updated Fire Hazards Analysis Report.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors performed an annual visual inspection of the plant intake structure (Units 2 and 3) to determine the operational status of seals, barriers, sumps, drains, and alarms to identify the existence of any unanalyzed flooding hazards (one inspection sample). The inspectors also reviewed Updated Safety Analysis Report Chapter 3.4, “Water Level (Flood) Design,” revised June 2003.

The inspectors also performed periodic visual inspections to determine if adequate safeguards were in place for the associated risk significant structures, systems, and components. The following areas were inspected (one inspection sample):

- Units 2 and 3 SWC pump rooms

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07) - Annual Review

a. Inspection Scope

The inspectors reviewed performance tests for the Unit 2 Train A CCW Heat Exchanger S21203ME001. The inspectors reviewed Procedures SO23-2-8.1, “Saltwater Cooling System Alignments and Infrequent/Outage Operations,” Revision 2, and SO23-I-8.94, “Component Cooling Water Heat Exchanger Cleaning and Inspection,” Revision 8, and compared the test acceptance criteria with the results. The inspectors also verified that the frequency of testing was sufficient to detect degradation prior to loss of heat removal capabilities below design basis values (one inspection sample).

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

The inspectors reviewed licensed operator requalification training activities, including the licensed operators' performance and the evaluators' critique. The inspectors compared performance in the simulator on March 23, 2005 (one inspection sample), with performance observed in the control room during this inspection period.

The inspectors placed an emphasis on high-risk operator actions, operator activities associated with the emergency plan, and previous lessons-learned items. These items were evaluated to ensure that operator performance was consistent with protection of the reactor core during postulated accidents.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

1. Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed the overall implementation of the requirements of the Maintenance Rule (10 CFR 50.65) to verify that the licensee had conducted appropriate evaluations of equipment functional failures, maintenance preventable functional failures, unplanned capacity loss factor, and system unavailability. The inspectors reviewed root causes and corrective action determinations for equipment failures and reviewed performance goals for ensuring corrective action effectiveness. The inspectors discussed the evaluations with the reliability engineering supervisor and the system engineers (one inspection sample).

b. Findings

No findings of significance were identified.

2. Safety Injection System Integrated Performance

a. Inspection Scope

The inspectors reviewed the licensee's plans to improve system performance of the safety injection system (one inspection sample). As part of the inspection, the inspectors participated in an integrated discussion on equipment reliability and component aging with Engineering and Maintenance personnel to ensure that problems identified by the separate owners of particular components was shared with other responsible parties to determine the impact on overall integrated performance. The discussion members included individuals responsible for check valves, motor-operated valves, pumps, and heat exchangers, as well as the safety injection system engineer. The discussion emphasized to all the participants the value of maintaining effective interdepartmental communications.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

4. Missing Taper Pins in CCW Butterfly Valve 2HV6500

a. Inspection Scope

The inspectors reviewed emergent work associated with two missing taper pins in Unit 2 Train B SDC Heat Exchanger CCW Return Isolation Valve 2HV6500 (one inspection sample).

b. Findings

Introduction. A Green, self-revealing, NCV of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for the licensee's failure to prevent recurrence of the significant condition adverse to quality of missing taper pins from safety-related Fisher butterfly valves. This deficiency, which affected the operability of the CCW system, had been identified six times since 1993.

Description. On February 10, 2005, Operations personnel responded to a Unit 2 CCW low flow annunciator and recognized that Unit 2 Train B SDC Heat Exchanger CCW Return Isolation Valve 2HV6500 was not functioning properly. The licensee subsequently discovered that, when the valve was supposed to have been fully closed, it was passing approximately 2000 gpm of water. In addition, when the valve was supposed to have been fully open, it was passing approximately 4800 gpm of water as opposed to the expected approximate 7000 gpm. As a result of the valve malfunction, the licensee declared the Unit 2 Train B CS system inoperable and entered the appropriate 7-day shutdown action statement in TS 3.6.6.1, "Containment Spray and Cooling System." The licensee elected to shut down Unit 2 on February 14, 2005, in order to further inspect and repair the valve. The inspection of Valve 2HV6500 revealed that both taper pins that are used to connect the valve stem to the valve disk were missing. The loss of both taper pins was determined to be the cause of the valve malfunction. Two new taper pins were installed and mechanically staked to the valve disk in order to preclude them from becoming dislodged again.

