UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

July 28, 2003

Gregory M. Rueger, Senior Vice
  President, Generation and Chief Nuclear Officer
Pacific Gas and Electric Company
Diablo Canyon Power Plant
P.O. Box 3
Avila Beach, California 93424

SUBJECT: DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000275/2003006 AND 05000323/2003006

Dear Mr. Rueger:

On June 28, 2003, the U.S. Nuclear Regulatory Commission completed an inspection at your Diablo Canyon Power Plant, Units 1 and 2, facility. The enclosed integrated report documents the inspection findings that were discussed on July 3, 2003, with Mr. James R. Becker and members of your staff.

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

There were five findings of very low safety significance (Green) identified in this report. Two of the findings were NRC-identified and three were self-revealing. However, because of their very low risk significance and because they are entered into your corrective action program, the NRC is treating these five findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Diablo Canyon Power Plant.

Pacific Gas and Electric Company operated under voluntary bankruptcy proceedings during this inspection period. The NRC has monitored plant operations, maintenance, and planning to better understand the impact of the financial situation and how it relates to your responsibility to safely operate the Diablo Canyon reactors. NRC inspections, to date, have confirmed that you are operating these reactors safely and that public health and safety is assured.

Since the terrorist attacks on September 11, 2001, NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of Temporary Instruction 2515/148 was completed at all commercial power nuclear power plants during Calender Year 2002 and the remaining inspection activities for Diablo Canyon Power Plant were completed in January 2003. The NRC will continue to monitor overall safeguards and security controls at Diablo Canyon Power Plant.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

William B. Jones, Chief
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Division of Reactor Projects

Dockets: 50-275
50-323
Licenses: DPR-80
DPR-82

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Inspection Report 05000275/2003006
and 05000323/2003006
w/attachment: Supplemental Information

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-275, 50-323
Licenses:	DPR-80, DPR-82
Report:	05000275/2003006 05000323/2003006
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	March 30 through June 28, 2003
Inspectors:	D. L. Proulx, Senior Resident Inspector T. W. Jackson, Resident Inspector Ryan E. Lantz, Senior Emergency Preparedness Inspector Lawrence E. Ellershaw, Senior Reactor Inspector Engineering and Maintenance Branch James P. Adams, Reactor Inspector, Engineering and Maintenance Branch Grant F. Larkin, Resident Inspector, Waterford Steam Electric Station, Unit 3 T. O. McKernon, Senior Operations Engineer G. W. Johnston, Senior Operations Engineer
Approved By:	W. B. Jones, Chief, Projects Branch E Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000275/2003-006, 05000323/2003-006; 03/30/03 - 06/28/03; Diablo Canyon Power Plant Units 1 and 2; Equipment Alignment, Personnel Performance Related to Nonroutine Plant Evolutions and Events, Problem Identification and Resolution, and Event Followup.

This report covered a 13-week period of inspection by resident inspectors and announced inspections by a senior emergency preparedness inspector, senior operations inspectors, a senior reactor inspector, a resident inspector, and a reactor inspector. Five Green noncited violations were identified. Two of the findings were NRC-identified and three were self-revealing. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609 "Significance Determination Process." Findings for which the does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing, noncited violation of 10 CFR Part 50, Appendix B, Criterion V occurred because of a failure to accurately reflect wiring changes in drawings following a design modification. Subsequently, deficient drawings were used by maintenance personnel in another design modification and contributed to inadvertent, inward control rod motion that reduced reactor power by approximately 2 percent.

  Using Example 4.b of Inspection Manual Chapter 0612, Appendix E, the finding is greater than minor since maintenance personnel performed activities with the deficient drawings and without verifying the function of the leads, caused a small plant transient. The finding, which is under the initiating events cornerstone, was of very low safety significance since operators performed in a timely, appropriate manner. Also, the transient was not severe enough to challenge the capability of the plant's mitigating equipment. The finding was reviewed against the initiating event screening criteria documented in Inspection Manual Chapter 0609, Appendix A, Attachment 1, Significance Determination Process Phase 1 Screening Worksheet for Initiating Event, Mitigating Systems and Barrier Cornerstones. The finding is of very low safety significance because the condition did not contribute to a loss of coolant initiator, would not contribute to the likelihood a mitigating system would not be available and did not involve an external event initiator. In addition, the operators responded in a timely and appropriate manner. Plant mitigating equipment was not challenged by the transient (Section 1R14.1).

- Green. A self-revealing, NCV of Technical Specification 5.4.1.a was identified for the failure to use the latest revision of a surveillance procedure. This finding resulted in pressurizer power-operated relief Valve RCS-2-PCV-456, opening during a channel operability test. Maintenance personnel failed to verify the correct procedure revision was being used prior to performing work.

The finding is greater than minor because it had an actual impact of opening the pressurized power-operated relief valve, which is a precursor to a nonsignificant event (i.e., relief valve stuck open). Using Inspection Manual Chapter 0609, "Significance Determination Process," Phase 1 Screening Worksheet, this finding is considered a primary system loss-of-coolant-accident initiator, requiring a Significance Determination Process Phase 2 analysis. Using Significance Determination Process Phase 2 notebook, "Risk-Informed Inspection Notebook For Diablo Canyon Power Plant – Units 1 and 2," Revision 1, the deficiency is assumed to impact the "Stuck-Open Power Operated Relief Valve" accident initiator only. The condition existed for less than 3 days. The inspectors considered that performance of the surveillance test would cause the valve to open and therefore increased the likelihood of the power-operated relief valve sticking open in the Phase 2 analysis. All mitigating equipment, including the power-operated relief valve low pressure interlock and power-operated relief valve block valve, was assumed operable, and operators were able to respond to a potential event. The finding was determined to be of very low safety significance using the Significance Determination Process Phase 2 Analysis and the results were reviewed by an NRC senior reactor analyst (Section 1R14.2).

