APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-361/94-08
50-362/94-08

Operating Licenses: NPF-10
NPF-15

Licensee: Southern California Edison Company
Irvine Operations Center
23 Parker Street
Irvine, California 92718

Facility Name: San Onofre, Units 2 and 3 (SONGS)

Inspection At: San Onofre, San Clemente, California

Inspection Conducted: March 8 through April 18, 1994

Inspectors: J. A. Sloan, Senior Resident Inspector
J. J. Russell, Resident Inspector
D. L. Solorio, Resident Inspector

Accompanying Personnel:

Approved By: H. J. Wong, Chief, Project Branch F — 6/1/94 Date Signed

Inspection Summary

Areas Inspected (Units 2 and 3): Routine, announced, resident inspection of onsite followup of events, operational safety verification, maintenance observations, emergency planning exercises, simulator observations, postfire safe shutdown capability, followup, and followup of licensee event reports.

Results (Units 2 and 3):

Operations:

The licensee's performance in Operations during this inspection period was generally strong. Operations and management response to two minor events (a hydrogen leak and a failed steam pressure root valve) was good. However, a violation was identified for failing to implement thorough corrective actions, and some procedural and logkeeping deficiencies were identified.

- Operator response to stop a hydrogen leak from the main generator cooling system was prompt and correct, preventing a serious operational and industrial safety problem from developing (Section 3.1).

- A violation was identified in that the licensee failed to implement effective corrective actions following a February 1992 event in which containment pressure increased and forced water out of the reactor cavity and into the spent fuel pool. A similar event in October 1993 occurred, resulting in reactor cavity water level decreasing below the Technical Specification limit (Section 8.5).

- Several inconsistencies between the operational procedures for "Fire" and "Shutdown from Outside the Control Room" were identified, including the use of different compensation curves for cold-calibrated instruments (Section 7.1).

- An Emergency Operating Instruction deviation from the owners' group guidance was not identified and justified in the licensee's deviation document (Section 6.1).

- A noncited violation was identified because the licensee failed to ensure that the procedure for orienting emergency lights was effectively implemented. Five lights were found misdirected the day after the surveillance procedure was performed (Section 7.3).

Maintenance

Maintenance performance during this inspection period was average. The material condition of the units appeared to be good, and maintenance activities appeared to promptly address deficiencies effecting operations. However, several examples of minor procedural deficiencies were noted, and a Maintenance Department evaluation of an improperly assembled component was not thorough.

- A noncited violation was identified in that an inadequate procedure resulted in the improper assembly of a Kirk key interlock, leaving the mechanical interlock disabled for over 4 months (Section 4.1).

- A Maintenance Division investigation of the improper assembly of a Kirk key interlock was weak in that the licensee did not attempt to interview the workers who performed the assembly (Section 4.1).

- A noncited violation was identified in that electricians reassembling a charging pump failed to follow a procedure requiring signing of a completed procedural step before performing the next step (Section 4.3).

- The charging pump maintenance procedure was poorly written in that it provided confusing instructions regarding the assembly sequence for the three plungers (Section 4.3).

- The licensee did not consider the effects of backpressure in determining the relief setpoint for a fire pump discharge relief valve (nonsafety-related) which relieves against an approximately 10 psi head (Section 4.4).

- A noncited violation was identified in that the licensee procedure for assembly of a valve was inadequate, resulting in misassembly of the valve. The procedure was corrected in 1990 (Section 8.3).

Engineering

Engineering performance during this inspection period was mixed. Strong involvement in resolution of high bearing temperatures on high pressure safety injection Pump 3P019 was observed. Early engineering involvement in operations and maintenance issues was frequently observed during this period. A violation was identified for untimely corrective actions related to an abnormal motor-operated valve test result.

- A violation was identified in that the licensee failed to take appropriate and timely corrective actions when a motor-operated valve diagnostic test result was found to be abnormal. The valve operator subsequently failed, and the valve was found to have been misassembled (Section 8.3).

Plant Support

Performance in the Plant Support functional area during this inspection period was generally good. The quarterly emergency preparedness drill successfully demonstrated a site evacuation. However, actions related to evaluation of fire damper capability appeared to be slowly implemented. Radiological Protection performance appeared sound, promptly addressing some minor examples of contamination area boundaries being compromised. No Security deficiencies were noted.

- Communications in the Technical Support Center during an emergency plan exercise were good. Additionally, the licensee successfully demonstrated site evacuation capability during the exercise (Section 5).

- The licensee was slow to resolve potential problems with fire dampers, which were identified in a 1989 NRC Information Notice. Procedural modifications have not yet been implemented, and the dampers have not yet all been tested to ensure their ability to close under flow conditions or to ensure flow is secured so that the dampers will close when required (Section 8.4.1).

Summary of Inspection Findings:

- Four noncited violations were identified (Sections 4.1, 4.3, 7.3, and 8.3).
- Two examples of a violation (362/9408-01) were identified (Sections 8.3 and 8.5).
- Inspector Followup Items 361/9319-04 and 361/93-2601 were closed (Sections 8.1 and 8.2).
- Unresolved Items 361/9331-03, 361/9331-04, and 362/9331-06 were closed (Sections 8.3, 8.4, and 8.5).
- Licensee Event Reports 361/93-05, Revisions 0 and 1, and 361/94-01, Revision 0, were closed (Section 9).

Attachments:

- Persons Contacted and Exit Meeting
- Acronyms

DETAILS

1 PLANT STATUS (71707)

1.1 Unit 2

The unit operated at approximately 98 percent of rated thermal power throughout the period, with the exception of downpowering to 80 percent on March 26, 1994, in support of heat treatment of the circulating water system.

1.2 Unit 3

The unit began the inspection period at approximately 97 percent of rated thermal power. On March 30, 1994, the bonnet of an instrument root valve for first stage pressure (high pressure turbine) became disengaged from its valve body. As a result, on April 2, 1994, power was reduced to approximately 15 percent of rated thermal power in order to facilitate repairs of the valve (Section 2). Approximately 96 percent power was reached on April 4, 1994, and was maintained until April 16, when the unit reduced power for 1 day to 80 percent to support heat treatment of the circulating water system. The unit ended the inspection period operating at approximately 96 percent of rated power.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Steam Leak on High Pressure Turbine Instrument Root Valve 3MR40

On March 30, 1994, an auxiliary operator was attempting to close Valve 3MR40, a 3/4-inch root isolation valve for Pressure Transmitter 3PT-2052D for Main Steam Inlet D to the Unit 3 high pressure turbine. The operator was closing the valve in preparation to reinstall a Furmanite injection port on the outside of the valve. A leak from the valve stem had been previously repaired by Furmanite in January 1994. The valve bonnet, which screwed into the valve body, separated from the body as the operator was operating the valve and injured the operator. There were no significant effects on the plant primary or secondary systems. The operator was transported from the site and later recovered from nonserious injuries. On April 2, 1994, the licensee downpowered Unit 3 and repaired the steam leak that resulted when the valve failed. The inspector visually inspected the cap that had been welded to the pipe stub to repair the leak and considered it adequate The licensee was conducting a division investigation and analyzing parts of the valve for the failure mechanism at the end of the inspection period. The inspector will review the results of this investigation during an upcoming inspection.

2.2 Conclusions

The inspector concluded that the licensee's response appropriately considered industrial and nuclear safety concerns and that the ongoing engineering investigation was warranted.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Main Generator Cooling System Hydrogen Leak

On March 24, 1994, while at 98 percent power, Unit 3 control room operators received main generator differential pressure and gas pressure low alarms (at approximately 1:10 p.m.). A plant operator on rounds in the turbine building heard a leak from a hydrogen gas drying system condensing tank and isolated the leak. After operators re-established control of hydrogen pressure, the alarms cleared. Emergency response personnel arrived and determined that explosive levels of hydrogen were not present. The inspector concluded that the plant equipment operator's prompt response and appropriate actions to isolate a hydrogen leak from the main generator hydrogen system were a good.