The licensee had previous internal operating experience related to taper pins becoming dislodged from Fisher butterfly valves. During the Unit 3 Cycle 13 refueling outage in the 4th quarter of 2004, the licensee discovered that three 28-inch Fisher butterfly valves each had one missing taper pin. In addition, two Unit 2 28-inch Fisher butterfly valves were discovered in 1993 to each have had one missing taper pin. The NRC integrated inspection report from the 4th quarter of 2004 (NRC Inspection Report 05000361/2004005; 05000362/2004005, Section 1R13.2) describes a Green NCV for the licensee's failure to take appropriate corrective actions for the loss of taper pins in those five 28-inch Fisher butterfly valves. As a result of this internal operating experience, the licensee had previously evaluated the extent of condition and concluded that the loss of taper pins was limited to 28-inch Fisher butterfly motor-operated valves that are subjected to relatively high velocity and turbulent water flow. The licensee subsequently mechanically staked the taper pins in 16 Unit 3 8- and 28-inch Fisher butterfly valves based on the extent of condition review and the consequences of leakage associated with a valve with a missing taper pin. This criteria excluded 18-inch Valve 2HV6500 and ones similar from being considered for short-term corrective actions. The licensee failed to include, in its initial extent of condition review, valves that would lose the ability to function due to the loss of all of its taper pins. Valve 2HV6500 and ones similar were especially susceptible to this failure mode because they only had two taper pins; were not required to be leak tested; and were original plant equipment. If the licensee would have included valves where the loss of valve function could result from missing taper pins in their original extent of condition review for near-term corrective actions, they would have had opportunities to identify that Valve 2HV6500 had at least one missing taper pin by performing leak tests of the valve with the reactor online. The licensee then would have had an opportunity, following the Unit 2 reactor trip on February 3, 2005, to repair Valve 2HV6500 before the loss of both of its taper pins and subsequent failure to function properly.

During the Unit 2 forced outage to repair Valve 2HV6500, the licensee performed leak tests of 22 additional Unit 2 Fisher butterfly valves and determined that all of the tested valves did not have any missing taper pins. The population of tested valves included some of the valves where the loss of valve function from missing taper pins could have adverse consequences. The remainder of valves where the loss of valve function from missing taper pins could have adverse consequences were not tested during the Unit 2 forced outage because they either did not experience large water flows or they were used in a nonwater application.

The licensee also leak tested additional Fisher butterfly valves in Unit 3 as a result of the missing taper pins in Valve 2HV6500. The same criteria that was used to determine which Unit 2 valves were to be leaked tested was used for Unit 3. There were no additional valves in Unit 3 that were determined to have missing taper pins.

The licensee indicated that long-term corrective actions would include mechanically staking the taper pins of valves that are susceptible to losing taper pins and those valves where the loss of taper pins could have adverse consequences to the plant.

Analysis. The failure of the licensee to take appropriate corrective actions to prevent the recurrence of the loss of taper pins in Fisher butterfly valves was considered a performance deficiency. The finding was more than minor because it is associated with the equipment performance attribute of the mitigating systems cornerstone and it affected the cornerstone objective by challenging the availability and capability of the CS system. In addition, if left uncorrected, the finding could become a more significant safety concern in that the loss of taper pins would continue to challenge the availability and capability of mitigating systems. Based on the results of the Significance Determination Process Phase 1 evaluation the finding was determined to have very low safety significance (Green), because it did not result in an actual loss of safety function for affected systems.

This finding also had crosscutting aspects associated with problem identification and resolution, because the extent of the condition was not properly evaluated.

