ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-275/95-16
50-323/95-16

Licenses: DPR-80
DPR-82

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1451
P.O. Box 770000
San Francisco, California

Facility Name: Diablo Canyon Nuclear Power Plant, Units 1 and 2

Inspection At: Diablo Canyon Site, San Luis Obispo County, California

Inspection Conducted: October 29, 1995 through December 9, 1995

Inspectors: J. Dixon-Herrity, Acting Senior Resident Inspector
J. Russell, Acting Senior Resident Inspector
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Approved: H. J. Wong, Chief, Reactor Projects Branch E — 1/12/96 Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection of operational safety verification, maintenance observations, surveillance observations, onsite engineering, plant support activities, and followup-engineering.

Results (Units 1 and 2):

Operations:

- Although a draindown to midloop was generally well controlled, a violation of Technical Specification 6.8.1 was identified for the failure to terminate the draindown utilizing the specified valve in the governing procedure (Section 2.1).

- Communication within the control room during startup was good and the approach to criticality was well controlled (Section 2.2).

- Operator response in performing a rapid downpower and restoring the intake cooling water system was done in a timely manner to prevent a plant trip (Section 2.3).

- The failure of operators to maintain configuration control over an extraction steam line drip pot drain valve created unexpected problems with maintaining condenser vacuum (Section 2.3).

- Operators did not document abnormal indications on the source range instruments and initiate an action request for evaluation and resolution (Section 2.5).

- As a result of the loss of the 12 kV auxiliary transformer, a plan had been implemented to ensure the operability of safety-related equipment including the diesel generators (DGs). However, control room personnel were not aware of housekeeping work being conducted in the DG 1-1 room which could potentially interfere with components critical to the operation of DG 1-1 (Section 2.6).

- After surveillance testing, operators failed to notice the absence of audible indication of the neutron count rate in the control room for 4 hours while the plant was in Mode 6 until identified by the NRC inspector (Section 4.2).

Maintenance:

- Two examples of a violation of Technical Specification 6.8.1 were identified when technicians failed to select the count rate specified by the applicable procedure when verifying the audio count rate function and also failed to restore the audio count rate channel following an operational test of the source range instruments. This resulted in a loss of the audible source range indication in the control room and containment for approximately 4 hours (Sections 4.1 and 4.2).

- There was no formal mechanism for the review of scaffolding to ensure that scaffolds constructed during the outage did not affect safety-related equipment as the plant changed modes (Section 3.1).

- Good attention to detail and questioning attitude was noted as a result of a maintenance technician identifying differences in a relay during installation (Section 5.1).

Engineering:

- A conservative approach and thorough corrective actions were taken in response to concerns identified with inverter relays, inoperable safety injection (SI) system, and SI Pump 2-2 degradation (Section 5.1).

- The inspector identified nonconservative assumptions in the licensee's evaluation of the acceptability of Unit 1 startup and operation using standby startup power from the 230 KV offsite source. The licensee was untimely in fully supporting the operability determination of the 230 kV system (Section 5.4).

Plant Support:

- Fire protection personnel and supervision were not cognizant of the requirements of a procedure used to control fire barriers (Section 6.1).
- A violation was identified for the failure of housekeeping personnel to follow the procedure, when a fire door was blocked from fully closing (Section 6.1).
- The licensee effectively implemented the on-site emergency plan during the annual emergency preparedness exercise (Section 6.2).

Summary of Inspection Findings:

- A violation (275/9516-01) was identified (Section 2.1).
- Two examples of a violation (275/9516-02) were identified (Section 4.1).
- Violation 50-275/9516-03 was identified (Section 6.1).
- Inspector Followup Item 50-275/9515-02 was closed (Section 7.1).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - List of Acronyms

DETAILS

1 PLANT STATUS (71707)

1.1 Unit 1

Unit 1 was in Mode 6 at the beginning of the inspection period. The plant entered Mode 1 and commenced power ascension on November 24, 1995, using standby startup power for the nonsafety-related 12 kilovolt loads normally supplied by the unit auxiliary transformer. After reaching 50 percent power on November 28, 1995, operators manually tripped the reactor following the trip of the operating main feedwater pump (MFP). Operators entered Mode 1 and recommenced the power ascension on November 30, 1995. After reaching 87 percent power on December 3, 1995, the licensee elected to lower power to 52 percent in order to take MFP 1-2 out of service to address control oil problems. After the repair of a leaking hydraulic oil fitting, operators recommenced the power ascension and reached 100 percent power on December 7, 1995. On December 9, 1995, operators lowered power to 50 percent in response to the recurrence of control oil problems on MFP 1-2.

1.2 Unit 2

Unit 2 operated at 100 percent power until November 25, 1995, when operators initiated a rapid load reduction to 30 percent power in response to the trip of Main Circulating Water Pump (MCP) 2-1. Unit 2 was returned to 100 percent power on November 26, 1995, following restoration of MCP 2-1 and remained there the rest of the inspection period.

2 OPERATIONAL SAFETY VERIFICATION (71707)

The inspectors performed this inspection to ensure that the licensee operated the facility safely and in conformance with license and regulatory requirements. The methods used to perform this inspection included direct observation of activities and equipment, observation of control room operations, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and Technical Specifications (TS) limiting conditions for operation, verification of corrective actions, and review of facility records.