The cause of the leak was a broken condensing tank drain line. The inspector walked down the Unit 2 condensing tank and noted that its configuration was different than that in Unit 3. Based on the additional support provided for the line, the inspector considered that a similar failure of the line in Unit 2 was less likely. Subsequently, the drain line in Unit 3 was replaced. The licensee stated that the reason for the difference in installation between the units was not documented and could not be explained. The licensee stated that a root cause evaluation of the failed valve would be performed to assess the failure mode and that the information would be used to develop long-term corrective actions. At the end of the inspection period, the licensee preliminarily concluded that the line did not fail due to overload. The inspector considered that the licensee's completed and proposed corrective actions were adequate.

3.2 Operator Logs - Unit 2

On March 18, 1994, the inspector reviewed control operator logs for Unit 2. The inspector noted that on March 17 operators had logged the removal of the plant monitoring system core operating limits supervisory system for maintenance. In accordance with the work authorization record, which controlled the clearance, maintenance, retest, and return to service of the equipment, operators were required to perform Attachment 11, "CCW [component cooling water] Surge Tank Level - 2 Hour Monitoring," of Station Procedure SO23-3-3.25, Temporary Change Notice (TCN) 8-41, "Once A Shift Surveillance Modes 1-4." The inspector noted that the operators had logged the initiation of Procedure SO23-3-3.25, Attachment 15, "Containment Sump Inlet Flow - Alternate Surveillance." The inspector verified that Attachment 11 had actually been performed and concluded that operators had simply logged the wrong attachment number. The inspector considered this an isolated incident.

The inspector performed a review of Unit 2 control operator logs from November 1993 through April 15, 1994, and considered that, in general, logs entries were consistently made which reflected operator understanding of loggable events and occurrences. However, the inspector noted that the equipment status page, which was normally made as the first entry of the day, did not consistently include status on all components. Specifically, the status of saltwater cooling (SWC) pumps was not always indicated. The inspector noted that he understood that the management expectation was that the status of the pumps be indicated as on, off, or out of service. The inspector noted that operations supervision (control room supervisor and shift superintendent) routinely reviewed operator logs and should have identified the inconsistent documentation. The inspector also noted that the status of individual pumps was logged whenever the status changed. The licensee acknowledged the inspector's comments and agreed to discuss management expectations for log keeping and log review with appropriate supervisors.

3.3 Emergency Diesel Generator (EDG) Governor Oil Level

On March 17, 1994, the inspector observed that the oil level in the Woodward governor for EDG 3G003 was not visible in the sightglass and appeared to be just above the top of the sightglass. A placard at the governor stated that the level must be above the midpoint and between 1/16 and 1/8 inch from the top of the sightglass. Upon notification, the licensee immediately drained a small quantity of oil from the governor to restore the level to the appropriate band. The inspector also checked the other EDGs and confirmed the governor oil levels were acceptable.

The inspector discussed the condition with Operations and Engineering personnel and agreed with the licensee's determination that the level was not high enough to cause operational problems with the governor. If the level had been higher, it could have caused operational problems (oil frothing leading to governor instability. The licensee was unable to explain why the level was high or why operators had not noted the condition even though the level is specifically monitored during shiftly rounds. The licensee discussed with the operators the importance of careful and accurate log taking.

The inspector also discussed the meaning of the posted level band with the licensee. The operators' electronic logs indicate the band is from the midpoint to 1/16 inch below the top of the sightglass. The inspector questioned an operator who stated that he used the limits on the electronic log and not the placard, but that the placard was somewhat confusing.

The inspector concluded that the high level was operationally insignificant, but that operators had not carefully observed the level during log taking. The inspector concluded that the licensee's actions to drain some of the oil and to discuss the need for careful log taking were adequate.

3.4 Plant Walkdowns

The inspector noted four instances of objects being partially in posted contamination areas. These were as follows:

Date(1994)	Area	Object
March 8	Unit 3, Room 17	Tool cart
March 29	Unit 3, Charging Pump P192 room	Paperwork
March 30	Unit 3, AFW room	Unsecured rope
April 14	North gas stripper, Room 505L	Ladder

In each instance, the inspector informed Health Physics personnel, and prompt corrective actions were taken. During a recent inspection period from January 1-31, 1994, the inspector found seven similar examples which were documented in NRC Inspection Report 50-361/94-02, 50-362/94-02. The licensee had previously confirmed that this practice was not in accordance with management expectations, as unsecured objects crossing contaminated area boundaries could spread the contamination to the "clean" side of the boundary. The inspector considered that the number of observed occurrences had decreased and concluded that licensee efforts to minimize these occurrences had been somewhat effective. The inspector will continue to monitor this area during routine inspections.

3.5 Conclusions

The inspector concluded that the plant equipment operator's prompt response and appropriate actions to isolate a hydrogen leak from the main generator hydrogen system were good, and that the licensee completed and proposed corrective actions were appropriate.

The inspector concluded that numerous control room logs between November 1993 and April 1994 were not always fully complete in that the status of SWC pumps was not indicated.

The inspector concluded that operators failed to accurately read and log the oil level in the Woodward governor for Diesel Generator 3G003, but that the high level was not technically significant.

The inspector concluded that continued licensee effort is warranted to continue to reduce the number of incidents of material being left laying partly in and partly out of contaminated areas.

4 PLANT MAINTENANCE (62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance/quality control department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. The inspector verified that reportability for these activities was correct.

Specifically, the inspector witnessed portions of the following maintenance activities:

Unit 2

- Calibrate low pressure safety injection pump Flow Indicator FI-0306
- Remove and replace SWC Pump P114 motor for overhaul
- Restore SWC Pump P114 Kirk key interlock link pin and inspect link pins on all other SWC pumps
- Remove and replace SWC Pump 112 motor for overhaul
- Repair Fire Pump P221 stuffing boxes
- Replace Valve 2/3PSV5657, Fire Pump 221 minimum flow valve

Unit 3

- Repair Valve 3PV0201B, Unit 3 letdown back pressure control valve
- Repair SWC pump bearing temperature indicator for Pump P113

4.1 SWC Pump 2P114 Kirk Key Interlock Improperly Reassembled

On March 6, 1994, while swapping SWC pumps, operators in Unit 2 discovered the Kirk key interlock assembly for Train B SWC Pump 2P114 would not prevent the breaker from being racked in because the Kirk key link pin was incorrectly installed.

As stated in the Updated Final Safety Analysis Report, Section 9.2.1.2.3.3, the design function of the Kirk key interlock is to prevent loading two SWC pumps on the same bus at the same time (to prevent overloading the bus during emergency conditions). Review of component drawings of the Kirk key interlock revealed that this function is accomplished both mechanically and electrically. Mechanically, the Kirk key interlock, when deactivated, prevents an SWC pump breaker from being racked in via interference caused by a Kirk key interlock link pin against the Kirk key interlock plunger. Electrically, the Kirk key interlock, when deactivated, removes power from the breaker control circuit. Operators normally control the coordination of the pump breakers on the bus in accordance with procedures.

The as-found condition and immediate corrective actions were documented in Nonconformance Report (NCR) 94030010. In accordance with Maintenance Order (MO) 94030365, the Kirk key link pin was subsequently installed correctly, and all other Kirk key interlocks were inspected to assure they had been reassembled correctly. No other deficiencies were noted during those inspections.