Enforcement. The regulations in 10 CFR Part 50, Appendix B, Criterion XVI, state, in part, that measures shall be established to ensure that for significant conditions adverse to quality corrective actions are taken to preclude repetition. Contrary to this criterion, the licensee failed to take appropriate corrective actions to prevent the dislodging of taper pins and the subsequent loss of function of Unit 2 Train B SDC Heat Exchanger CCW Return Isolation Valve 2HV6500 on February 10, 2005. The licensee's corrective actions in the 4th quarter of 2004 failed to properly evaluate the extent of the licensee's Fisher valve population that needed near-term corrective actions. The violation is being treated as an NCV (NCV 05000361/2005002-02, failure to prevent recurrence of missing taper pins from Fisher butterfly valves) consistent with Section VI.A of the Enforcement Policy. This violation was entered into the licensee's corrective action program as AR 050200761.

2. Pressurizer Spray Valve Malfunction

a. Inspection Scope

The inspectors reviewed emergent work associated with a Unit 2 pressurizer spray valve malfunction that occurred during a Unit 2 shutdown performed on February 14, 2005 (one inspection sample).

b. Findings

Introduction. A Green, self-revealing finding was identified for the licensee's failure to determine the extent of condition and prevent recurrence of a Unit 3 pressurizer spray valve degraded condition. This prevented the pressurizer spray valve from fully closing. This deficiency resulted in a manual scram in 2002 and use of operator compensatory actions in 2005 to compensate for RCS pressure control complications.

Description. On February 14, 2005, during a scheduled maintenance shutdown of Unit 2, Operations personnel noted that air-operated Pressurizer Spray Valve PV0100A would not fully close. The valve had stuck open approximately 4 percent. Control room operators compensated for the deficiency by manually using pressurizer heaters to maintain RCS pressure and safely shut Unit 2 down without incident. Subsequent removal and inspection of Valve PV0100A revealed that the valve had experienced excessive wear and had developed a defect on a portion of the valve piston. This defect contributed to increased friction and prevented the valve from fully closing. Maintenance personnel replaced Valve PV0100A and successfully stroked the valve at normal operating pressure prior to the Unit 2 startup performed on March 9, 2005.

The inspectors noted that Valve PV0100A had failed to fully close previously. During a Unit 2 startup performed on November 4, 2002, Valve PV0100A failed approximately 47 percent open, causing the RCS to depressurize beyond the capability for Operations personnel to compensate resulting in operators manually tripping the reactor. Unit 2 was operated with Valve PV0100A isolated until the next scheduled refueling outage (Cycle 13) that was performed in February 2004. During the Unit 2 outage, Engineering personnel performed diagnostic testing on the actuator for Valve PV0100A and discovered excessive friction on the spring loaded actuator when applied with instrument air. The actuator was replaced and tested satisfactorily. The licensee also increased the interval for preventive maintenance on the actuator from two operating cycles to one, as the licensee concluded that the major contributing factor to the problem was component wear over time. However, the licensee did not disassemble and inspect Valve PV0100A during the diagnostic testing and inappropriately concluded that the problem was limited to only the valve actuator.

The inspectors concluded that the licensee missed an opportunity to identify the wear in Valve PV0100A during the 2004 Unit 2 Cycle 13 refueling outage. Had Valve PV0100A been disassembled and inspected, the excessive wear on it would likely have been discovered and corrected prior to failure. The licensee concluded in March 2005 that the wear discovered on Valve PV0100A was likely caused by additional stresses placed on it by the faulty actuator.

<u>Analysis</u>. The failure to properly identify a significant condition adverse to quality and take corrective actions to prevent recurrence of the failure of Unit 2 Pressurizer Spray Valve PV0100A was considered a performance deficiency. The finding was more than minor because, if left uncorrected, it would become a more significant safety concern in that an inadvertent depressurization of the RCS could occur, thus increasing the likelihood of an initiating event. Based on the results of the Significance Determination Process Phase 1 evaluation, the finding was determined to have very low safety significance (Green). Although the deficiency increased the likelihood of a reactor trip, it did not increase the likelihood that mitigating equipment or functions would not be available.

This finding also had crosscutting aspects associated with problem identification and resolution, because the condition was not properly corrected when previously identified.

<u>Enforcement</u>. No violation of regulatory requirements occurred. This finding (FIN 05000361/2005002-03, failure to correct deficiencies with Pressurizer Spray Valve PV0100A) was entered into the licensee's corrective action program as AR 021100192.