2.1 Unit 1 Drain Down

On November 9, 1995, the inspector observed operators perform portions of Operating Procedure OP A-2:III, Revision 13, "Reactor Vessel - Draining to Half Loop/Half Loop Operations With Fuel In Vessel." The operators were draining down the reactor coolant system in preparation for removal of steam generator nozzle dams. The inspector observed the pre-evolution tailboard conducted by the Unit 1 shift foreman (SFM) and the draindown to 108 feet 1 inch, the level that was to be maintained for nozzle dam removal. In accordance with Procedure OP A-2:III, the drain path was via the RHR to

letdown flow control Valve HCV-133 to the letdown heat exchanger. The excess letdown was then diverted through the volume control tank level control Valve LCV-112A to the liquid holdup tanks..

Although the inspector observed that the draindown was generally well controlled by the operators, several exceptions were noted. First, the pre-evolution tailboard did not emphasize the specific prerequisites, precautions, or limitations called out in the procedure. In addition, neither the SFM nor the control operator (CO) discussed the methodology for controlling the draindown. The inspector noted that Procedure OP A-2:III called for initiating draindown by increasing letdown flow to the volume control tank via Valve HCV-133. Prior to the evolution, the inspector observed that Valve HCV-133 was fully open. When asked how letdown flow would be increased, the CO explained that letdown pressure control Valve PCV-135 would be used. The CO stated that Valve PCV-135 provides for more precise control of letdown flow and was the valve used to throttle flow in a different operating procedure, Operating Procedure OP B-1A:I, Revision 8, "CVCS - Charging, Letdown and Seal Injection - Place In Service."

The inspector noted that Procedure OP A-2:III, the applicable procedure, directed the operators to terminate draindown by closing Valve HCV-133 when level reached 109 feet. However, when vessel level reached 109 feet, the inspector observed the CO close Valve PCV-135. When the inspector questioned this action, the SFM explained that since the CO was utilizing Valve PCV-135 to throttle RHR to letdown flow, it was expected that Valve PCV-135 would be used by the CO to terminate the draindown. The inspector did not observe any discussions between the senior CO, designated to read the procedure, SFM or CO regarding the use of Valve PCV-135 versus Valve HCV-133. The inspector also noted that the senior CO was not reading each step to the CO to gain feedback for common understanding. Based upon the concerns raised by the inspector, the licensee made on-the-spot-changes to Procedure OP A-2:III to allow the use of Valve PCV-135 to throttle letdown flow. The licensee also issued a nonconformance report.

The inspector reviewed Procedure OP B-1A:I and the system description for the chemical and volume control system, which was referenced in Procedure OP B-1A:I. The inspector noted that Procedure OP B-1A:I was inconsistent with the reference in that the system description specifically stated that flow from RHR to the letdown heat exchanger was throttled using Valve HCV-133.

The inspector concluded that both supervisory oversight and the tailboard appeared to lack detail and formality. The inspector noted that the various references and procedures involving the use of Valve HCV-133 were inconsistent with each other. The inspector concluded that the operators, in failing to close Valve HCV-133 when vessel level reached 109 feet, violated the requirements of Procedure OP A-2:III. This failure is considered a violation for the failure to follow procedures (Violation 275/9516-01).

2.2 Unit 1 Startup

On November 24, 1995, the inspector observed the preparations for approach to criticality and startup. The two tailboards, one at the beginning of the shift and one before operators began to move rods, were detailed and informative. Personnel involved in the startup were knowledgeable of the procedures they were performing. Although communications within the control room prior to the actual movement of rods were informal, the communications that occurred during the startup were professional and facilitated a controlled atmosphere. Criticality was approached in a cautious manner.

With one exception, the approach to criticality proceeded without incident. The operability of an intermediate power range indicator came into question at one point when the gauge needle failed to track with the redundant instrument channel. After the gauge was tapped, it operated properly. Operators appropriately contacted an instrument and controls technician. The technician explained that the gauge would operate fine as long as it did not fall to zero and lodge there. The gauge had not been fastened into the panel correctly. The installation screw at the bottom of the gauge was too tight, causing the window glass near the zero position of the gauge to interfere with the free motion of the needle. An action request (AR) was written to reinstall the gauge. Once properly installed, it was expected that the interference would be eliminated. The operators proceeded with startup with an operator stationed at the redundant intermediate power gauge on the back panels to ensure that the gauge tracked correctly. The inspector concluded that good communications were maintained during the approach to criticality and that the actions taken were appropriate.

2.3 Unit 2 Down Power

On November 25, 1995, an AO aligning the intake cooling water (ICW) system, after the saltwater side of ICW heat exchanger 2-1 was cleaned, noticed an inrush of air when the heat exchanger was returned to service and that the pumps started cavitating moments later. Operators initiated a rapid load reduction to approximately 220 MWE in response to the decrease in ICW pressure. MCP 2-1 tripped as a result of a time delay designed to trip the pump five minutes after the loss of ICW pressure. Quick operator action to vent the ICW system suction and to increase suction pressure prevented the loss of MCP 2-2. Operators stabilized the plant at 30 percent power and returned MCP 2-1 to service.