Cornerstone: Mitigating Systems

- Green. A self-revealing, NCV of 10 CFR Part 50, Appendix B, Criterion XVI was identified for the failure to promptly identify and correct a leak in Check Valve FW-2-370 and the backward installation of Check Valve FW-2-377 disk. This finding resulted in minor backflow of feedwater to Auxiliary Feedwater Pump 2-2.

  Using Inspection Manual Chapter 0612, Appendix E, Example 5.b, the finding is more than minor because Auxiliary Feedwater Pump 2-2 was returned to service, prior to the discovery of the leak and the incorrect check valve reassembly, despite auxiliary feedwater system backflow alarms and industry experience on proper assembly of check valves. The finding did not result in sufficient backflow and temperature increase to prevent the pump from providing adequate auxiliary feedwater flow to the steam generators. Therefore, using the Significance Determination Process Phase 1 Worksheet, as described in Inspection Manual Chapter 0609, Appendix A, the finding was determined to be of very low safety significance. Specifically, the finding did not result in a loss of safety function or screen as potentially risk significant from an external event (Section 1R04.4).

- Green. An NRC-identified NCV of 10 CFR Part 50, Appendix B, Criterion XVI was determined for the failure to identify and correct a faulty automatic voltage regulator card that resulted in Diesel Engine Generator 1-3 failures. Diesel

Engine Generator 1-3 remaining in service for over 6 months with a faulty automatic voltage regulator card. Overall there were three occasions where the diesel engine generator did not achieve its required voltage rise time.

The finding was more than minor when assessed using Inspection Manual Chapter 0612, Appendix E, Example 4.f. Similar to the example, Diesel Engine Generator 1-3 was inoperable from August 31, 2002, to February 23, 2003, which is the time period that the fault in the automatic voltage regulator card was determined to exist. Using the Significance Determination Process Phase 1 Worksheet in Inspection Manual Chapter 0609, the inspectors determined that there was an actual loss of a safety function for greater than the diesel engine generator Technical Specification allowed outage time, which required a Significance Determination Process Phase 2 analysis. The finding was reviewed by senior reactor analysts and an engineer with the Office of Nuclear Reactor Regulation to identify the sequences to be analyzed. Specifically, the sequences involving a loss of offsite power with a large break loss-of-coolant-accident were evaluated since Diesel Engine Generator 1-3 exhibited a slow voltage rise time only. In all other sequences, the emergency alternating current safety function was credited. An additional mitigating factor is the two residual heat removal pumps were located on the other two vital buses. The Significance Determination Process Phase 2 analysis determined that the finding was of very low safety significance (Section 4OA2).

Cornerstone: Barrier Integrity

- Green. An NRC-identified noncited violation of Technical Specification 5.4.1.a was determined for the failure to promptly notifying the shift foreman, as required by procedure, when it was ascertained that containment closure could not be established during reduced inventory operations. Containment closure could not be established because of a stuck fuel transfer cart that prevented the fuel transfer tube isolation valve from being closed. Pacific Gas and Electric Company personnel calculated that during the 2.5-hour period the fuel transfer tube could not be isolated, the reactor coolant system could potentially begin boiling within 22 minutes, if shutdown cooling was lost.

  The finding is more than minor because it affected the barrier cornerstone objective of providing reasonable assurance that the containment would preclude the release of radionuclides from accidents or events. The inspectors evaluated the safety significance of the finding using Inspection Manual Chapter 0609, Appendix G, Shutdown Operations. Section IV to Containment Control Guidelines was considered and a Significance Determination Process Phase 2 and 3 analysis was determined to be appropriate because of the impact on the ability to isolate the fuel transfer canal. The initial conditions considered for the containment integrity significance determination process were: (1) the condition occurred within 8 days of the outage, (2) the reactor vessel level was less than

23 feet from the top of the reactor vessel flange, (3) the reactor coolant system was vented, (4) a robust mitigation capability was in place and the condition existed for less than 8 hours. Utilizing Table 6.4 , Phase 2 Risk Significance - Type B Findings at Shutdown (For POS 1/TW-E and POS 2/TW-E in which the finding occurs during the first 8 days of the outage) the finding was potentially white. Note 2, to Table 6.4, specifies that for Type B findings (does not effect core damage frequency) that exist for less than 8 hours, then the color of the finding is reduced by an order of magnitude. A senior reactor analyst also reviewed the reactor plant initial conditions, fuel transfer canal configuration and mitigating strategies specified in Pacific Gas and Electric Company's outage plan. Based on Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," and an independent Phase 3 review, the NRC staff concluded that the finding was of very low safety significance (Section 4OA3.6).

REPORT DETAILS

Summary of Plant Status

Diablo Canyon Unit 1 began this inspection period at 100 percent power. On June 27, 2003, operators reduced reactor power to approximately 50 percent to support cleaning of the circulating water tunnels. Unit 1 remained at 50 percent power until the end of the inspection period.