3. Quarterly Assessment

a. Inspection Scope

The inspectors verified the accuracy and completeness of risk assessment documents and that the licensee's maintenance risk assessment program was being appropriately implemented. The inspectors also ensured that plant personnel were aware of the appropriate licensee established risk categories for maintenance activities, according to the risk assessment results and licensee program procedures.

The inspectors also reviewed selected emergent work items to ensure that overall plant risk was being properly managed and that appropriate corrective actions were being properly implemented.

The inspectors reviewed the effectiveness of risk assessment and risk management for the following four activities (four inspection samples):

- Unit 3 Breaker 3B01805 operating mechanism cotter pin missing (AR 050100972)
- Unit 3 Train B Shutdown Cooling Heat Exchanger CCW Valves 3HV6500 and 3HCV6547 leakage (AR 050301068)
- Units 2 and 3 steam bypass control system header cracking (AR 050200923)
- Unit 3 Main Feedwater Block Valve 3HV4051 hydraulic leak (AR 050101113)

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions (71111.14, 71153)

a. Inspection Scope

The inspectors reviewed operator response to nonroutine events during the inspection period. In addition to direct observation of operator performance, the inspectors reviewed procedural requirements, operator logs, and plant computer data to determine that the response was appropriate with that required by procedures and training. The following two operator responses were reviewed (two inspection samples):

- On February 3, 2005, the inspectors observed the site response to an automatic Unit 2 reactor trip. Unit Auxiliary Transformer 2XU1 tripped due to the actuation of its Phase C differential relay causing the main generator to trip. The main generator trip resulted in a turbine trip and ultimately the reactor trip. The inspectors observed Operations personnel respond to the event and effectively place the unit in a stable shutdown configuration.

- On February 24, 2005, the inspectors reviewed and discussed with Operations personnel the site response to an inadvertent loss of approximately 370 gallons from the RCS. During outage conditions, operators placed SDC purification in service when the RCS was pressurized to approximately 350 psia and the volume control tank was bypassed. In this configuration, the pressure breakdown of the RCS did not occur and CVCS Relief Valve 2PSV9208 lifted at its 200 psia setpoint, transferring approximately 370 gallons from the RCS to miscellaneous Radioactive Waste Tank 2T063. Operations personnel recognized the abnormal situation and secured SDC purification within approximately 3 minutes in order to terminate the lifting of the relief valve and subsequent transfer of the RCS to Tank 2T063.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed selected operability evaluations to evaluate technical adequacy and to verify that operability was justified. The inspectors considered the impact on compensatory measures for each condition being evaluated, and referenced the Updated Final Safety Analysis Report and TSs. The inspectors also discussed the evaluations with cognizant licensee personnel.

The inspectors reviewed five operability evaluations and cause assessments documented in the following ARs to ensure the operability was properly justified (five inspection samples):

- AR 031200992, Unit 3 dc Battery 3B009 operability following loss of its battery charger
- AR 050100590, Emergency Operating Facility and Alternate Emergency Operating Facility Operability (Units 2 and 3)
- AR 050101003, Units 2 and 3 site halon system operability
- AR 050100219, Unit 3 turbine-driven auxiliary feedwater Pump 3P140 overspeed trip indication setpoint drift
- AR 050200310, Unit 3 Train A High Pressure Safety Injection Pump 3P017 inboard bearing oil leak

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

Cumulative Effects. The inspectors reviewed six (one inspection sample) operator workaround items to evaluate their cumulative effects on the reliability, availability, and potential for misoperation of a system and on the ability of operators to respond in a correct and timely manner to plant transients and accidents. The inspection included a review of the licensee's criteria and processes used for identifying and tracking deficiencies as operator workarounds. The review also focused on the length of time the identified workarounds had been in existence and the efforts initiated to resolve them.

Individual Effects. The inspectors reviewed the following operator workaround (one inspection sample) to determine if the functional capability of the system or human reliability in responding to an initiating event was affected by the workaround. The inspectors evaluated the effect that the operator workaround had on the operator's ability to implement abnormal or emergency operating procedures.