The licensee was unable to determine how the air entered the closed system. To prevent recurrence, operations plans to change the procedure to require that the system be vented prior to placing the heat exchanger in service.

Following the load reduction, operators had problems maintaining condenser vacuum. Both high steam jet air ejector off gas flow and high back pressure were experienced. After commencing troubleshooting, operators determined that the cause was condenser air inleakage via an open drain valve on an extraction steam line drip pot.

The level control for the drip pot was under a clearance to be repaired. In preparation for the work, a normally capped, closed drain line had been opened and lined up to allow drainage of the drip pot through its associated drain valve. This change was recorded in the turbine building auxiliary operator (AO) logs. However, the importance of the drain valve in maintaining condenser vacuum at low power levels was apparently not recognized at the time. At higher power levels, the higher pressure of the extraction steam line to the drip pot prevented air inleakage, but at low power the extraction steam lines are at less than atmospheric pressure, providing an open path for air inleakage.

The inspector discussed configuration control of equipment and management's expectations with the Operations Director. The Director explained that the position should have been documented in one of three places: in a clearance, on the white board in the control room, or in operator logs. The director further explained that the SS reviewed the AO logs once a shift and that due to a previous configuration control problem, it was management's expectation that changes in configuration that could affect operations be recorded on the white board in the control room.

The Operations Director later informed the inspector that corrective actions in response to this event would include adding a status board for the turbine in the AO ready room to record configuration changes. The Director also discussed that the option to track configuration changes (with potential to affect plant operations) on the control room status board might be made mandatory.

Although the configuration changes were in the secondary side of the plant and not safety-significant, the inspector concluded that previous practices for documenting plant configuration changes in the secondary system were not effective in ensuring configuration control in this instance.

2.4 Unit 1 Trip

On November 28, 1995, when at 50 percent power, operators actuated a manual reactor trip of Unit 1 after MFP 1-2 tripped. MFP 1-1 was out-of-service for corrective maintenance. Operators tripped the plant before an automatic trip occurred on low-low steam generator level.

Through troubleshooting, the licensee determined that the Channel A speed probe on MFP 1-2 had failed. The licensee suspected that the insulation on the wire lead had been pinched during installation of the probe during the outage. Channel A failed low, causing the MFP to speed up. The pump tripped when the discharge pressure rose above the high discharge pressure trip setpoint. The control system was designed to automatically switch to the other speed channel upon detecting a complete loss of voltage. However, the switch-over did not occur, because Channel A voltage had degraded but had not gone to zero. The licensee replaced the speed probes on both channels on both MFPs.

The inspector concluded that the corrective actions taken were appropriate.

2.5 Unit 1 Power Ascension

On November 29, 1995, the inspector observed as operators performed a plant startup using Operating Procedure OP L-3, Revision 14, "Secondary Plant Startup." The inspector observed the SFM's tailboard for placing in service one of the unit's MFPs and shifting feedwater flow from auxiliary feedwater to main feedwater.

The inspector noted that the pre-evolution tailboard thoroughly covered the procedure's prerequisites, precautions, and limitations. The SFM had previously designated two COs to monitor the control boards. Upon recognizing that the procedural prerequisites required a minimum of three COs, he reassigned staff as necessary.

During the evolution, the inspector noted that the count rate and start-up rate on source range nuclear Instruments NI-31 and NI-32 spiked while the CO manipulated the RCS makeup mode select switch. Manipulation of the makeup mode select switch selects the mode (e.g. boration, dilution) of makeup to the volume control tank of the CVCS. The inspector observed a high count rate (> 10^4 cps) on Instrument NI-31 on several occasions not associated with the manipulation of the switch. These count rates were high enough to trigger a response from the audio count rate circuit and alert the operators. The inspector noted that both source range high voltage power supplies were deenergized during the evolution and questioned the operators about the erroneous indications. The operators dismissed the indications explaining that they were noise induced; however, they could not identify the source of the noise. The problem was not documented for evaluation and disposition. On November 30, 1995, the inspector discussed these observations with the system engineer. The engineer initiated an AR to investigate the noise problem.

The inspector concluded that the overall coordination and control of the Unit 1 power ascension was good. However, the failure of the operators to document the abnormal indications on the source range nuclear instruments was considered to be a poor practice and inconsistent with management expectations on the identification, reporting and resolution of safety-related equipment performance issues.

2.6 Diesel Generator (DG) Risk

Due to the loss of the Unit 1 Auxiliary Transformer 1-1, a safety plan was developed to ensure the availability of key safety systems, including the DGs. On November 21, 1995, as discussed in Section 6.1, the inspector observed housekeeping personnel buffing the floors in the DG 1-1 room and found that they had not contacted the control room before starting work. The inspector was concerned that housekeeping involving the operation of a buffing machine was allowed to occur in the DG rooms, because of the potential to accidentally interfere with components critical to the operation of the DG (e.g. bumping into small instrument lines or bumping into circuit breaker switches). After the inspector discussed the potential risks associated with maintenance activities in the DG rooms, even those activities which did not directly

involve the DG, the operations department determined that the control room should be contacted prior to performing maintenance in areas key to safety while Transformer 1-1 was not available. The inspector concluded that this action was appropriate.