Diablo Canyon Unit 2 began this inspection period in Mode 2 (Startup) at 3 percent power. Operators increased reactor power and reached Mode 1 (Power Operations) on March 30, 2003. Power was increased to approximately 64 percent power on April 2. Operators then reduced power to 50 percent power, on that same day, to facilitate maintenance on main feedwater Pump 2-2. On April 4, operators commenced a shutdown of Unit 2 reactor due to evidence of backleakage from an auxiliary feedwater (AFW) check valve that had been installed incorrectly during Refueling Outage 2R11. The unit reached Mode 3 (Hot Standby) on April 4 and Modes 4 (Hot Shutdown) and 5 (Cold Shutdown) on April 5. Following repairs to the AFW check valve and a main generator radial seal, operators commenced a reactor coolant system heat-up. Unit 2 reached Mode 4 on April 10 and Mode 3 on April 11. On April 15, operators commenced a reactor startup, entering Mode 2. Mode 1 was achieved on April 15 as operators continued to increase reactor power. On April 20, operators achieved 100 percent power, but reduced power to 96 percent shortly thereafter to maintain adequate margin between actual reactor coolant system flow and the flow required by the Technical Specifications. The reduced margin for reactor coolant system flow was a result of steam generator tube plugging during Refueling Outage 2R11. Upon resolution of the reactor coolant system flow margin concerns, operators returned Unit 2 to 100 percent power on April 23. Unit 2 remained at 100 percent power until the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignments (71111.04)

Partial System Walkdowns

.1 Unit 1 Auxiliary Feedwater (AFW) System

a. Inspection Scope

On April 1, 2003, while AFW Pump 1-1 was in a maintenance outage window, the inspectors performed a partial system walkdown of Unit 1 AFW Pumps 1-2 and 1-3. The inspectors observed valve alignment, the availability of electrical power and cooling water, labeling, lubrication, ventilation, structural support, and material condition. The inspectors used Drawing 106703, “Feedwater,” Sheet 3, Revision 61, during the inspection.

b. Findings

No findings of significance were identified.

.2 Unit 2 Safety Injection (SI) Pump 2-1

a. Inspection Scope

On May 7, 2003, while AFW Pump 2-3 and SI Pump 2-2 were in a maintenance outage window, the inspectors performed a partial system walkdown of SI Pump 2-1. The inspectors observed valve alignment, the availability of electrical power and cooling water, labeling, lubrication, ventilation, structural support, and material condition. The inspectors used the following documents during the inspection:

- Procedure OP B-3A:I, "Safety Injection System – Make Pump Available," Revision 8B

- Procedure OP B-3A:II, "Safety Injection System Alignment Verification for Plant Startup," Revision 17

- Drawing 107709, "Safety Injection,"

  - Sheet 3, Revision 44
  - Sheet 4, Revision 45

b. Findings

No findings of significance were identified.

.3 Unit 2 Auxiliary Saltwater (ASW) Pump 2-1

a. Inspection Scope

On June 11, 2003, while ASW Pump 2-2 was in a maintenance outage window, the inspectors performed a partial system walkdown of ASW Pump 2-1. The inspectors observed valve alignment, the availability of electrical power, labeling, lubrication, ventilation, structural support, and material condition. The inspectors used the following documents during the inspection:

- Procedure OP E-5:I, "Auxiliary Saltwater System - Make Available," Revision 22

- Drawing 106717, "Saltwater,"

  - Sheet 7A, Revision 127
  - Sheet 9, Revision 125

b. Findings

No findings of significance were identified.

.4 Complete System Walkdown

Unit 2 AFW Pump 2-2

a. Inspection Scope

On March 26, 2003, high temperature alarms for AFW Lead 2-1 to Steam Generator 2-1 activated in the control room. Pacific Gas and Electric Company personnel believed the alarm was coming in because the AFW discharge check valves in that lead were not properly seated. Operators attempted to reseat the discharge check valves by running AFW Pump 2-2 and suddenly shutting off AFW flow to Steam Generator 2-1. After several attempts to clear the alarm failed, maintenance personnel replaced the second-off AFW discharge check valve (FW-2-370) from the main feedwater line. On April 4, 2003, radiography of AFW discharge check valve indicated the valve disk had been installed backwards and could potentially block AFW flow to Steam Generator 2-1. Operators shutdown Unit 2 reactor to Mode 5 to perform repairs on that valve.

The inspectors reviewed: (1) past events and documents regarding AFW discharge check valve performance, (2) the potential for generic check valve issues, (3) Pacific Gas and Electric Company's root cause determination for the discovered conditions, (4) corrective actions Pacific Gas and Electric Company has taken, (5) human error contribution to the discovered conditions, and (6) Pacific Gas and Electric Company's use of industry experience.

b. Findings

Background. On March 26, 2003, operators began to receive high temperature alarms for the AFW Lead 2-1 to Steam Generator 2-1. Using Procedure PK09-16, "Aux FW System Leakage/Temp Hi," Revision 1, operators monitored the AFW discharge line temperature every 4 hours to ensure no detectable temperature rise at the AFW pumps. Using temperatures observed along the AFW discharge line, operators determined that slight backleakage was associated with at least two out of three of the discharge check valves from AFW Pump 2-2 to the main feedwater line to Steam Generator 2-1.

The AFW discharge line ties into the main feedwater lead for Steam Generator 2-1 just before the main feedwater lead enters the containment building. Just upstream of the AFW/main feedwater tie is the first-off discharge check valve, Valve FW-2-377. The discharge of AFW Pumps 2-1 and 2-2 join upstream of the first-off discharge check valve. Upstream from the junction of AFW Pumps 2-1 and 2-2 discharge piping is a second-off discharge check valve for AFW Pump 2-2, Valve FW-2-370. The third discharge check valve associated with AFW Pump 2-2 is Valve FW-2-369, which is located immediately at the discharge of the pump. Engineers suspected Valves FW-2-377, FW-2-370, and FW-2-369 to be allowing backleakage since Valve FW-2-370 was warmer than normal.