- Loss of function of Unit 2 Train A EDG Air Start Compressor 2MC012A results in the need to periodically crosstie the two air start system receiver tanks in order to maintain adequate air pressure.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

In March 2005, the inspectors reviewed a permanent plant modification to the Units 2 and 3 EDGs. The modification installed additional protective relaying to prevent a noninterruptible power supply ground from inadvertently tripping an EDG prematurely. The inspectors reviewed Engineering Change Procedure 050101702, "Modify Diesel Generator System Ground Protection Relay." In addition, the inspectors discussed the modification with cognizant Engineering and Maintenance personnel.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors observed and/or reviewed postmaintenance testing for the following seven activities to verify that the test procedures and activities adequately demonstrated system operability (seven inspection samples):

- Units 2 and 3 Train B control room emergency air cleanup system postmaintenance test per Procedure SO-23-3-3.20, “Control Room Emergency Air Cleanup System Test,” Revision 17, performed on January 13, 2005

- Unit 2 Train A SWC Pump 2P307 Discharge Check Valve 2MU011 postmaintenance test per Procedure SO23-3-3.60.4, “Saltwater Cooling Pump and Valve Testing,” Revision 7, performed on January 20, 2005

- Unit 2 Channel C pressurizer pressure lumigraph postmaintenance test per Maintenance Order 05012368000, performed on January 31, 2005

- Unit 2 Train B Shutdown Cooling Heat Exchanger CCW Return Isolation Valve 2HV6500 postmaintenance test per Procedure SO23-3-3.30, “Component Cooling Water System On-Line Valve Test,” Revision 10, performed on February 3, 2005

- Unit 3 Train A high pressure safety injection Pump 3P017 postmaintenance test per Procedure SO23-3-2.7, “Safety Injection System Operation,” Revision 20, performed on February 8, 2005, following corrective maintenance to repair an oil leak

- Unit 3 125 Vdc Battery 3B009 postmaintenance test per Procedure SO123-I-2.2, “125 VDC Pilot Cell Battery Inspection,” Revision 6, Procedure SO123-I-2.3, “125VDC Battery Inspection,” Revision 6, and Procedure SO123-I-2.5, “Battery Service Test and Rapid Recharge,” Revision 8, completed on March 1, 2005, following replacement of Battery 3B009

- Unit 2 CCW Valve 2HV6226A postmaintenance test per Procedures SO123-I-9.30, “Motor Operated Valve Analysis and Test System,” Revision 5, and SO123-I-9.5, “Electrical Inspection of Limitorque Actuators,” Revision 5, completed on March 3, 2005

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors periodically observed and reviewed shutdown activities during the Unit 2 forced outage (one inspection sample) to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense in depth. The inspectors also verified that activities were performed in accordance with approved procedures and TS requirements.

The inspectors periodically evaluated plant conditions to verify that safety systems were properly aligned and that maintenance activities were controlled in accordance with the outage risk control plan. The inspectors verified that RCS inventory was properly controlled and that containment closure requirements were met. The inspectors also performed an independent inspection of containment prior to entry into Mode 3.

The following activities were evaluated:

- Plant shutdown in accordance with Procedure SO23-5-1.4, “Plant Shutdown to Hot Standby,” Revision 11
- Plant cooldown in accordance with Procedure SO23-5-1.5, “Plant Shutdown from Hot Standy to Cold Shutdown,” Revision 24
- Shutdown operations in accordance with Procedure SO23-5-1.8, “Shutdown Operations (Mode 5 and 6),” Revision 15
- Containment inspection prior to startup in accordance with Procedure SO123-V-8.15, “Boric Acid Leak Inspection,” Revision 0
- Plant startup in accordance with Procedures SO23-5-1.3, “Plant Startup from Cold Shutdown to Hot Standby,” Revision 28, and Procedure SO23-5-1.3.1, “Plant Startup from Hot Standby to Minimum Load,” Revision 23

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed and/or reviewed performance and documentation for the following five surveillance tests to verify that the structures, systems, and components were capable of performing their intended safety functions and to assess their operational readiness (five inspection samples):

- Unit 3 CS Pump 3P012 surveillance test per Procedure SO23-3-3.60.7, "Containment Spray Pump and Valve Testing," Revision 7, performed on January 6, 2005