The inspector reviewed the maintenance documentation for maintenance associated with the Kirk key interlock assembly for the breaker cubicle for SWC Pump 2P114. During the Unit 3 Cycle 7 refueling outage, the motor for the SWC pump was replaced. To determine the correct orientation of the motor power cables, electricians temporarily installed the cables to the motor and momentarily provided power to the motor to check for proper rotation. Prior to connecting the power cables, electricians were required to temporarily reposition the Kirk key link pin so that a safety device (ground truck) could be installed in the breaker cubicle to provide electrical protection. The link pin was required to be repositioned to its original configuration after removing the ground truck from the cubicle. Maintenance records documenting the work performed, which were signed and independently verified by a second qualification individual, recorded the temporary positioning and restoration of the link pin for two separate occurrences. However, the as-found position of the link pin on March 6, 1994, indicated that the restoration of the link pin had not been properly completed in accordance with procedural requirements.

Guidance for the removal and restoration of the link pin was contained in Procedure SO123-I-1.28, TCN 2-1, "Grounding Low And High Voltage Power Systems." During maintenance activities to restore the Kirk key interlock assembly, the licensee identified that Step 6.5.3, which required reinstallation of the link pin, included a partial picture of the Kirk key interlock assembly displaying the position of the link pin with the words written underneath "Kirk Key Removed," which could have been misinterpreted. The inspector noted that, at the time Maintenance personnel were working on the Kirk key interlock assembly (during the outage), the Kirk key had been removed and installed in the other SWC pump Kirk key interlock assembly by Operations. The position of the link pin shown in the picture with the words "Kirk Key Removed" underneath it was such that the breaker could be racked in without the link pin interfering with the Kirk key interlock plunger. The inspector considered that the incorrect assembly of the link pin as found on March 6, 1994, could have been because Step 6.5.3 included a picture which provided confusing and possibly incorrect guidance to restore the link pin.

The inspector considered the safety significance of this incident to be low based on the following: the SWC pump Operating Procedure SO23-2-8, TCN 12-19, "Saltwater Cooling System Operation," provided guidance to operators to verify that each train had one SWC pump in standby with its 4kV breaker racked out, with direct current control power off, the Kirk key removed, and the bearing seal water valve closed. The inspector considered that, given the procedural guidance, it would be unlikely that operators would knowingly attempt to load two SWC pumps onto the same bus at the same time. More importantly, the inspector noted that the Kirk key interlock assembly prevented loading two SWC pumps onto the same bus at the same time via two mechanisms, mechanical (link pin) and electrical interlock (interlock removed power from the breaker control circuitry). The electrical interlock remained operable and was capable of performing its intended function.

The licensee performed a Maintenance Division evaluation to determine the cause of the incorrect assembly of the link pin and to recommend corrective actions. The inspector reviewed the completed evaluation and noted that the root cause of the incident was not identified (in part because the personnel who performed the maintenance activity were not interviewed). In addition, the picture contained in Step 6.5.3 of SOI 23-I-1.28 was not listed as a possible contributing factor to the incorrect reassembly of the Kirk key interlock assembly. The Maintenance Manager stated that additional attempts would be made to contact individuals responsible for performing the activities in question to determine whether or not additional corrective actions were appropriate. The inspector considered that the corrective actions recommended in the evaluation, which included revising the procedure to provide clearer guidance, were adequate, based on the current evaluation.

The inspector concluded that the inadequate procedural guidance in Procedure SO123-I-1.28 was a violation of 10 CFR Part 50, Appendix B, Criterion V. The licensee-identified violation is not being cited because the criteria specified in Section VII.B.(2) of the Enforcement Policy were satisfied.

4.2 Lost MO for SWC Pump 2P112

In December 1993, the inspector requested MO 9305174001 (uncouple and remove/replace SWC pump 3P112 motor) and was informed that the MO had been lost during a previous NRC inspection in 1993.

The inspector noted that Station Procedure SO123-I-1.3, "Maintenance Documentation," Step 6.3.1, required Maintenance Department supervision to initiate actions required for closure and or acceptance of lost maintenance work records. In addition, Step 6.3.2 required maintenance supervision to determine whether work should be reperformed or the documentation reconstructed based on component history, value of lost data, and equipment performance. Procedures used to perform the work were reviewed as part of the evaluation to determine the significance of activities performed. The inspector noted that there were no time requirements or deadlines within which to perform this activity.

The inspector reviewed return-to-service documentation, which included a pump inservice test, and verified that the results were satisfactory. In addition, the inspector discussed the past component performance with the system engineer. The system engineer informed the inspector that the pump had been performing satisfactorily during inservice surveillance testing. However, the system engineer was not aware that the MO had been lost. The inspector considered that in this case, the significance of the lost maintenance documentation was low because the pump had been tested following maintenance and had been operating satisfactorily for a significant period.

The inspector was concerned that the licensee did not have the necessary controls to assure lost maintenance documentation was tracked so that it would be reconstituted. However, the inspector noted that, through the routine process of closing out MOs, supervisory review of documentation was required prior to revising inprocess documentation from Category 70, "work in progress," to Category 86, "history." As a result, the inspector considered that the licensee did have controls in place, although indirect, to note documentation of lost MOs.

4.3 Charging Pump 3P192 Reassembly

On March 21, 1994, the inspector observed procedural and performance discrepancies during the retorquing of nuts on Unit 3 Charging Pump 3P192 following repacking of the plungers. The maintenance was performed per MO 93120196 and Maintenance Procedure SO23-I-8.85, TCN 2-3, "Pumps - Charging Pump and Gear Reducer Routine Maintenance."

Steps 6.3.2.1 through 6.3.2.17 of the procedure directed the packing installation and cylinder assembly for each of the three plungers, and Step 6.3.2.18 directed repeating the previous steps for the other plungers. However, various steps required documentation of data and verification that acceptance criteria were met, but only one place per step was provided for the required "performed by" signature. The steps were only signed once, indicating completion of the step for all three cylinders. In fact, the steps were generally performed on all three cylinders in parallel. The licensee stated that, when the mechanics got to Step 6.3.2.18, directing performance of the sequence for the other cylinders, they mentally determined that the steps had already been performed, and viewed Step 6.3.2.18 as redundant.

Additionally, the inspector noted that Step 6.3.2.17 (final torque pass) was performed prior to documenting the data and signing the performance step for the previous step (initial torque pass).

Maintenance Procedure SO123-I-1.7, "Maintenance Order Preparation, Use, and Scheduling," TCN 4-13, Step 6.15.1.2.1, states that "work packages, including maintenance orders and procedures, must be followed in procedural compliance, subject to the following exceptions . . ." The exceptions listed were not satisfied in this case.

The inspector concluded that the mechanics performed the torquing in a technically adequate manner, but that poor structure of relevant steps in Procedure SO23-I-8.85 resulted in performance of the steps in other than the intended sequence. Additionally, the mechanics failed to sign Step 6.3.2.16 before performing subsequent steps, contrary to Procedure SO123-I-1.7. This is a violation of Technical Specification (TS) 6.8.1.

The licensee acknowledged the inspector's conclusions and agreed to modify the procedure to clarify the sequence of performance. Additionally, the licensee counseled the mechanics regarding the missed sign-off. The inspector concluded that the corrective actions were appropriate. The violation of the failure to follow procedures on the signing off of work steps was of nonsafety significance and is not being cited because the criteria specified in Section VII.B.(1) of the Enforcement Policy were satisfied.

4.4 Failure tc Consider Backpressure in Relief Valve Lift Setpoint

The inspector observed the licensee replace Valve 2/3 PSV5657, a nonsafety-related discharge relief valve for diesel-driven Fire Pump P221. This relief valve relieved to a piping header that also received water from the miniflow of the fire water jockey pumps and the relief flow of the two motor-driven fire pumps. Valve 2/3 PSV5657 provided the minimum flow path for Fire Pump P221.