3 MAINTENANCE OBSERVATIONS (62703)

During the inspection period, the inspector observed and reviewed selected documentation associated with the maintenance and problem investigation activities listed below to verify compliance with regulatory requirements, compliance with administrative and maintenance procedures, required quality assurance department involvement, proper use of safety tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. Specifically, the inspector reviewed the work documentation or witnessed portions of the following maintenance activities:

Unit 1

- DG 1-1, 1-2, and 1-3 Fan Air Flow Test
- Component Cooling Water (CCW) Heat Exchanger 1-2 Cleaning
- Performance Test of Centrifugal Charging Pump 1-2

The inspectors concluded that the maintenance activities, which they reviewed, were performed as required.

3.1 Review of Scaffolds

During plant tours, the inspector noted two instances involving scaffolding in which the scaffold request for removal or approval had not been followed. On November 21, 1995, while touring the Unit 1 auxiliary building, the inspector noted a scaffold built under residual heat removal (RHR) Valve 1-HCV-638. The RHR window had already closed. The inspector brought the scaffold to the attention of the SS. The SS had the scaffold reviewed to determine what affect it had on the system, then had it removed. The licensee determined that the scaffold would not have affected the operability of the RHR system.

On November 22, 1995, the inspector noted a scaffold constructed under feed water isolation Valve FW-1-532. The plant was in Mode 3. According to the scaffold request, the scaffold should have received the approval of the SS in order to be allowed to remain during Modes 1, 2, or 3 because of its close proximity to the main steam isolation valve panels. The inspector noted that the SS's approval had not been documented. The inspector discussed the concern with a regulatory compliance engineer. The engineer verified that approval had not been obtained and that the permit should have been signed by the SS. The SS reviewed the scaffold and determined that the scaffold was constructed safely and that it would not have endangered equipment around it.

The outage/maintenance support processes director initiated ARs A0386928 and A0387502 to document the scaffold deficiencies. To ensure that the remaining

scaffolds in the plant did not affect operability, the scaffold department reviewed all outstanding Outage 1R7 scaffold requests on November 22, 1995. No similar notes or restrictions were found. In addition, the licensee completed a field walkdown of all standing scaffolds on November 28, 1995 and found no concerns.

It was noted that the licensee had reviewed scaffolds prior to entering Mode 4 to ensure their qualification for plant operation, but this review was not documented, and the review did not identify the scaffolds in question. To prevent recurrence, the outage/maintenance support processes director determined that a better more formal method to review scaffolds prior to mode transitions or plant heatup should be developed and that the review should be documented prior to restart.

The inspector concluded that the examples identified were not safety significant, but revealed a weakness in the current program to control scaffolds.

4 SURVEILLANCE OBSERVATIONS (61726)

Selected surveillance tests required to be performed by the TS were reviewed on a sampling basis to verity that: (1) the surveillance tests were correctly included on the facility schedule; (2) a technically adequate procedure existed for performance of the surveillance tests; (3) the surveillance tests had been performed at a frequency specified in the TS; and (4) test results satisfied acceptance criteria or were properly dispositioned.

Specifically, portions of the following surveillances were observed by the inspector during this inspection period:

Unit 1

- Integrated Test of Engineered Safeguards and DGs (Procedure STP M-15, Revision 25)
- Nuclear Power Range Channel Analog Channel Operational Test (Procedure STP I-2B, Revision 24A)
- Reload Cycle Initial Criticality (Procedure STP R-30, Revision 8)
- Analog Channel Operational Test Nuclear Source Range (Procedure STP I-4A, Revision 19)
- Digital Rod Position Indicator Functional Test (Procedure STP R-1C, Revision 4)

Unit 2

- Solid State Protection System Train A Actuation Logic Test in Modes 1, 2, 3, or 4 (Procedure STP I-38-A.1, Revision 2)

4.1 Source Range Operational Test

On November 6, 1995, the inspector observed portions of Surveillance Test Procedure STP I-4A, Revision 19, "Analog Channel Operational Test Nuclear Source Range," on Channel NI 31 for Unit 1. The procedure was performed to verify the proper operation of the functions, alarms, and voltage setpoints of the source range instruments. During the operational check of the audio count rate the inspector noted that the procedure required the operators to adjust the count rate on Channel NI 31 to approximately two decades above the actual reading using the operational selector switch. The inspector observed the operators select the "60 cps" fixed input on the Operational Selector Switch. The actual source range counts during this surveillance were recorded by the operators as 10 cps. The inspector questioned the operators to determine why a count rate of two decades greater than actual had not been not selected. The operators explained that selection of a lower count rate was sufficient to verify proper response of the audio count rate circuit and use of a higher count rate ($\approx 10^3$ cps) would cause the audible indication to become a constant tone due to the high frequency of input pulses. Although the inspector acknowledged that proper audio response could be verified using the "60 cps" selection, the procedure did not provide any guidance on the use of a lower count rate.

The inspector discussed the procedural requirement for adjusting the source range counts to verify proper audio response with the system engineer. Based upon that discussion, the inspector concluded that increasing the source range count rate by some factor less than two decades would still meet the intent of the procedure and that this was a common practice for the technicians who performed Procedure STP I-4A. The inspector noted, however, that no attempt had been made to update the procedure to reflect this practice. Based upon the concerns raised by the inspector, the licensee issued an on-the-spot change to Procedure STP I-4A to require the source range count rate only to be raised sufficiently to verify proper response of the audio count rate circuit.