Backleakage of AFW discharge check valves had been experienced on both units for several years, as evidenced by the AFW discharge line high temperature alarms. Engineers believed that it was difficult to get a good seal on the discharge check valves since it involves a hard seat (metal-on-metal). High temperature alarms were most common after an outage when operators performed a swap from AFW to main feedwater. The increased steam generator pressure at lower reactor power increased the amount of backleakage as a result of increased differential pressure across the discharge check valves. Engineers recommended that operators start the AFW pumps to open the AFW check valves and then suddenly cut-off AFW flow. The purpose of this maneuver was to seat the discharge check valves, in hopes that a better seal could be achieved. From March 26 to April 2, 2003, operators performed the recommended maneuver twice and also ran AFW Pump 2-2 approximately four times a shift to clear the high temperature alarm.

On April 2, the system engineer noted indication of feedwater backleakage to AFW Pump 2-2. Maintenance personnel initiated work to replace Valve FW-2-370 and inspect Valve FW-2-369. The first-off check valve could not be inspected with the unit on-line, since there was no way to isolate the valve from the main feedwater system. On April 4, maintenance personnel completed work on Valve FW-2-370 and performed radiography to examine the new welds for that valve. Additionally, maintenance personnel had lapped the disk for Valve FW-2-369.

Prior to being replaced, Valve FW-2-370 was a Borg-Warner, 3-inch swing check valve. This type of Borg-Warner check valve has the disk attached to the valve bonnet versus the valve body. Proper assembly of this type of valve requires the vertical and radial alignment of the bonnet be correctly set. Improper assembly has lead to backleakage through these check valves. The newly installed valve was an Anchor-Darling, 3-inch swing check valve. The new valve had the disk attached to the valve body, which eliminated the vertical and radial alignment problems associated with the Borg-Warner valve. When the Borg-Warner valve was removed, maintenance personnel pressure tested the valve and identified a small hole between the valve body and the valve body seat. The leak was 0.75 gpm when tested at atmospheric pressure

Upon completion of radiography on the newly installed Valve FW-2-370, Pacific Gas and Electric Company decided to perform radiography on Valve FW-2-377 to identify potential leakage paths in that valve. The results of the radiography showed that the valve disk had been installed backwards. Valve FW-2-377 was the same type of Borg-Warner check valve as Valve FW-2-370. When this valve was reinstalled during the last refueling outage, the radial alignment of the bonnet was installed180 degrees out (reversed) from its correct alignment. With the check valve disk backwards, the main concern was the potential of the valve to limit AFW flow to Steam Generator 2-1.

Operators declared AFW Pumps 2-1 and 2-2 inoperable since the discharge flows of both pumps go through Valve FW-2-377. In accordance with Technical Specification 3.7.5.C.1, and to support check valve replacement, operators shutdown Unit 2 reactor to Mode 5 on April 4. The Borg-Warner check valve was replaced by an Anchor-Darling 3-inch swing check valve. Maintenance activities associated with Valve FW-2-377 were completed on April 7. Unit 2 reactor returned to Mode 1 following repairs to a main generator seal on April 15.

Introduction. A Green NCV was identified for the failure to identify and correct a condition adverse to quality. Specifically, the failure to adequately incorporate industry experience and the failure to assess the cause of high temperature alarms on an AFW discharge line allowed minor feedwater backflow to an AFW pump.

Description. The inspectors reviewed previous action requests (ARs) that documented high temperature alarms on AFW discharge lines. Additionally, the inspectors reviewed past industry experience associated with Borg-Warner swing check valves as they relate to improper vertical and radial alignment. The inspectors determined that there were several examples were Pacific Gas and Electric Company failed to adequately evaluate information that would have: (1) prevented Valve FW-2-377 from being installed backwards and (2) would have prevented Unit 2 from operating with a leak in Valve FW-2-370.

The inspectors discovered that backleakage in AFW Discharge Lead 2-1 had first been identified on December 11, 1998, and documented in AR A0473010. The backleakage was discovered when maintenance personnel were determining the cause of calibration error between the temperature element for AFW Discharge Lead 2-1 and the temperature elements in the other three AFW discharge leads. AR A0473010 was taken to “history” (no action taken) after the alarm cleared.

On October 28, 1999, the high temperature alarm for AFW Lead 2-1 became active following Refueling Outage 2R9. Operators attempted to clear the alarm by running AFW Pump 2-2 in attempts to get a better seating for the three discharge check valves. The high temperature alarm cleared on November 5, but came in again following a forced shutdown to Mode 3 on November 21. The alarm then cleared on the same day. These events were documented in ARs A0496285 and A0498016. The first AR was taken to history with no action taken and the second AR was closed per the system engineer.

On December 10, 2000, following a forced shutdown, the high temperature alarm for AFW Lead 2-1 became active. Operators cleared the alarm by running AFW Pump 2-2 on December 11. This event was documented in AR A0522157.