The inspector noted that water continually flowed from the discharge piping of the relief valve when the licensee replaced the old relief valve with a new relief valve. The water flow indicated a possible pressure source which could affect the relief valve setpoint. The inspector reviewed MO 94020376 and the copy of Procedure SO23-I-8.88, TCN 2-3, "Valves - Cold Bench Testing and Calibration of SR and NSR Safety Relief Valves," that was used for this replacement. Although Step 6.7.12 of the procedure directed the operator to subtract design back pressure from design set pressure to calculate the set pressure, the inspector noted that no back pressure was used and the set pressure of 145 psig was used directly. The inspector noted that one of the fire main jockey pumps continually operated to maintain fire main pressure and, consequently, continually flowed to the common header. The inspector considered that this continual miniflow would fill the common header and the piping from the common header to the top of the service water tanks. Thus, Valve 2/3 PSV 5657 would be relieving against approximately 40 feet of water (approximately 10 psig of backpressure). The inspector was concerned that this would cause the valve not to provide miniflow until pump discharge pressure reached 155 psig (145 psig plus 10 psig backpressure). As the pump shutoff head was approximately 150 psig, the pump may have been damaged due to insufficient minimum flow while running at the shutoff head, if it was operated with no loads on the fire main system.

The licensee acknowledged this concern and agreed to consider backpressure in planned Site Problem Reports concerning all three discharge minimum flow valves for the fire water pumps. The inspector considered this response adequate and will continue to monitor the proper setting of relief valves in future maintenance observations.

4.5 Conclusions

The inspectors concluded that licensee Maintenance Procedure SO123-I-1.28, TCN 2-1, was inadequate and contributed to the improper installation of a Kirk key interlock assembly. The violation of 10 CFR Part 50, Appendix B, Criterion V, was not cited.

The inspectors concluded that, although the Maintenance Division evaluation of the improper Kirk key installation identified procedural weaknesses and recommended additional procedural guidance, the evaluation was weak in that the licensee did not question the contractor electricians who performed the maintenance activity.

The inspectors concluded that the licensee's program for reconstitution of lost maintenance documentation was weak in that the program lacked any timeliness guidelines or periodic reviews. The licensee's program did loosely track lost documentation only by preventing final document closure without first completing a document review.

The inspectors identified a noncited violation when mechanics failed to record data or sign off a procedural step before proceeding to the subsequent step during reassembly of a charging pump. The inspectors concluded that Maintenance Procedure SO23-I-8.85, TCN 2-3, was weak in that it provided confusing direction as to whether charging pump cylinders should be reassembled in parallel or sequentially. Neither of the errors had technical significance.

The inspector concluded that the licensee failed to consider the effects of backpressure in determining the relief setpoint for a firewater pump discharge relief valve.

5 EMERGENCY PLAN QUARTERLY EXERCISE (82301)

On March 30, 1994, the inspectors observed the licensee's quarterly emergency plan exercise. In addition to monitoring the general conduct of the exercise, the inspectors observed the personnel accountability and site evacuation that were performed during the exercise. Communications in the Technical Support Center (TSC) during the exercise were good. The Emergency Director kept the TSC well informed of plant status and mitigation activities. During the loss of offsite power, the exercise simulation included actually deenergizing lighting panels supplying illumination to the TSC. Flashlights and battery-powered lanterns were quickly distributed and provided adequate lighting for continued TSC operation.

The accountability portion of the exercise was accomplished using the computer-based Protected Area Personnel Accountability system, which is not yet implemented as the official accountability system. The system was being tested during the exercise, and was operated without formal, approved, procedures. The accountability involved transferring information between the TSC, Operations Support Center, and Central Alarm Station (CAS). The CAS Supervisor received disks of information from the other two locations and processed the information in the security computer, generating a list of discrepancies. This information was then transmitted electronically to the TSC accountability computer. The inspector noted that the CAS Supervisor used instructions on a piece of paper he had in his pocket to tell him how to transmit the data electronically to the TSC. The inspector then determined from the CAS Supervisor that the instructions were not yet contained in any procedure, and that the interim instructions had been E-mailed to him the previous day. Because the task appeared to be complex and infrequently performed, the inspector determined that the instructions should be formalized before the system is deemed operable. The inspectors concluded that accountability was satisfactorily performed with the unofficial system.

The inspectors observed the site evacuation. The evacuation appeared to be very orderly and efficiently accomplished. Because of the wind direction utilized in the exercise scenario, the evacuation route utilized beach roads instead of the normal site access road. The inspector concluded that the exercise adequately demonstrated site evacuation capability.

6 SIMULATOR OBSERVATIONS (41500)

6.1 March 28, 1994

On March 28, the inspector observed training provided to an operating crew in the plant-referenced simulator by licensee training instructors. Three scenarios were run and the trainers, as well as the crew itself, critiqued operator actions after each scenario was completed. The inspector noted the following points, which had not been commented on by training instructors during the critiques:

- The "Procedures in Use" file was not accurate for plant conditions, causing initial confusion for the operating crew during the first scenario.

- Some weak communications were observed between the Control Room Supervisor and the Control Operator. These weak communications (lack of repeat-back for common understanding) did not result in any control board misoperation.

- One control board misoperation, attempting to shut safety injection (SI) isolation valves, with an SI signal present and the valves not overridden, was observed. The operator realized his mistake and overrode the SI signal and then shut the valves.

- One control room supervisor did not announce to "regard annunciators" after the Emergency Operating Procedures were entered. The facility trainers informed the inspector that it was management's expectation that this announcement be given.

The licensee trainers agreed with the inspector that the "Procedures in Use" file should have been current and that the comments above could have been used as points to enhance training. The trainers said they were not mentioned due to oversight. The inspector considered the observations minor in nature and concluded overall that the training was adequate and beneficial to the operating crew.

During a review of a portion of the Emergency Operating Instructions (EOIs) used during the scenarios, the inspector noted one deviation from the owners' group guidance for the EOIs that was neither identified nor justified in the licensee's deviation document. This was contrary to the methodology presented in NUREG 0899, "Guidelines for the Preparation of Emergency Operating Procedures," which stated that all deviations from the owners' group guidance should be identified and justified. The inspector noted that Step 3 of Procedure SO23-12-1, Revision 10, "Standard Post Trip Actions," deviated from the equivalent step of CEN-152, Revision 3, the Combustion Engineering Owners' Group guidance. This was not identified in Procedure SO23-14-1, TCN 0-1, "Standard Post Trip Actions Bases and Deviations Justification." The deviation was using core element assembly calculators in addition to rod bottom lights to verify all control rods fully inserted after a reactor trip. The CEN-152 guidance was to use rod bottom lights only. The licensee presented the inspector with a justification for this deviation and agreed to incorporate the justification into a planned upcoming revision of the deviation document. The inspector considered this adequate.

6.2 April 5, 1994

On April 5, the inspector observed a crew during simulator training. During the first portion of the session, involving routine plant maneuvers and minor malfunctions, the instructors effectively coached the crew in areas of weakness. The crew closely followed alarm response procedures and normal operating procedures. Several minor procedural deficiencies were identified by the crew and the instructors, which were documented for routine referral to the procedures group. The inspector noted that communications during this portion of the scenario were casual, though the shift superintendent increased attention to communications as the session continued. The session ended with a major event involving loss of offsite power and the failure of an emergency diesel to load. The crew's communications and command and control during this event were notably more deliberate and formal than before the event. Use of procedures appeared to be good, and the crew successfully mitigated the event until termination. The short postsession debrief highlighted the need for better communications.

The inspector noted that this was the second day of training for that crew during this requalification cycle. The inspector concluded that the training was effective in enhancing operator knowledge of the subject material and of communication needs and that procedure use and command and control were adequate.

6.3 Conclusions

The inspectors concluded that, while the training appeared to be generally effective, simulator instructors should be more critical of minor communication and performance deficiencies. Additionally, a deviation between an EOI and the owners' group guidance was identified that was not in the licensee's deviation document.