The inspector concluded that the technicians met the intent of the surveillance and that the practice did not affect safety. However, the technicians failed to follow Procedure STP I-4A or receive prior clarification and authorization for the deviation, which is considered an example of the failure to follow procedures (Violation 275/9516-02).

4.2 Source Range Audio Indication

On November 6, 1995, during a control room walkthrough, the inspector observed that the Unit 1 audio count rate circuit N34 had been secured and that no audible signal was available in the control room or containment. Unit 1 was

in Mode 6 (refueling). When questioned, control room personnel had been unaware that the audio circuitry had been turned off. As a result of the inspector's question, the COs restored the audio count rate indication.

The inspector reviewed the licensee's activities affecting operation of the source range audio count rate indication and found that operational checks had been performed on both source range instruments that morning. The surveillance of the second source range instrument was completed at 10:37 a.m., as noted in the CO's log. The operators restored the audible indication at approximately 2:30 p.m. The inspector noted that Procedure STP I-4A directs the technician to select one of the source range instruments for input to the audio count rate circuit following completion of the operational check of the audible indication. The inspector also identified a weakness in the procedure in that the restoration checklist did not include N34 on the list of instruments requiring restoration verification. Had N34 been included on the list, the lack of an audible signal from N34 would likely have been prevented prior to the inspector's identification of the problem.

As a result of the failure to restore audible indication of neutron count rate, personnel in containment were not aware of core reactivity changes and COs had to rely on the high flux at shutdown alarm to trigger actions for protection of personnel working within containment. The inspector noted that the audible source range indication is required by TS 3.9.2 while the unit is in Mode 6. Although operators did not recognize the loss of indication, TS requirements were met in that no core alterations occurred during the 4 hours the indication was turned off.

The inspector concluded that the technicians performing the operational checks on Instrument NI-32 failed to restore the audio count rate circuit as required by Procedure STP I-4A. As a result, audible indication of source range count rate was lost for 4 hours. This is the second example of a violation for failure to follow procedures during performance of Procedure STP I-4A (Violation 275/9516-02).

5 ONSITE ENGINEERING (37551)

The inspectors reviewed and evaluated engineering performance as discussed below.

5.1 Nonseismically Qualified Relays Installed in Unit 1 Vital Inverters

On October 17, 1995, during preventative maintenance, a maintenance technician discovered that replacement relays to be installed in Class 1E Inverter IY12 were not of the same vendor type as the relays already installed in the inverter. Further investigation by the licensee revealed that the relays installed in Positions RL1 and RL2 in the four Unit 1 vital inverters had not been seismically qualified. The licensee verified that Unit 2 inverters had the correct qualified relays installed. On October 20, 1995, the licensee replaced the relays with seismically qualified relays. On October 24, 1995,

the licensee made a 4-hour report to the NRC, when it was determined that this condition could have caused an approximate 10 second loss of instrument power during a seismic event. The licensee retracted the report after completing seismic testing of the relays. They determined that the relays would have performed their intended safety-related function during a design bases seismic event. The inspector concluded that the licensee's actions in response to the discovery were conservative and appropriate. The identification of the discrepancy by an electrician was noted to be an example of good attention-to-detail and a questioning attitude.

5.2 4-Hour Nonemergency Report on Inoperable Safety Injection (SI) System

On November 22, 1995, the licensee made a 4-hour nonemergency report to document a potential loss of capability to transfer to cold leg recirculation. While reviewing a licensee event report from another Westinghouse plant, licensee engineers reviewed the circumstances and determined that for approximately 11 hours on November 20-21, 1989, SI Pump 2-1 and RHR Pump 2-2, both Logic Train A engineered safety feature components, were inoperable due to planned maintenance. Due to the lineup of these systems, the isolation of these components made transfer to cold leg recirculation from SI Pump 2-2 impossible without operator action outside of Emergency Operating Procedure E-1.3, "Transfer to Cold Leg Recirculation." This procedure separates the RHR trains by closing the RHR cross-tie valves, which would have prevented RHR Pump 2-1 from supplying SI Pump 2-2. To prevent recurrence, the licensee plans to change the procedures to prevent taking an RHR and SI pump out of service at the same time.

The inspector reviewed a sample of ECCS flow paths and found no additional lineups in the sample that would allow the loss of a safety function. The components that could, with a single failure, cause the loss of two trains of a system, were administratively controlled. The inspector concluded that the actions taken were appropriate.

5.3 SI Pump 2-2 Degradation

On November 28, 1995, the licensee performed Surveillance Test Procedure STP P-SIP-22, Revision 7, "Routine Surveillance Test of Safety Injection Pump 2-2." SI Pump 2-2 performance was being closely monitored by the licensee due to the identification that Loctite, a product which inhibits nut loosening, had not been applied to the pump's impeller locknuts. Previous surveillance tests performed on SI Pump 2-2 have shown a gradual degradation in the pump's performance since its installation in March 1995. The pump replacement and its subsequent performance degradation were discussed in NRC Inspection Report 50-275/95-14.