On May 30, 2001, following Refueling Outage 2R10, the high temperature alarm for AFW Lead 2-1 became active. The alarm cleared after operators ran AFW Pump 2-2. However, the alarm activated again in February 2002 and November 2002 following reactor shutdowns. Both alarms were cleared by running AFW Pump 2-2. Pacific Gas and Electric Company staff decided to perform corrective maintenance on Valves FW-2-369, FW-2-370, and FW-2-377 during Refueling Outage 2R11. The series of high temperature alarms following Refueling Outage 2R10 were documented in AR A0534762. This AR was closed in February 2003 based on the work performed on the two AFW 2-1 lead check Valves FW-2-370 and 377 and the AFW Pump 2-1 discharge check Valve FW-2-369 during 2R11.

Following Refueling Outage 2R11, the high temperature alarm for AFW Lead 2-1 became active. After several attempts to clear the alarm by running AFW Pump 2-2 failed, and the evidence that there was backflow to AFW Pump 2-2, Pacific Gas and Electric Company decided to replace Valve FW-2-370. The valve that was replaced was pressure tested and found to have a significant leak between the valve seat and body. Pacific Gas and Electric Company could not determine the period of time this leak had existed. The inspectors identified that Pacific Gas and Electric Company's failure to promptly and effectively address the high temperature alarms in AFW Lead 2-1 allowed Unit 1 to operate with substantial backleakage through check Valve FW-2-370. Subsequently, the leak in Valve FW-2-370 contributed to the backflow to AFW Pump 2-2 following Refueling Outage 2R11.

With respect to the reversed installation of internals for Valve FW-2-377, the inspectors reviewed Licensee Event Report 92-005-01 for Palo Verde Nuclear Generating Station, Unit 1. This report identified a similar situation where a Borg-Warner swing check valve had internals installed backwards. As with Valve FW-2-377, the incorrect reassembly of the check valve did not reveal itself in surveillance tests (forward flow test). Palo Verde presented its experience at the 1992 Nuclear Industry Check Valve Group Meeting, which Pacific Gas and Electric Company was in attendance. Pacific Gas and Electric Company staff reviewed the experience and determined that sufficient actions had previously been taken in Field Change Task 1365 to the Borg-Warner Vendor Instruction Manual to prevent the same event from occurring at Diablo Canyon. The inspectors reviewed Vendor Instruction Manual 678620-21, "Borg-Warner Corporation 3-inch Swing Check Valve Parts No. 74330," Revision 9, and observed that there were several steps to ensure the valve was installed in the proper radial alignment. The vendor instruction manual required the disk center-line be scribed on the bonnet with an arrow indicating the direction of flow. Also, the manual required, during reassembly of the valve, that the disk center-line be within 6.5 degrees of rotation with the valve body center-line. However, the inspectors noted that the reassembly instruction did not require confirmation of correct flow direction, using the arrow. Additionally, Procedure MP M-51.14, "Generic Check Valve Inspection," Revision 8, did not require the verifying engineer to ensure proper reassembly of the check valve and in particular the correct flow direction. The inspectors noted that the engineer had incorrectly identified that Valve FW-2-377 was assembled correctly.

<u>Analysis</u>. The failure to promptly identify and correct conditions adverse to quality regarding the AFW system impacted the Mitigating Systems Cornerstone. Using

Inspection Manual Chapter 0612, Appendix E, Example 5.b, the finding is more than minor because AFW Pump 2-2 was returned to service, on several occasions without having implemented adequate corrective actions to identify the leakage past Valve FW-2-370 and subsequently that Valve FW-2-377 was incorrectly reassembled. Several instances were noted where AFW system backflow alarms occurred to identify the leakage past Valve FW-2-370 and specific industry experience existed on the proper assembly of Borg-Warner check valves (FW-2-377). The finding did not result in sufficient backflow and temperature increase to prevent the AFW train from providing adequate AFW flow to the steam generators. Therefore, using the Significance Determination Process Phase 1 Worksheet, as described in Inspection Manual Chapter 0609, Appendix A, the finding was determined to be of very low safety significance. The finding did not result in a loss of safety function or screen as potentially risk significant from an external event.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions,” requires, in part, that measures be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, high temperature alarms for AFW Lead 2-1 became active numerous times from 1998 to 2003 before a leak in Valve FW-2-370 was discovered. Additionally, it was learned through industry experience of the potential for installing Borg-Warner swing check valve internals backwards. However, adequate steps were not taken to prevent a similar event from occurring at Diablo Canyon Power Plant. Because this failure to promptly identify and correct conditions adverse to quality is of very low safety significance and has been entered into the corrective action program as Nonconformance Report (NCR) N0002164, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/03-06-01, Failure to identify and prevent check valve problems.

1R05 Fire Protection (71111.05)

.1 Routine Observations

a. Inspection Scope

The inspectors performed fire protection walkdowns to assess the material condition of plant fire detection and suppression, fire seal operability, and proper control of transient combustibles. The inspectors used Section 9.5 of the Final Safety Analysis Report (FSAR) Update as guidance. The inspectors considered whether the suppression equipment and fire doors complied with regulatory requirements and conditions specified in Procedures STP M-69A, “Monthly Fire Extinguisher Inspection,” Revision 33, STP M-69B, “Monthly CO2 Hose Reel and Deluge Valve Inspection,” Revision 14, STP M-70C, “Inspection/Maintenance of Doors,” Revision 8, and OM8.ID4, “Control of Flammable and Combustible Materials,” Revision 10. Specific risk-significant areas inspected included:

- Units 1 and 2 Turbine Building
- Units 1 and 2 Switchgear Rooms of the Auxiliary Building
- Units 1 and 2 Intake Structure

b. Findings

No findings of significance were identified.