7 POST FIRE SAFE SHUTDOWN CAPABILITY (64150)

In order to assess the licensee's ability to safely shut down and cool down the reactors in the event of a fire, the inspector conducted a desktop review of procedures, walked down selected portions of procedures in the plant with licensee operators, and reviewed aspects of the licensee's emergency lighting system. Results of these inspection activities are described below. Overall, the inspector found the licensee's procedures and equipment adequate, with the exceptions noted below.

7.1 Desktop Review

The inspector reviewed portions of Procedures S023-13-21, TCN 1-10, "Fire," and S023-13-2, TCN 2-17, "Shutdown From Outside the Control Room." The inspector noted the following:

- The correction curve for pressurizer level Instrument L-103 in the "Fire" procedure did not agree with the correction curve for the same instrument in the "Shutdown from Outside the Control Room" procedure. The instrument required a correction curve because it was calibrated at cold shutdown conditions but could be used at hot, pressurized, conditions in the procedures. The licensee agreed to correct this in TCN 1-11 of the "Fire" procedure.

- The "Fire" procedure did not caution the operators that Instrument L-103 was not qualified for use after a seismic event, as did the "Shutdown from Outside the Control Room" procedure. The licensee agreed to correct this in TCN 1-11 of the "Fire" procedure.

- The inspector considered that Attachment 8 to the "Fire" procedure was not clear because the procedure did not contain a step to shut down the reactor. The attachment assumed that the reactor had been shut down. The licensee agreed to correct this in TCN 1-11 of the "Fire" procedure.

- Tank level figures for condensate storage tanks and boric acid tanks in Attachment 8 of the "Fire" procedure did not contain precautions about using tank level indications, with no flow past the detector, as that mentioned in the "Shutdown from Outside the Control Room" procedure. The level for these tanks was determined using pump suction pressure gauges and no flow was required for an accurate measurement. The licensee agreed to correct this in TCN 1-11 of the "Fire" procedure.

- Caution statements in "Shutdown from Outside the Control Room" seemed contradictory as the operator was cautioned initially (in Step 2, "Performance Guidelines," of several attachments) to not delay actions for Health Physics, Security, or any other concerns. Yet, prior to entry to tanks or vaults, there was a caution (i.e., Unit 2 primary plant equipment operator duties, after Step 4.6.1) that "the space shall be tested for oxygen and toxic gases immediately prior to entry." The licensee generated a procedure change request to clarify this point, the intent being to ensure the spaces are habitable prior to entry.

- When monitoring steam generator level at the essential plant parameters monitor panel, the "Shutdown from Outside the Control Room" procedure used a graph to compensate steam generator level for temperature, but the "Fire" procedure directly used indicated level. This was for the same level indication. The licensee agreed to correct this in TCN 1-11 of the "Fire" procedure.

- For a fire, the "Shutdown from Outside the Control Room" procedure prohibited monitoring pressurizer level or steam generator level at the evacuation shutdown panel, but the "Fire" procedure allowed monitoring from any location (Step 6.0 of Attachment 6 to "Fire"). The licensee agreed to direct usage of Panel L411 in TCN 1-11 of the "Fire" procedure.

The inspector reviewed the corrective actions described above and was informed that, based on the inspector's questions, TCN 1-11 of the "Fire" procedure was revised and under final review by the licensee at the end of the report period. The inspector concluded that these deficiencies did not render the procedure inadequate, in that the procedures could be successfully used as written, based on the inspector's limited review. However, based on the number of discrepancies identified, the inspector concluded that additional licensee review of the procedures appeared warranted. The licensee has initiated a review of these procedures.

7.2 <u>Procedure Walkdowns</u>

The inspector walked down Attachments 2, 5, and 21 of the "Shutdown From Outside the Control Room" procedure with licensee operators. The walkdowns were of the control room supervisor and the control operator duties in the event the control room had to be evacuated. The inspector noted the following:

- New 10 CFR Part 20 dose terminology had not been incorporated into these attachments.

- A lever necessary for local, manual operation of the non-Class 1E pressurizer heater breakers was not readily available for use at the essential plant parameters monitor panel.

The licensee agreed to evaluate incorporating the new terminology and evaluate making the lever available.

7.3 <u>Emergency Lighting</u>

The inspector walked down portions of the emergency lighting installed in the Unit 3 auxiliary feedwater (AFW), main steam isolation valve and EDG areas. The inspector, accompanied by a licensee fire protection specialist, also spot checked emergency lights for operability in these areas.

The inspector concluded that five emergency lights in these areas (of a total of about 40) were not oriented as described in the emergency lighting scheme presented in the "Fire Hazards Analysis" Unit 3 Lighting section. The inspector also concluded that these five lights were not oriented per Procedure SO23-XIII-53, TCN 0-3, Attachment 1, "Surveillance Data Record Form, Units 2 and 3 Individual Battery Pack Emergency Lights." The inspector walked down these areas on Monday, April 4, 1994, and noted that the surveillance had been completed on Sunday, April 3, 1994. These Unit 3 lights were designated as: 3XC2L8E07 (main steam isolation valve area), 3XD1L8E10 (EDG area), 3XD1LE05 (EDG area), 3XJ1L8E33 (AFW area), and 3XJ1L8E25 (AFW area). The inspector noted that the surveillance record form contained a table listing each emergency light and the targets for the left and right beams of the light. These targets were generally emergency routes the operators might use or specific pieces of equipment. In the five cases listed above, the inspector considered that each light was oriented out-of-line with the designated target to not optimally illuminate the designated target. One example was Unit 3 Atmospheric Dump Valve (ADV) 3HV8421. Light 3XC2L8E07's right beam was to illuminate this ADV; however, the inspector found the beam oriented generally towards the center of the space, not directly toward the corner where the ADV was installed.

In response to inspector questioning, the licensee repositioned the beams of the five lights, pointing them in the direction the surveillance procedure indicated.

The inspector considered that the misorientation of the five lights, when the surveillance procedure indicated that they were oriented properly, was a failure to implement Procedure SO23-XIII-53, TCN 0-3, "Quarterly Emergency Lighting System Inspection." The inspector noted that Unit 3 TS 6.8.1 required that written procedures be implemented in the area of surveillances for Fire Protection System Functional Tests and considered the failure to implement this procedure a violation.

The licensee agreed to take the following actions:

- Initiate a division investigation
- Perform a surveillance of a high percentage of emergency lights to ensure proper illumination of subject targets
- Retrain fire inspectors who perform this surveillance, and evaluate the procedure for enhancements
- Increase surveillance periodicity in areas, such as the EDG areas, that could have high vibration
- Evaluate the design of the holding mechanism for the beams of the emergency lights if it is determined that the beams may be slipping out of the intended direction

The inspector considered these corrective actions adequate. Consequently, this violation is not being cited based on the low safety significance of the conditions identified and that the criteria of Section VII.B.(1) of the Enforcement Policy were met.

8 FOLLOWUP (92701)

8.1 (Closed) Followup Item 361/9319-04: Unit 2 Mode Status while Defueled

This item involved the mode status of Unit 2 with all fuel assemblies removed from the reactor vessel and stored in the spent fuel pool. During the Unit 2 Cycle 7 refueling outage the licensee had commenced core reload, from a completely defueled condition, with one train of the control room emergency air cleanup system inoperable. TS 3.7.5 required that both trains of the control room emergency air cleanup system be operable in all modes, and the licensee was required to enter ACTION steps if this was not the case. The licensee was complying with these ACTION steps. The licensee discussed this matter with NRC personnel prior to reloading fuel into the reactor. Based on the discussions, clarification was requested from the Office of Nuclear Reactor Regulation of how to consider modes and mode changes when a licensee defuels the reactor during outages.