As a result of the recent surveillance test, the licensee determined that the pump's performance degraded further and that it reached the licensee's administrative criteria for increased frequency of testing. Consequently, the licensee planned to test SI Pump 2-2 on a 42 day frequency versus the normal frequency of 92 days. The next surveillance was scheduled for January 9,

1996. The licensee was evaluating the need to repair or replace the pump prior to the Unit 2 refueling outage scheduled for Spring 1996.

5.4 230 KV Offsite Power Source

Inspection Report 50-275/95-15 and 50-323/95-15 noted that the licensee planned to use the 230 kV source of offsite power for operation of Unit 1 nonsafety-related 12 kV equipment. Due to lack of supporting documentation, the inspector was unable to determine that the system would continue to remain operable, due to potential low voltage, when peak winter loads were present. Since the inspector had previously reviewed historical load data and determined that area fall and early winter loads were at least 15 percent below assumed worst case loads, the inspector did not have an immediate concern. Peak winter loads will historically occur in January and February. The inspector notified the licensee that he was unable to conclude that their operability evaluation for the 230 kV source of offsite power was acceptable for peak winter loading conditions due to lack of supporting data and calculations. The licensee agreed to provide the supporting data.

The licensee provided a number of documents which indicated that the 230 kV system could be used to provide power to Unit 1 nonsafety-related loads normally supplied by Unit Auxiliary Transformer 1-1, and still remain operable under a specific set of limitations. The main licensee evaluation was contained in a document titled, "Technical Basis Supporting Operation of Unit 1 12 kV Buses D and E from 230 kV Startup Power," Revision 1, dated November 18, 1995.

The inspector reviewed the licensee's documents and determined that five basic conditions were generally required for 230 kV system operability:

- Blocking one-half of the nonsafety-related loads in Unit 2 from automatically transferring to the 230 kV source upon loss of Unit 2 unit auxiliary power;
- At least one of the four units at Morro Bay in operation to support the 230 kV system;
- Site transformer tap changes;
- Peak area loads below design projections; and
- All 230 kV lines in service.

The licensee's analysis was based on computer modeling of the 230 kV and 500 kV systems which are the two sources of offsite power for Diablo Canyon. The licensee used Monte Carlo techniques to demonstrate a 99.5 percent probability with 95 percent confidence that the 230 kV system would provide the required power during unit trips and analyzed accidents.

Based on a review of the licensee's analysis, the inspector had the following comments and concerns. The licensee's operability studies for the 230 kV offsite supply were totally dependent upon the accuracy of the licensee's models for the 230 kV system and the 500 kV system, which supplies most of the 230 kV system power. The licensee assigned only a one percent random error to the modeling of the two systems, based solely on engineering judgement of transmission planning personnel.

On October 21, 1995, the inspector had recognized that the licensee might decide to use the 230 kV system to operate Unit 1 loads. At this time the inspector notified the licensee that he was not familiar with their transmission modeling and requested validation data which compared the results of actual events with what the models would predict. Despite licensee assurances that the models had been checked against actual events many times, as of November 24, 1995, the licensee had provided the inspector only one dynamic comparison of an event on the 500 kV system and one static comparison of an event on the 230 kV system. Although the 500 kV dynamic comparison indicated that the model matched the actual event, there was not correlation within one percent. On November 24, 1995, the inspector informed the licensee that he did not consider that the licensee had provided sufficient data to allow the NRC to understand that their model was one percent accurate. The licensee subsequently provided the inspector two additional comparisons between actual transmission events and computer models for the events. The licensee noted that the comparisons were, "generally good." The inspector determined that these comparisons indicated that the model generally matched the actual event, but were insufficient to validate the one percent accuracy assigned by the licensee.

In addition, the inspector noted that all the modeling studies were done using nonconservative voltamperes reactive (VAR) inputs from the two Diablo Canyon units into the 500 kV system. Basically, the licensee modeled normal Diablo Canyon VAR input, in lieu of worst case or even conservative VAR inputs. The inspector initially questioned the acceptability of modeling nominal VAR flow in October. The inspector noted that normally, the two Diablo main generators were used to help keep the 500 kV system voltage down by importing VARs. Under this condition, if a Diablo unit tripped, the 500 kV system voltage would rise and cause a resultant rise in the 230 kV system voltage, supporting 230 kV system operability. A unit trip during a time of lower VAR inputs would cause a smaller rise in the 500 kV and 230 kV system voltages. The licensee agreed that they sometimes operated the Diablo units with lower VAR inputs, but provided the inspector an evaluation that stated that the method of operation of the Diablo units had little effect upon the 230 kV system. The inspector disagreed with this evaluation, in that the modeling done to support it was not directly comparable to the modeling used in the licensee's evaluation of 230 kV operability. The inspector concluded that the modeling inputs were nonconservative.

The inspector noted that there was less than one percent margin in many of the licensee's studies supporting operability of the 230 kV system. Based on the above two paragraphs, the inspector was unable to conclude that the licensee's

studies were acceptable to demonstrate that the 230 kV system would be operable with a 99.5/95 percent confidence under all the conditions assumed by the licensee. The inspector considered that the 230 kV system could become inoperable at voltage values higher than values determined by the licensee's modeling studies.