.2 Fire Drill

a. Inspection Scope

On April 30, 2003, at 10:54 p.m., operators received an overcurrent trip for Unit 1 condensate Pump 1-3 because of a fire in the motor. The turbine building watch subsequently reported heavy smoke and flames coming from the motor of condensate Pump 1-3 at 11:04 p.m. The fire alarm was sounded and the first responder, the senior control operator (SCO) was dispatched to the scene. The SCO initially attempted to extinguish the fire using a hand-held fire extinguisher, and this effort was unsuccessful. The SCO then employed a large portable dry chemical unit, which was successful and the fire was out by 11:09 p.m. The fire brigade arrived at the scene shortly after the fire was out and established a reflash watch in the vicinity of condensate Pump 1-3. Operators racked out the breaker for condensate Pump 1-3 as a contingency.

Because of the heavy smoke in the turbine building, the shift manager evacuated the turbine building. Smoke was removed by the turbine building ventilation, and access was restored to the turbine building at 12 a.m. Because the fire was extinguished within 15 minutes of fire fighting actions, entry into the emergency plan was not necessary.

The inspector responded to the site and walked down the panels, reviewed operator logs and event statements, toured the turbine building, and took pictures of the damaged pump. In addition, the inspectors reviewed the fire incident report that provided a detailed description of the event and fire fighting efforts.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

Semi-Annual Inspection

a. Inspection Scope

The inspectors reviewed the internal flood protection measures for Unit 2 to ensure that Pacific Gas and Electric Company had taken adequate precautions to mitigate consequences to risk-significant structures, systems, and components. The inspectors reviewed Chapter 3 of the FSAR Update and Calculation F.4, “PRA Internal Floods Analysis,” Revision 1, to support the inspection effort. The inspectors toured the Unit 2 turbine building and reviewed the following work orders as part of the inspection:

- R0204626 on January 2, 2002
- R0204627 on January 2, 2002
- R0225335 on July 24, 2002
- R0227264 on November 12, 2002

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

Annual Inspection

a. Inspection Scope

The inspectors reviewed the inspection results of the Unit 2 residual heat removal heat exchangers. The inspectors reviewed design information found in Chapter 5 of the FSAR Update and verified test data obtained from Procedure ISI VT 2-1, “Report of Section XI Pressure Test,” Revision 6.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Quarterly Inspection

a. Inspection Scope

The inspectors witnessed operator performance in the simulator during routine training and requalification examinations. The inspectors verified the crew’s ability to meet the objectives of the training scenario, and attended the post-scenario critique to verify that crew weaknesses were identified and corrected by Pacific Gas and Electric Company staff. On June 19, 2003, the inspectors observed a simulator scenario associated with loss of a charging pump, a letdown system leak and a loss-of-offsite power coincident with a loss-of-coolant accident.

The inspectors used Procedures AP-17, "Loss of Charging," Revision 23, AP-18, "Letdown Line Failure," Revision 7, EOP E-0, “Reactor Trip or Safety Injection,” Revision 27, and EOP E-1, “Loss of Reactor or Secondary Coolant,” Revision 18, to support the inspection activities.

b. Findings

No findings of significance were identified.

.2 Biennial Inspection

a. Inspection Scope

The inspectors: (1) evaluated examination security measures and procedures for compliance with 10 CFR 55.49; (2) evaluated Pacific Gas and Electric Company’s sample plan for the written examinations in compliance with 10 CFR 55.59 and NUREG-1021, as referenced in the facility requalification program procedures; and (3) evaluated maintenance of license conditions in compliance with 10 CFR 55.53 by review of facility records (medical and administrative), procedures, and tracking systems for licensed operator training, qualification, and watchstanding. In addition, the inspectors reviewed remedial training and examinations for examination failures in compliance with facility procedures and responsiveness to address areas failed.

Furthermore, the inspectors: (1) interviewed six personnel (three operators, two instructors/evaluators, and a training supervisor) regarding the policies and practices for administering examinations; (2) observed the administration of four dynamic simulator scenarios to two requalification crews by facility evaluators, including an operations department manager, who participated in the crew and individual evaluations; and (3) observed two facility evaluators administer five job performance measures, including two in the control room simulator in a dynamic mode, and three in the plant under simulated conditions. Each job performance measure was observed being performed by an average of four requalification candidates.

The inspectors reviewed the remediation process for three individuals, one of which involved a written examination failure, one a simulator examination failure, and one periodic weekly quiz failure. The inspectors also reviewed the results of the annual licensed operator requalification operating examinations for 2002 and 2003. The results of the examinations were also reviewed to assess Pacific Gas and Electric Company’s appraisal of operator performance and the feedback of that performance analysis to the requalification training program. Inspectors also observed the examination security maintenance during the examination week.

Additionally, the inspectors assessed the Diablo Canyon Unit 1 plant-referenced simulator in compliance with 10 CFR 55.46 using Baseline Inspection Procedure IP-7111.11 (Section 03.11). The inspectors assessed the adequacy of the simulation facility (simulator) for use in operator licensing examinations and for satisfying experience requirements as prescribed in 10 CFR 55.46, “Simulation Facilities.”