In March 1994, the Nuclear Reactor Regulation concluded that "OPERATIONAL MODES" are defined in the Definitions section of the TS, and MODE 6, "REFUELING" is defined as "Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed." When there is no fuel in the reactor vessel, the unit is not in Mode 6. Both acts of removing the last fuel bundle from the reactor vessel and loading the first fuel bundle back into the reactor vessel constitute a mode change. Therefore, the provisions of TS 3.0.4 and 4.0.4 are applicable for entry into an OPERATIONAL MODE, including MODE 6, or other specified condition (such as defueled condition), whether the entry is from another OPERATIONAL MODE or any condition.

Based on the information as stated above, the licensee committed to revise pertinent station orders and TS interpretations, prior to the next refueling outage, to consider changing from defueled to Mode 6 and Mode 6 to defueled a mode change. The inspector found this response adequate.

8.2 (Closed) Followup Item 361/9326-01: Reactor Coolant Pump (RCP) Speed Pulse Shaper

This item resulted from inspection activities associated with RCP speed pulse shapers, during which the inspector noted that, as of August 30, 1993, 45 percent of a total of 1214 outstanding NCR disposition steps were beyond their projected completion date. Among these was a disposition step to change the acceptance criteria for RCP speed sensing pulse width to a larger band as a result of repeated failure of a narrower acceptance criteria.

The inspector reviewed a report of active NCRs not closed, as provided by the licensee, and dated March 11, 1994. The inspector noted that 28 percent of the 1100 outstanding NCR disposition steps were beyond their projected completion date. The inspector noted that this was a decrease in the total number of outstanding disposition steps, and a decrease in the percent that were overdue, from the status 6 months ago. The inspector considered this decrease a positive sign.

The inspector sampled 15 NCRs with outstanding disposition steps for safety significance. The inspector concluded that, of these 15 sampled, it was potentially safety significant that one NCR with overdue disposition steps was not completed. This is described below. The remainder of the NCR dispositions appeared adequate to the inspector.

8.2.1 Fire Dampers

NCR 92050027, Revision 0, was written on May 12, 1992, because Fire Damper SAAC50310D4001FD failed to close completely during a drop test surveillance as prescribed by Procedure S023-XIII-57, TCN 3-2, "18-Month Fire-Rated Assembly Inspection." During the surveillance test, the damper failed to close with airflow through the ventilation ducting. The inspector noted that a total of 91 NCR disposition steps, some overdue, related to fire dampers were pending. Fire dampers are installed in ventilation ducting and are intended to close completely when fusible links that hold the dampers open melt from the heat of a fire. This prevents the spread of fire from space to space through the ventilation ducting. The inspector noted that some of the 91 disposition steps involved fire dampers leading into spaces with equipment necessary for safe shutdown of Units 2 or 3. Steps 4 and 5 of the above NCR were approximately 1 year overdue and were intended to revise the "Fire" and "Shutdown From Outside the Control Room" procedures, directing the operators to secure ventilation to the space this damper led into. This was the method the licensee had chosen to ensure that the damper would close in the event of a fire.

The inspector reviewed applicable documentation and procedures, and interviewed licensee personnel. Regarding these fire dampers, the inspector determined the following chronology:

- November 1984: Ruskin Manufacturing issued a 10 CFR Part 21 report stating that some of its fire dampers might not close under air flow conditions.

- June 1988: The NRC issued Revision 1 to a Safety Evaluation Report in which the licensee committed to testing 10 percent of all installed fire dampers each 18 months, until all dampers were tested, under ambient air flow conditions. The concern was that the dampers might not shut completely under the differential pressure caused by air flow, as they were qualified to shut only with no air flow. Although the licensee only had two Ruskin type dampers, the other dampers were also subject to the same concern.

- June 1989: The NRC issued Information Notice (IN) 89-52. This IN alerted licensees that curtain-type fire dampers might not shut under air flow conditions, and listed three options that licensees have taken to address the issue: (1) type-test dampers under worst case air flow conditions, (2) test all fire dampers, or (3) administratively shut down ventilation to an area upon confirmation of a fire.

- May 1991: The licensee issued document 90100, "Fire Damper Study," Revision 0. The damper study identified dampers that were required to close under air flow conditions and the operator actions required to secure ventilation to the remaining dampers.

- May 1992: NCR 92050027, as described above, was issued because the damper was tested as a part of the 10 percent sample. Other NCRs were issued as dampers failed this surveillance test both before and after this particular damper.

- January 1993: The licensee issued Revision 1 to the "Fire Damper Study."

- August 1993: The licensee issued Revision 2 to the "Fire Damper Study." The study identified those dampers required to close under air flow conditions as well as those dampers for which operators could secure air flow. The study concluded that 50 dampers could not be assured to close when subjected to a fire because ventilation should not be secured. The remaining dampers (approximately 325, including those in Unit 1) could be assured to close during a fire, provided that specified heating, ventilation, and air conditioning units associated with each damper were deenergized.

- April 1994: The inspector reviewed Abnormal Operating Instruction SO23-13-21, TCN 1-10, "Fire," and the "Fire Hazards Analysis," Revision 9, and found that the procedures had not been revised to reflect which dampers required operator action to ensure they functioned properly. The licensee informed the inspector that the "Fire" abnormal operating instruction would be revised during April 1994 and that action had been planned to identify a plan to test the dampers that operators cannot secure ventilation through under worst case air flow conditions.

Based on the above the inspector concluded the following:

The licensee had developed a plan and was progressing towards corrective action in response to IN 89-52. The licensee planned to revise procedures to secure ventilation through some dampers and to test the remaining dampers under worst case air flow conditions and make modifications as necessary to ensure that they closed. The inspector considered that this plan appeared prudent. However, the inspector also noted that almost 5 years had passed since the IN was issued and that the licensee had still not revised procedures or tested all dampers to ensure they would shut under air flow conditions. While the licensee had tested a majority of the dampers, the inspector was concerned that 5 years was an excessive amount of time to still not have the issue fully resolved. The licensee informed the inspector that the revision based on the inspector's questions on the "Fire" procedure was completed and under final review at the end of this report period. The inspector considered this adequate.

8.3 <u>(Closed) Unresolved Item 361/9331-03: Emergency Cooling Unit ME399 Component Cooling Water (CCW) Valve 3HV6371 - Unit 3</u>

In January 1993, the circuit breaker for Valve 3VH6371 tripped open while operators stroked the valve in the open direction (its safety function direction). The valve has been stroked to balance CCW flow. As a result, the valve was declared inoperable. In accordance with TS 3.6.3, "Containment Isolation Valves," the valve was secured in its safety function position (open).

The valve is one of four containment emergency cooling unit CCW return valves. The valve is a WKM, 8-inch, split-disc, wedge-gate valve. Two containment emergency cooling units comprise one train of containment emergency cooling. The inspector noted that the Updated Final Safety Analysis Report (Chapter 6, Page 6.2-5) specified that the design basis response to loss of coolant accident or main steam line break required two trains of containment spray, or two trains of containment emergency cooling, or one train of containment spray and one train of emergency cooling were required.

In November 1993, during the Unit 3 Cycle 7 refueling outage, the valve was disassembled, and the gate disc, segment disc, gate skirt, and segment skirt were found to be incorrectly installed (documented in NCR 93110055). The licensee subsequently determined that the incorrect assembly of the upstream skirt ultimately caused the failure of the valve to stroke in January 1993.

<u>Signature Anomaly</u>

Diagnostic thrust signatures taken for Valve 3HV6371, during the Cycle 6 refueling outage in March 1992, indicated abnormally high running thrust throughout the valve's stroke. The condition was not observed in the other seven similar valves tested during the outage. Maintenance records which documented the testing on the valve noted the presence of the high running thrust signature. The licensee's initial evaluation was that the valve stem was bent; however, upon further investigation, no bent stem was found and the signature continued to be abnormal as compared to similar valves. The licensee did not consider the anomaly to affect valve operability valve because the valve had a history of higher than normal thrust signatures.