However, the inspector concluded that, due mainly to lower than assumed local area loading to date, the 230 kV system voltage had remained sufficiently high to assure operability. The inspector will continue to monitor the acceptability of the 230 kV system to support Diablo Canyon, pending restoration of additional generation at Morro Bay, which will improve system voltage. This has previously been identified as an Inspector Followup Item (IFI 50-275/9515-03).

The inspector also reviewed samples of licensee documents providing operating instructions and evaluations of plant events with 230 kV system power being utilized. The inspector concluded that the licensee was well prepared to operate Unit 1 using 230 kV system startup power and had properly considered accident response which might be affected by the change in power sources.

Based on a review of the licensee's evaluation of the 230 kV system since September 1995, the inspector considered that the licensee had not done a timely or effective job of demonstrating offsite power operability for both Diablo Canyon units.

6 PLANT SUPPORT ACTIVITIES (71750)

The inspectors evaluated plant support activities based on observation of work activities, review of records, and facility tours. The inspectors noted the following during these evaluations.

6.1 DG Fire Door

While touring the Unit 1 DG rooms on November 21, 1995, the inspector noted that Door 107, the fire door between DG 1-1 and 1-2 rooms, was blocked open with a floor buffer cord. The door would not completely close or latch. According to Administrative Procedure OM8.ID2, Revision 2, "Fire System Impairment," conditions that could represent an impairment of a fire system were required to be reported to the fire protection specialist and to the SFM. After questioning of the housekeeping personnel involved with the buffing activity, the SFM, the fire protection supervisor, and the fire protection specialist, the inspector determined that neither the fire protection specialist nor the SFM had been notified of the impairment. This was significant, because absent notification, operations was unaware of the impairment, and its restoration was not controlled, because it had not been entered in the licensee's Equipment Control guideline and an AR had not been written as required in the procedure. Following the procedures would have provided an adequate means of tracking the status of the impaired fire door.

During questioning of the fire protection supervisor and the fire protection specialist, the inspector identified an additional concern in that the fire protection supervisor and the fire protection specialist were unaware of the requirement to contact the SFM and the fire protection specialist.

The inspector concluded that the failure to contact the SFM and the fire protection specialist was a failure to follow Procedure OM8.ID2. In this case there was little safety significance in blocking the fire door open, because personnel were present to close the door in the event of a fire. However, due to the loss of Auxiliary Transformer 1-1, additional measures were to have been taken to assure the availability of safety systems, including the DGs. In addition, the inspector determined that the procedure to notify personnel was not fully understood by the safety and fire protection supervisor and the fire protection specialist. Furthermore, the concern identified by the inspector was not formally documented by the licensee in an AR until after the inspector questioned the incident several times. This was identified as a failure to follow procedures (Violation 275/9516-03).

6.2 Licensee Annual Emergency Preparedness Drill

On November 29, 1995, the inspector observed portions of the licensee's annual emergency preparedness exercise. The annual exercise of the licensee's emergency plan was required by Appendix E to 10 CFR Part 50. The inspector observed radiological emergency response operations in the control room simulator at the beginning of the drill and in the technical support center (TSC) during the latter portions of the drill. Observations focused on offsite notifications, emergency response facility activation, emergency classification and protective action recommendations.

The inspector noted that emergency classification and notifications were well executed by the operating crew in the control room simulator. The SS quickly recognized that the loss of both trains of RHR would require an Alert declaration if not restored within 15 minutes. After 15 minutes had elapsed without RHR restoration, the event was appropriately classified and notifications were initiated in a timely manner.

Within 1 hour following the Alert declaration, the TSC was manned and activated in accordance with the licensee's procedures. Communications between the TSC, control room simulator, and operational support center were good. Direction and control of response actions was also generally good. However, on several occasions the site emergency coordinator's (SEC's) advisors provided direction to the operating crew and operational support center without apprising the SEC of the actions beforehand. Although the inspector observed that the advisors were extremely knowledgeable, the failure to obtain the SEC's concurrence on response actions usurped the SEC's authority and could have led to conflicting directives, when there were competing interests from other parts of the emergency response organization.

The assistant SEC and the operations advisor both provided the SEC with timely event classification recommendations at the Site Area Emergency and General

Emergency levels. The protective action recommendations issued by the SEC were consistent with licensee procedures. The radiological advisor kept the SEC informed of potential high radiological exposure evolutions where personnel could have the potential to exceed the limits of 10 CFR Part 20. The radiological advisor also made appropriate recommendations to the SEC regarding the issuance of potassium iodide to emergency response personnel.

The inspector concluded that the licensee effectively implemented the onsite radiological emergency response plan during the annual emergency preparedness exercise.

7 FOLLOWUP-ENGINEERING (92903)

7.1 (Closed) Inspector Followup Item 275/9515-02: CCW Heat Exchanger Fouling Factor

This item involved the licensee's discovery that the fouling factor for the RHR heat exchangers and containment fan cooler units was significantly less than that assumed in the plant design. Consequently, the amount of heat transferred to the CCW system during design basis accidents was greater, causing the CCW temperature to exceed design limits in worst case scenarios. The inspector's followup action was to review the licensee's final analysis and compensatory measures.