The inspectors reviewed a sample of simulator performance test records (i.e., transient tests, surveillance tests, malfunction tests, and scenario-based tests), simulator work request records, and processes for ensuring simulator fidelity commensurate with 10 CFR 55.46. The inspectors reviewed selected simulator configuration reports generated by Pacific Gas and Electric Company that did not result in changes to the configuration of the simulator to assess the responsiveness of Pacific Gas and Electric Company’s simulator configuration management program. The simulator configuration reports included: incorrect response to safety injection pump discharge pressure, incorrect nuclear instrumentation response, incorrect main condenser pressure and temperature response during tube leaks, incorrect response to heater drain tank level changes, incorrect containment pressure response on small break loss of coolant accident, and incorrect response of reactor building pressure on loss of offsite power. The inspectors also interviewed members of Pacific Gas and Electric Company’s simulator configuration control group as part of this review.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed Pacific Gas and Electric Company’s Maintenance Rule implementation for equipment performance problems. The inspectors assessed whether the equipment was properly placed into the scope of the rule, whether the failures were properly characterized, and whether goal setting was recommended, if required. Procedure MA1.ID17, “Maintenance Rule Monitoring Program,” Revision 10, was used as guidance. The inspectors reviewed the following action request:

- A0579969, “Maintenance Rule Performance Goal Setting Review,” for Unit 2 Steam Generator Tube Integrity (Unit 2)

b. Findings

No findings of significance were identified.

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

.1 Risk Assessments

a. Inspection Scope

The inspectors reviewed daily work schedules and compensatory measures to confirm that Pacific Gas and Electric Company had performed proper risk management for routine work. The inspectors considered whether risk assessments were performed according to their procedures and Pacific Gas and Electric Company had properly used their risk categories, preservation of key safety functions, and implementation of work controls. The inspectors used Procedure AD7.DC6, "On-line Maintenance Risk Management," Revision 7, as guidance. The inspectors specifically observed the following work activities during the inspection period:

- Unit 1, Condensate Pump 1-3 Motor Replacement and AFW System Level Control Valve, FW-1-LCV-111, Repairs on April 29, 2003

- Unit 2, AFW System Level Control Valve, FW-2-LCV-113, repairs and SI Pump 2-2 coupling maintenance on May 7, 2003

- Unit 2, Battery Charger 2-1 repairs, condensate booster Pump 2-3 preventive maintenance concurrent with a California Independent System Operator Stage 1 Grid Emergency on May 28, 2003

b. Findings

No findings of significance were identified.

.2 Emergent Work

a. Inspection Scope

The inspectors observed emergent work activities to verify that actions were taken to minimize the probability of initiating events, maintain the functional capability of mitigating systems, and maintain barrier integrity. The scope of work activities reviewed includes troubleshooting, work planning, plant conditions and equipment alignment, tagging and clearances, and temporary modifications. The following activities were observed during this inspection period:

- Unit 2, Corrective maintenance associated with AFW Check Valve FW-2-377 and Main feedwater Pump 2-2 Coupling on April 3, 2003

- Unit 2, main generator hydrogen radial seal leak on April 7, 2003

b. Findings

No findings of significance were identified.

1R14 Personnel Performance Related to Nonroutine Plant Evolutions and Events (71111.14)

.1 Unit 1, Automatic Control Rod Insertion Due to Wrong Lifted Lead

a. Inspection Scope

On March 20, 2003, automatic rod motion was detected by operators due to a failure of the control input associated with PT-505, First Stage Turbine Pressure Transmitter. Bank D control rods inserted 13 steps into the core and reactor power decreased approximately 2 percent before operators placed rod control into manual. This event was documented in AR A0578997 and NCR N0002163. The inspectors reviewed operator and other Pacific Gas and Electric Company personnel actions prior to, during, and following the event.

b. Findings

Introduction. A Green self-revealing NCV was identified for the failure to accurately document design changes to reactor protection set cabinets, as required by 10 CFR Part 50, Appendix B, Criterion V. This failure resulted in unexpected control rod insertion.

Description. On March 20, 2003, control room operators for Unit 1 experienced automatic inward rod motion. The operators observed that pressure indicator PI-505, 1st stage main turbine pressure, was reading zero and assumed that pressure Transmitter PT-505 had failed low. First stage main turbine pressure is an input to the automatic rod control system, and if it fails low, it causes control rods to begin stepping into the reactor core. To stop the inward rod motion, operators placed rod control in manual, and maintenance personnel began to troubleshoot PT-505.

When troubleshooting PT-505, maintenance personnel noticed that an open circuit existed between PT-505 and the automatic rod control system. Maintenance personnel had been working in the reactor protection set cabinets to install humidity detection equipment. During equipment installation, maintenance personnel lifted leads that were located at Terminals 10 and 11, Block TBD, Rack 24. While the leads appeared to be spare wires on the drawings, there was a jumper between Terminals 10 and 11. The jumper, and the suspected spare wires, were part of the circuit between PT-505 and the automatic rod control system. Neither Drawing 663222, “Rack No. 24 Field Terminal Wiring,” Sheet 64, Revision 8, or Drawing 445629, “Process Control Racks – Control Group 2 ”, Sheet 1, Revision 12, revealed the jumper between Terminals 10 and 11. The jumper had been installed in 1989 during the digital feedwater control system installation.

The inspectors determined that there was a failure to reflect the jumper, and active use of Terminals 10 and 11, in safety-related drawings. The failure to update drawings after a design change and the failure of maintenance personnel to verify the function of the leads that were being lifted, resulted in an unplanned plant transient. The reduction in reactor power by approximately 2 percent did not impact safety, since operators and plant equipment responded in a timely and expected manner.