To address the high running thrust signature, the licensee initiated an MO to replace the actuator. However, the MO was rejected in September 1992 because the actuator had been replaced in 1988 and, therefore, it was thought that the actuator was not the cause of the problem. A second MO was subsequently rejected, and a third MO was initiated to investigate the problem during the Unit 3 Cycle 7 refueling outage (scheduled to start in October 1993). The purpose of the third MO was to inspect the valve internals for the cause of the observed signature abnormalities. In January 1993, while stroking the valve for CCW flow balancing, the motor breaker for Valve 3HV6371 tripped open on overload. The breaker tripped when the valve was attempting to go to its safety function direction due to degrading valve performance caused by the improper reassembly of the valve skirts.

After the damaged valve components were replaced and reassembled properly, the valve signature anomaly was eliminated. This clearly indicated that, had a thorough evaluation of the abnormal trace and aggressive corrective actions been performed, the misassembly problem could have been identified earlier and corrected before it eventually caused the valve to fail.

This failure to resolve the observed abnormalities with Generic Letter (GL) 89-10 test data for Valve 3HV6371, which indicated the condition that was determined to ultimately cause the valve's failure to stroke in January 1993, is a an example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" (Violation 362/9408-01).

In response to questions from previous NRC inspections, the licensee completed an evaluation of the events surrounding the failure of Valve 3HV6371, which was submitted to the NRC on March 3, 1994 (letter from R. Rosenblum, Vice President, Engineering and Technical Services). The licensee acknowledged that its corrective actions associated with the evaluation of diagnostic signatures for Valve 3HV6371 were not aggressive. The licensee concluded that the issue would have been successfully resolved had it occurred under their current program, which incorporated changes to improve the evaluation and corrective actions for significant anomalies.

Subsequent to the Cycle 6 GL 89-10 testing in March 1992, the licensee developed Station Procedure S023-V-3.50 to provide a formalized program to analyze motor-operated valve data collected during static and dynamic testing to evaluate capability, operability, and functional margin. The inspector reviewed Procedure S023-V-3.50, TCN 0-2, and considered that the procedure had controls to evaluate unusual qualitative characteristics observed in motor-operated valve diagnostic signatures. The inspector concluded that the licensee's corrective actions were adequate. Therefore, the inspector considered that no further response was required. In addition, the licensee's motor-operated valve program was reviewed by the NRC staff and findings documented in NRC Inspection Report 50-528/94-15; 50-529/94-15; 50-530/94-15.

The licensee submitted licensee event report (LER) 93-005-01 to discuss the circumstances surrounding the misassembly of Valve 3HV6371 as well as safety significance of the event. The licensee concluded that the valve's failure to stroke in January 1993 was caused by incorrect reassembly of the upstream skirt. The licensee concluded that the valve had been inoperable in excess of the out of service time limits of TS. As a result of discovering the condition of Valve 3HV6371, motor-operated valve testing signatures for other WKM valves were reviewed, and those valves were considered to be correctly reassembled. The licensee concluded that the safety significance of the misassembly of Valve 3HV6371 was low because there were sufficient containment cooling components operable to ensure containment pressure and temperature design limits were maintained. The inspector reviewed the LER and concluded that the evaluation was adequate.

Inadequate Procedure

The licensee performed a Maintenance Division investigation to identify the root cause for the misassembled valve and to recommend corrective actions. In general, the inspector considered that the investigation was thorough and that the corrective actions recommended appeared to address the root cause. The inspector noted that a contributing factor to the valve's misassembly was that guidance for installation of the skirts had not been properly incorporated from the valve's vendor manual, SO23-I-507-5-1-342 (WKM 8" Wedge Gate Valve). Specifically, the vendor manual described that the segment skirt needed to be installed against the segment disc and likewise for the gate. The inspector reviewed Station Procedure SO123-I-6.75 TCN 0-2, "Valve, WKM Model D-2 Gate Valve," which was used to reassemble the valve in 1988 and noted that the procedure did not contain guidance to insure the skirts were properly assembled. In addition, the inspector noted that the Maintenance Division evaluation did not identify that the specific guidance for installation of the skirts which was not included in Procedure SO123-I-6.75, TCN 0-2, may have contributed to the misassembly of the valve.

The failure to include appropriate guidance in Procedure SO123-I-6.75, TCN 0-2, to effect the proper installation of the valve skirts is a violation of 10 CFR Part 50, Appendix B, Criterion V. However, because Procedure SO123-I-6.75 had been previously revised in 1990, and was revised further based on lessons learned from this incident, the inspector concluded that the licensee's corrective actions were adequate. Therefore, this violation is not being cited because the requirements of Section VII.B.(1) of the Enforcement Policy were satisfied.

8.4 (Closed) Unresolved Item 361/9331-04: Use of Controlotron for Controlled Bleedoff (CBO) Flow

This open item involved the use of a Controlotron (System 990 Uniflow Universal Clampon Nema Flowmeter) to measure the flow of CBO from a RCP. CBO flow from each RCP seal goes to the volume control tank. The CBO flow path is through a flow detector and then into a common header, exiting containment, and then to the volume control tank. When one or more of the CBO flow indications is out of service, the licensee uses a Controlotron flow indicator installed on the common line outside containment to measure flow. The licensee uses this CBO flow as a part of identified reactor coolant system leakage during performance of the Water Inventory Balance surveillance. The inspector had questioned the accuracy of the Controlotron used in this application.

The inspector reviewed the vendor technical manual for the Controlotron (dated May 1990), the procedure for the water inventory balance (SO23-3-3.37, TCN 9-20, "Reactor Coolant System Water Inventory Balance"), past TCNs for this procedure, the MOs used to install the Controlotron, water inventory balance data for Unit 2 for August and September 1993, and appropriate isometric drawings for the location the Controlotron. The inspector visually inspected this area (Penetration 7) and interviewed appropriate licensee personnel. The inspector also reviewed the licensee's SONGS Test Equipment Management System (STEMS) data base and contacted vendor representatives from the Controlotron Company. The inspector noted the following:

- Unit 2 water inventory balance data showed an average CBO flow of 5.85 gpm using installed instrumentation, and an average flow of 7.79 gpm using the Controlotron (an approximate 33 percent increase). No changes to the piping system or RCP seals were made when the Controlotron was in use.

- The vendor technical manual, in Section 7.8.1, discussed accuracy. The accuracy of the instrument was considered usually better than 3 percent (for flowrates above 1 foot per second). However, it was noted that accuracy could deteriorate when pipe diameter to wall thickness ratio fell below 15 to 1 and that this ratio would effect nominal accuracy at values below 10 to 1. The inspector noted that the Controlotron was installed on a 3/4-inch Schedule 160 stainless steel pipe and calculated a pipe diameter to wall thickness ratio of approximately 5 to 1 and a general flowrate of approximately 6.5 feet per second.

- The technical manual also recommended using the smallest transducer allowable for smaller pipe applications.

- MO 93082057000 used to install the Controlotron on Unit 2 during September 1993 listed accuracy as 3 percent, the STEMS data base listed accuracy as per manufacturer. A transducer Series 1 was used during this application. The vendor manual allowed use of a Series 1 or Series 0 transducer for 3/4-inch pipe, the Series 0 being smaller.

- Installed instrumentation for CBO flow had an accuracy of 1 percent.

Based on the above, the inspector concluded the following:

- The accuracy of the Controlotron used to measure CBO flow appeared to be in the range of 3 percent to 33 percent, with the data generally reading higher than actual flow. This was a conservative error, as the identified leakage would tend more toward the TS limit (10 gpm).

- Accuracy listed in some MOs appeared incorrect for the specific application used; the accuracy in the STEMS data base appeared correct.