The inspector reviewed Operability Evaluation 95-11, Revision 0, "Operability of Cooling Water System with Analyzed CCW Water Temperatures Higher than Current Design Basis," which applied to both units. The inspector interviewed operators and system engineers, reviewed applicable plant and emergency operating procedures, and walked down the CCW heat exchangers.

The licensee conservatively assumed that the reduced fouling factor also applied to the containment fan cooling units. Using WCAP 14282 methodology (a Westinghouse computer simulation of the containment response during accident conditions), the licensee determined that with no compensatory measures, CCW could exceed design limits. This could potentially result in degradation of equipment cooled by the CCW during post accident conditions. As a result, the licensee planned to revise procedures to ensure the capability of returning either the second auxiliary saltwater pump or CCW heat exchanger to service or opening the auxiliary saltwater system unit cross-tie within 20 minutes of accident initiation. The licensee also instituted controls to monitor refueling water storage tank temperature to ensure that it did not exceed 75°F, with the analyzed limit being 80°F. The licensee planned on keeping these measures in place until March 1996, at which time the licensee anticipated that analysis could demonstrate operability of CCW cooled components without any compensatory measures.

Based on the review mentioned above, the inspector concluded that the analysis and compensatory measures currently in place were adequate. The inspector noted that the licensee was restricting maintenance on CCW heat exchangers

until procedures could be updated to allow for recovery of the heat exchanger within 20 minutes, if a loss of coolant accident should occur. The inspector considered that once the licensee determined the CCW temperature could potentially exceed design conditions under certain load scenarios, the subsequent evaluation and interim corrective actions appeared to provide reasonable assurance that maximum CCW temperature would not exceed design limits. This item will be closed. Further review will be completed and documented during the review of Licensee Event Report 95-013.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

G. M. Rueger, Senior Vice President and General Manager, Nuclear Power Generation Business Unit
W. H. Fujimoto, Vice President and Plant Manager, Diablo Canyon Operations
L. F. Womack, Vice President, Nuclear Technical Services
M. J. Angus, Manager, Regulatory and Design Services
*D. R. Adams, Engineer, Nuclear Safety Engineering
C. R. Beck, Foreman, Technical Maintenance
*J. R. Becker, Director, Operations
S. Bednarz, Engineer, System Engineering
D. H. Behnke, Senior Engineer, Regulatory Services
F. Bosseloo, Assistant to Vice President, Nuclear Power Generation Business Unit
*S. S. Bowen, Supervisor, Instrumentation & Control, Electrical Engineering
*D. K. Cosgrove, Supervisor, Safety and Fire Protection
W. G. Crockett, Manager, Engineering Services
*R. N. Curb, Manager, Outage Services
T. F. Fetterman, Director, Electrical and Instrumentation and Control Systems Engineering
T. L. Grebel, Director, Regulatory Support
D. L. Gouveia, Engineer, Nuclear Quality Services
C. R. Groff, Director, Secondary Systems Engineering
C. D. Harbor, Engineer, Regulatory Support
*J. R. Hinds, Director, Quality Control
R. J. LaVelle, Foreman, Mechanical Maintenance
R. J. Magruder, Shift Supervisor, Operations
*D. B. Miklush, Manager, Operations Services
J. E. Molden, Manager, Maintenance Services
*P. S. Natividad, Engineer, Regulatory Services
M. D. Nowlen, Senior Engineer, Technical Maintenance
P. T. Nugent, Senior Engineer, Regulatory Support
*D. H. Oatley, Director, Mechanical Maintenance
R. P. Powers, Manager, Quality Services
*B. H. Patton, Senior Engineer, Support Engineering
*H. J. Phillips, Director, Technical Maintenance
R. G. Todaro, Director, Security
*D. A. Taggert, Director Nuclear Safety Engineering
*D. A. Vosburg, Director, NSSS Engineering
R. A. Waltos, Director, Balance of Plant Engineering
*J. C. Young, Director, Quality Assurance

1.2 NRC Personnel

*J. L. Dixon-Herrity, Senior Resident Inspector, Acting
*S. A. Boynton, Resident Inspector

*Denotes those attending the exit meeting on December 12, 1995.

2 EXIT MEETING

An exit meeting was conducted on December 12, 1995. 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

AO	auxiliary operator
AR	action request
CCW	component cooling water
CO	control operator
CVCS	chemical and volume control system
DCM	design control memorandum
DG	diesel generator
ICW	intake cooling water
MCP	main circulating pump
MFP	main feedwater pump
NI	nuclear instrument
RHR	residual heat removal
SEC	site emergency coordinator
SFM	shift foreman
SI	safety injection
SS	shift supervisor
STP	surveillance test procedure
TS	Technical Specification
TSC	technical support center

E-Mail report to D. Nelson (DJN)
E-Mail report to NRR Event Tracking System (IPAS)

bcc to DMB (IE01)

bcc distrib. by RIV:

L. J. Callan
DRS-PSB
Branch Chief (DRP/E, WCFO)
RIV File
M. Hammond (PAO, WCFO)
Resident Inspector
MIS System
Senior Project Inspector (DRP/E, WCFO)
Branch Chief (DRP/TSS)
Leah Tremper (OC/LFDCB, MS: TWFN 9E10)

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*previously concurred

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