- Unit 2 CCW Pump 2P024 surveillance test per Procedure SO23-3-3.60.3, "Component Cooling Water and Seismic Makeup Pump Test," Revision 5, performed on January 10, 2005

- Unit 2 Auxiliary Feedwater Pump 2P504 surveillance test per Procedure SO23-3-3.60.6, "Auxiliary Feedwater Pump and Valve Testing," Revision 10, performed on January 26, 2005

- Unit 2 Mode 3 containment walkdown performed per Procedure SO23-V-8.15, "Boric Acid Leak Inspection," Revision 0, performed on February 15, 2005

- Unit 2 CCW pump surveillance test per Procedure SO23-3-3.60, "Component Cooling Water Pump 2P026 Test," Revision 5, performed on February 22, 2005

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following temporary plant modification to verify that the safety functions of safety systems were not affected (one inspection sample):

- Alignment of 125 Vdc Battery B00X to 125 Vdc Bus 3D3 during replacement of 125 Vdc BTemporary Engineering Change Package 001000280-77.

b. Findings

No findings of significance was identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed the following emergency preparedness drill to evaluate the drill conduct and the adequacy of the licensee's performance critique. The inspectors observed one site-wide drill from the simulator and the Emergency Operating Facility on the following date (one inspection sample):

- March 9, 2005

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspector assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspector used the requirements in 10 CFR Part 20 and the licensee's procedures required by TSs as criteria for determining compliance. The inspector interviewed licensee personnel and reviewed:

- Current 3-year rolling average collective exposure
- Site-specific ALARA procedures
- Four work activities of highest exposure significance completed during the last outage.
- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements
- Intended versus actual work activity doses and the reasons for any inconsistencies
- Assumptions and basis for the current annual collective exposure estimate, the methodology for estimating work activity exposures, the intended dose outcome, and the accuracy of dose rate and man-hour estimates
- Method for adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered
- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding

- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas

- Corrective action documents related to the ALARA program and followup activities such as initial problem identification, characterization, and tracking

The inspector completed 9 of the required 15 samples and 1 of the optional samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

1. Annual Sample Review

a. Inspection Scope

The inspectors selected AR 050301016 for detailed review (one inspection sample). This AR was written after Unit 2 Boric Acid Makeup Pump 2P175 could not be stopped from the control room.

b. Findings and Observations

No findings of significance were identified. However, the inspectors noted that AR 050301016 was closed without any corrective actions identified or documented. After interviewing several licensee personnel, the inspectors discovered that the failure of a Square D Class 8501 relay had caused the problem. The relay had been sent to Electrical Maintenance personnel for troubleshooting and failure evaluation, and that work was still in progress at the end of the inspection period. The licensee reopened AR 050301016 to create a field support assignment to document the logic and results of the troubleshooting efforts. The inspectors considered the licensee’s followup actions appropriate.

2. Quarterly Review of Corrective Action Documents

a. Inspection Scope

The inspectors reviewed a selection of Action Requests written during this period to determine if the licensee was entering conditions adverse to quality into the corrective action program at an appropriate threshold to determine if the ARs were appropriately categorized and dispositioned in accordance with the licensee's procedures, and, in the case of conditions significantly adverse to quality, to determine if the licensee's root cause determination and extent of condition evaluation were accurate and of sufficient depth to prevent recurrence of the condition.

b. Findings

No findings of significance were identified.

3. Cross-References to Problem Identification and Resolution Findings Documented Elsewhere

Section 1R13.1 describes a finding for a failure to take appropriate corrective actions to prevent taper pins from becoming dislodged from Fisher butterfly valves. The licensee's corrective actions in 2004 did not properly evaluate the extent of the valve population that could be susceptible to losing taper pins.

Section 1R13.2 describes a finding for a failure to take appropriate corrective actions to ensure operability of a Unit 2 pressurizer spray valve. The licensee's corrective actions taken in February 2004 to prevent the spray valve from sticking open in response to a Unit 2 RCS depressurization and reactor trip did not prevent the valve from sticking open again in February 2005.