- The vendor manual appeared to recommend a smaller transducer size than was used.

- A 33 percent accuracy, as compared to a 1 percent accuracy of normal indication, appeared excessive.

The inspector met with the licensee's Operations Manager (acting) who agreed to either improve the methodology of use of the Controlotron to enhance accuracy or to not use the Controlotron to measure CBO flow. The inspector considered this response adequate.

8.5 (Closed) Unresolved Item 362/9331-06: Water in Reactor Cavity to Spent Fuel Pool (SFP)

This item involved the review of the licensee's investigation of the events surrounding the draining of the Unit 3 refueling cavity to the SFP that occurred on October 22, 1993, during core alterations (Cycle 7 refueling outage).

Specifically, the inspector was concerned that corrective actions which were implemented after a similar event on February 8, 1992 (Cycle 6 refueling outage), were not thorough or effective to preclude draining the reactor cavity in October 1993. As a result of the February 8, 1992, event, an evaluation for the root cause and corrective actions was documented in Operations Division Evaluation Report (ODER) 3-92-07A. The corrective actions included revising Station Procedure SO23-1-4.2, "Containment Purge And Recirculation Filtration System," to incorporate guidance, in the event containment purge could not be restarted, to secure sources of air to containment, to vent containment via the personnel hatch equalizing valves, and to secure core alterations to avoid draining the reactor cavity to the SFP.

On October 22, 1993, chemistry technicians requested that Operations remove containment purge stack Radiation Monitor 3RI7828 from service so the technicians could change out the monitor's filter. The changing out of the filter normally involved isolating containment purge for less than 1 hour and was a routine evolution. Removing the radiation monitor from service required that containment purge be isolated until the radiation monitor was returned to service. Operators secured containment purge in accordance with

Procedure SO23-1-4.2, TCN 14-15. Specifically, operators used Attachment 5, Section 2.3, to isolate containment purge. Because corrective actions outlined in the ODER 3-92-07A had not been incorporated into Section 2.3, operators had not initiated actions to terminate air sources to containment, or provide for alternate means to vent containment in a timely manner when they were informed that Radiation Monitor 3RI7828 could not be returned to service. The filter change-out took longer than expected and because pressure increased in containment the level in the reactor cavity was eventually reduced below TS limits. Prior to reaching the TS limit, operators had secured core alterations. However, the sources of air to containment continued to increase the pressurization. Because operators were late in providing an alternate means to vent containment, the refueling cavity level decreased slightly below the TS limit of 23 feet. The refueling cavity level decrease was terminated when operators bypassed interlocks for the containment personnel hatch equalizing valves and vented containment. Water level was restored using a low pressure safety injection pump.

The inspector noted that the corrective actions which were implemented after the February 1992 event were not included in Section 2.3 of Attachment 5. In addition, Section 2.3 contained all necessary guidance to isolate and restore containment purge such that operators did not need to refer to other sections of the procedure. The inspector noted that the corrective actions as specified in ODER 3-92-07A were contained in other sections of Procedure SO23 1-4.2, TCN 14-15. However, the licensee stated that operators had not used the other sections to remove the radiation monitor filter. Based on the review of Procedure SO23-1-4.2, and the actions taken by operators during the second event, the inspector considered that the licensee's corrective actions as outlined in ODER 3-92-07A were not effective in precluding draining the reactor cavity on October 22, 1993.

This failure to effectively implement corrective actions as outlined in ODER 3-92-07A is the second example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action (Violati 362/9408-01).

The inspector considered the significance of the event to be low because the level decrease was small (6 inches) and took several hours to initiate, Operations personnel eventually initiated actions to terminate the sources of air into containment and vent containment, and there were several alternate methods available to operators to restore level throughout the event.

Based on the October 1993 event, the licensee completed another ODER to identify the root cause and recommend corrective actions. The licensee identified the root cause to be a programmatic problem because the procedural requirements for temporarily securing containment purge to perform a filter change-out did not contain the necessary actions should there be a delay in re-initiating containment purge. In addition, the licensee identified that control room alarms associated with the event, such as containment purge valves closed, SFP level high/low, or refueling cavity level high/low, also did not contain the expected actions. The inspector reviewed the licensee's corrective actions which included once again revising Procedure SO23-1-4.2, providing guidance in all sections which may be used to isolate containment purge, and revising applicable alarm response procedures to direct operators back to Procedure S023-1-4.2. In addition, the licensee concluded that improvements to the implementation and verification of ODER corrective actions were warranted and revised the program procedure to incorporate lessons learned. The inspector considered that the ODER was probing and thorough and that licensee's corrective actions were adequate.

9 IN-OFFICE REVIEW OF LICENSEE EVENT REPORTS (90712)

The following LERs were closed based on in-office review:

- 361/93-005, Revisions 0 and 1: Inoperable Containment Isolation Valve
- 361/94-001, Revision 0: Manual ESF Actuation of Toxic Gas Isolation System to Satisfy Technical Specification Action Statement

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

D. Breig, Manager, Station Technical
L. Cash, Maintenance Manager
*P. Champion, Supervisor, Security Compliance
C. Chiu, Manager, Quality Engineering
*C. Couser, Supervisor, Fire Protection
V. Fisher, Assistant Operations Manager
*G. Gibson, Supervisor, Onsite Nuclear Licensing
*R. Giroux, Licensing Engineer, Onsite Nuclear Licensing
*A. Harkness, Control Room Supervisor
*F. Harland, Control Room Supervisor
D. Herbst, Manager, Quality Assurance
*J. Hirsch, Power Generation Manager
*M. Jones, Assistant Plant Superintendent
*R. Joyce, Maintenance Manager, Units 2/3
*P. Knapp, Manager, Health Physics
*R. Krieger, Vice President, Nuclear Generating Station
*W. Marsh, Manager, Nuclear Regulatory Affairs
H. Newton, Manager, Site Support Services
*D. Niebrugge, Station Technical
*G. Plumlee, Lead Engineer, Onsite Nuclear Licensing
H. Ray, Senior Vice President, Power Systems
J. Reeder, Manager, Nuclear Training
J. Reilly, Manager, Nuclear Engineering & Construction
*M. Robinson, Licensing Engineer, Onsite Nuclear Licensing
*R. Rosenblum, Vice President, Engineering & Technical Services
M. Short, Manager, Site Technical Services
*K. Slagle, Manager, Nuclear Oversight
T. Vogt, Plant Superintendent, Units 2/3
R. Waldo, Operations Manager
M. Wharton, Manager, Nuclear Design Engineering
*T. Yackle, Manager, Nuclear Engineering Design Organization, NU/MECH
*W. Zintl, Manager, Station Emergency Preparedness

1.2 Other Personnel

G. Edwards, Site Representative, City of Anaheim
R. Erickson, Site Representative, San Diego Gas and Electric
C. Harris, Site Representative, City of Riverside

1.3 NRC Personnel

*J. Russell, Resident Inspector
*J. Sloan, Senior Resident Inspector
D. Solorio, Resident Inspector

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

*Denotes personnel that attended the exit meeting.

2 EXIT MEETING

An exit meeting was conducted on April 20, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

ACRONYMS

ADV	atmospheric dump valve
AFW	auxiliary feedwater
CAS	central alarm station
CBO	controlled bleedoff
CCW	component cooling water
EDG	emergency diesel generator
EOI	emergency operating instruction
GL	generic letter
IN	information notice
LER	license event report
MO	maintenance order
NCR	nonconformance report
ODER	Operations division evaluation report
RCP	reactor coolant pump
SFP	spent fuel pool
SI	safety injection
STEMS	SONGS [San Onofre Nuclear Generating Station] Test Equipment Management System
SWC	saltwater cooling
TCN	temporary change notice
TS	technical specification
TSC	technical support center