4. ALARA Review

a. Inspection Scope

Section 2OS2 evaluated the effectiveness of the licensee's problem identification and resolution processes regarding exposure tracking, higher than planned exposure levels, and radiation worker practices. The inspector reviewed the corrective action documents listed in the attachment against the licensee's problem identification and resolution program requirements.

b. Findings

No findings of significance were identified.

4OA3 Event Followup (71153)

1. (Closed) Licensee Event Report (LER) 05000362/2003-001-00: Breaker failure coincident with planned maintenance results in both trains of emergency core cooling system (ECCS) and CS being inoperable

On December 17, 2003, Unit 3 Train A feeder Breaker 3B0414 unexpectedly tripped open, which resulted in the loss of power to various ECCS and CS components. Prior to the breaker failure, various Unit 3 Train B ECCS and CS components had been taken out of service for planned maintenance. As a result, Unit 3 entered TS 3.0.3 for two trains of ECCS and CS being inoperable. The licensee replaced the faulty breaker with a tested spare and exited TS 3.0.3. In addition, a surveillance was successfully performed on 125 Vdc Battery 3B009 because it had partially discharged when the breaker failed. The inspectors, with assistance from the Region IV Division of Reactor

Safety and NRC Headquarters personnel, reviewed the battery surveillance and the LER. The NRC did not identify any findings of significance. The licensee documented the equipment failure in AR 031200992. This LER is closed.

2. (Closed) LER 05000362/2004-003-00: Invalid Actuation of EDG due to Invalid Signal

On December 2, 2004, a maintenance technician inappropriately installed an electrical jumper in a Unit 3 engineered safety features actuation system relay cabinet during the Cycle 13 refueling outage. As a result, the Unit 3 Train A EDG started and the automatic crosstie feature between the Unit 3 Train A Class 1E 4kV electrical safety bus and the Unit 2 Train A Class 1E 4kV electrical safety bus was lost. The EDG was secured and the automatic crosstie feature of the safety buses was reestablished. A Green NCV was documented in Section 1R04.2 of San Onofre Nuclear Generating Station - NRC Integrated Inspection Report 05000361/2004005; 05000362/2004005 for the failure of a maintenance technician to follow the instructions in a maintenance order. The inspectors reviewed the LER and did not identify any additional findings of significance. The licensee documented the event in AR 041200074. This LER is closed.

3. (Closed) LER 05000361/2004-004-00: Automatic Reactor Trip Due to Electrical Ground on Main Generator Isophase Bus

On November 19, 2004, Unit 2 was at approximately 100 percent power when the main generator and turbine automatically tripped, triggering an automatic reactor trip. The licensee determined that a modification performed on the main generator terminal box in April 2004 contained de-ionization plates that resonated with the turbine frequency of 1800 rpm. This caused excessive stress on the plates and prompted their premature failure, causing a momentary short circuit between two phases of the main generator's output, which resulted in the automatic trip. The licensee modified the design of the de-ionization plates to prevent future degradation. The licensee implemented the modification to Unit 2 prior to its restart and to Unit 3 prior to startup from its scheduled Cycle 13 refueling outage. The inspectors reviewed the licensee's root cause evaluation and corrective actions and considered them appropriate. This LER is closed.

4OA4 Crosscutting Aspects of Findings

Cross-References to Human Performance Findings Documented Elsewhere

Section 1R04 describes a finding where the implementation of an inadequate procedure led to the inadvertent lifting of a relief valve in the Unit 2 CVCS which resulted in the transfer of approximately 370 gallons from the RCS while on SDC.

4OA6 Meetings, Including Exit

On January 14 and April 7, 2004, the inspectors presented the inspection results to Mr. D. Nunn and others who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

C. Anderson, Manager, Site Emergency Preparedness
D. Axline, Engineer, Nuclear Regulatory Affairs
J. Barrow, Supervisor, Health Physics
E. Bennett, Nuclear Oversight and Assessment
D. Breig, Station Manager
R. Corbett, Manager, Health Physics
M. Farmer, Supervisor, Health Physics
M. Love, Manager, Maintenance
A. Martinez, Supervisor, Health Physics
C. McAndrews, Manager, Nuclear Oversight and Assessment
D. Nunn, Vice President, Engineering and Technical Services
N. Quigley, Manager, Mechanical/Nuclear Maintenance Engineering
A. Scherer, Manager, Nuclear Regulatory Affairs
R. Schofield, Supervisor, Health Physics
M. Short, Manager, Systems Engineering
T. Vogt, Manager, Operations
R. Waldo, Vice President, Nuclear Generation
J. Wambold, Vice President, Nuclear Generation
D. Wilcockson, Manager, Plant Operations
T. Yackle, Manager, Design Engineering

NRC personnel

Christian Araguas, Nuclear Safety Professional Development Program Participant
Matthew McConnell, Electrical Engineer, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000361/2005002-01	NCV	Inadequate SDC purification procedure (Section 1R04.1)
05000361/2005002-02	NCV	Failure to prevent recurrence of missing taper pins from Fisher butterfly valves (Section 1R13.1)
05000361/2005002-03	FIN	Pressurizer spray valve malfunction (Section 1R13.2)

Closed

05000362/2003-001-00	LER	Breaker failure coincident with planned maintenance results in both trains of ECCS and CS being inoperable (Section 4OA3.1)
05000362/2004-003-00	LER	Invalid Actuation of Emergency Diesel Generator due to Invalid Signal (Section 4OA3.2)
05000361/2004-004-00	LER	Automatic Reactor Trip Due to Electrical Ground on Main Generator Isophase Bus (Section 4OA3.3)

Discussed

None

LIST OF DOCUMENTS REVIEWED

In addition to the documents called out in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Section 1R04: Equipment Alignments

Procedures

SO23-3-2.9, “Containment Spray System Operation,” Revision 22

SO23-2-17, “Component Cooling Water System Operation,” Revision 18

SO23-2-17.1, “Component Cooling Water System Alignments,” Revision 6

SO23-2-8, “Saltwater Cooling System Operation,” Revision 25

SO23-2-8.1, “Saltwater Cooling System Alignments and Infrequent/Outage Operations,” Revision 2

Procedure SO23-3-3.23, “Diesel Generator Monthly and Semi-annual Testing,” Revision 23

Procedure SO23-2-13, “Diesel Generator Operation,” Revision 25

Procedure SO23-2-13.1, “Diesel Generator Alignments,” Revision 1

Drawings

Piping and Instrument Diagram 40114ASO3, “Containment Spray System,” Revision 14

Piping and Instrument Diagram 40114BSO3, “Containment Spray System,” Revision 14

Piping and Instrument Diagram 40127A, “Component Cooling Water System (Pumps),” Revision 27

Piping and Instrument Diagram 40127B, “Component Cooling Water System (Tanks),” Revision 33

Piping and Instrument Diagram 40127C, “Component Cooling Water System (Heat Exchangers),” Revision 39

Piping and Instrument Diagram 40126A, “Component Cooling Water System (Saltwater Pumps),” Revision 26

Piping and Instrument Diagram 40126B, “Component Cooling Water System (Saltwater Pumps),” Revision 27

Section 2OS2: ALARA Planning and Controls (71121.02)

Corrective Action Documents (Action Requests)

040901838, 041001372, 041001927, 041100453, 041100852

ALARA Work Activity Packages

Pressurizer Nozzle Repair (A 1024040001)
Reactor Head Repairs (A 1008040001)
Steam Generator Primary Work (A 1020000026)
Reactor Disassembly/Reassembly (A 1010020002)

Procedures

SO123-VII-20.4	ALARA Program, Revision 3
SO123-VII-20.4.3	ALARA Job Reviews, Revision 4
SO123-VII-20.10	Radiological Work Planning and Controls, Revision 9

ALARA Committee Meeting Minutes

3rd Quarter, 2004
4th Quarter, 2004

LIST OF ACRONYMS

ALARA	as low as is reasonably achievable
AR	action request
CCW	component cooling water
CFR	*Code of Federal Regulations*
CS	containment spray
CVCS	chemical and volume control system
ECCS	emergency core cooling system
EDG	emergency diesel generator
LER	licensee event report
NCV	noncited violation
RCS	reactor coolant system
SDC	shutdown cooling
SWC	saltwater cooling
TS	Technical Specifications