Analysis. The deficiency associated with this event is the failure to reflect design changes in appropriate drawings, which contributed to unexpected inward control rod motion. Using Example 4.b of Inspection Manual Chapter 0612, Appendix E, the finding is greater than minor since maintenance personnel performed activities with the deficient drawings and without verifying the function of the leads, caused a small plant transient. The finding, which is under the initiating events cornerstone, was of very low safety significance since operators appropriately mitigated the transient in a timely manner. Also, the transient was not severe enough to challenge the capability of the plant's mitigating equipment. The finding was reviewed against the initiating event screening criteria documented in Inspection Manual Chapter 0609, Appendix A, Attachment 1, SDP (Significance Determination Process) Phase 1 Screening Worksheet for IE (Initiating Event), MS (Mitigating Systems) and B (Barrier) Cornerstones. The finding is of very low safety significance because the condition did not contribute to a loss of coolant initiator, would not contribute to the likelihood a mitigating system would not be available and did not involve an external event initiator. In addition, the operators responded in a timely, appropriate manner and mitigating equipment was not challenged by the transient .

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that instructions, procedures, and drawings shall include appropriate quantitative and qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to the above, the jumper between Terminals 10 and 11, Block TBD, was not shown in Drawing 663222, Sheet 64, Revision 8, and Drawing 445629, Sheet 1, Revision 12. The failure to document the jumper contributed to unplanned control rod inward motion. Because this failure to document the jumper is of very low safety significance and has been entered into the corrective action system as AR A0578997 and NCR N0002163, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/03-06-03, Failure to Maintain Design Drawings to Prevent Inward Rod Motion.

.2 Inadvertent Unit 2 AFW Actuation

a. Inspection Scope

On April 8, 2003, at 2:53 p.m., AFW Pump 2-3 automatically started on a valid signal when the solid-state protection system was placed into service and Steam Generator 2-1 level was below the AFW system actuation setpoint. At the time the actuation occurred, Unit 2 was in Mode 5 (Cold Shutdown) and decay heat was being removed by the residual heat removal system. Immediate corrective actions included filling Steam Generator 2-1 above the AFW system actuation setpoint and securing AFW Pump 2-3. This event was documented in AR A0580471.

The inspectors reviewed operator logs and procedures and interviewed operators in order to evaluate operator actions. The inspectors used Procedure STP I-38-AB.3, "SSPS Train A&B Return to Service After Testing/Maint. In Modes 5, 6, or Defueled," Revision 3.

b. Findings

No findings of significance were identified.

.3 Unit 2, Inadvertent Power-Operated Relief Valve (PORV) Opening

a. Inspection Scope

On April 19, 2003, during a channel operability test, one PORV, RCS-2-PCV-456, opened unexpectedly. The inadvertent PORV opening reduced reactor coolant system pressure from the normal 2235 psig to 2165 psig in 14 seconds. This was documented in AR A0581421. The inspectors reviewed operator logs, plant computer data, and strip charts to determine what occurred and how the operators responded, and to determine if the response was in accordance with plant procedures. The inspector also evaluated the response of plant equipment.

b. Findings

Introduction. A Green self-revealing NCV was identified for the failure to use the latest revision of a surveillance procedure, which resulted in PORV, RCS-2-PCV-456, opening during testing.

Description. On April 19, 2003, during a channel operability test on Unit 2, RCS-2-PCV-456 unexpectedly opened and caused reactor coolant system pressure to drop from its normal operating pressure of 2235 psig to 2165 psig. Operators were alerted to the condition when alarms indicated that the PORV was open and the pressurizer relief tank pressure had increased. As operators reached the vertical control board to close RCS-2-PCV-456, the PORV automatically closed when it reached the 2185 psig interlock setpoint for closing the PORV on low pressure. The pressure drop occurred in 14 seconds and operators were able to restore pressure to its normal status in less than 10 minutes. Other than the pressure transient, no other impact to Unit 2 was observed. Alarms, plant equipment, and operators responded appropriately.

Upon review of the transient, Pacific Gas and Electric Company personnel determined that the wrong revision of the procedure test had been used during the channel operability test. Procedure STP I-36-S2R10, “Protection Set II, Rack 10 Channels Operational Test,” Revision 9, was used during the test, and it was the current revision before Refueling Outage 2R11. During 2R11, the control circuitry for Unit 2 PORVs was modified to support work to make another PORV, RCS-2-PCV-474, safety-related. Due to the control circuit modifications, the controller for RCS-2-PCV-456 now had to be taken to the “close” position during channel operability tests to prevent it from opening. Prior to 2R11, RCS-2-PCV-456 was left in the “auto” position for this particular channel operability test. Revision 10 had been generated for Procedure STP I-36-S2R10, but Pacific Gas and Electric Company personnel used Revision 9 due to a failure to adequately assemble and verify the maintenance document package prior to initiating work.

Analysis. The deficiency associated with this event was the use of an incorrect surveillance test procedure revision, which caused a PORV to open unexpectedly. This finding impacted the Initiating Event Cornerstone and is greater than minor because it had an actual impact of opening a relief valve. Opening a relief valve is considered a precursor to a nonsignificant event (i.e., relief valve stuck-open). Using Inspection Manual Chapter 0609, “Significance Determination Process,” Phase 1 Screening Worksheet, this finding is considered a primary system loss-of-coolant-accident initiator, requiring an SDP Phase 2 Analysis. Using SDP Phase 2 notebook, “Risk-Informed Inspection Notebook For Diablo Canyon Power Plant – Units 1 and 2,” Revision 1, the deficiency is assumed to impact the “Stuck-Open PORV” accident initiator only. The condition existed for less than 3 days. The inspectors considered that performance of the surveillance test would cause the valve to open and therefore increased the likelihood of the PORV sticking open in the Phase 2 analysis. All mitigating equipment, including the PORV low pressure interlock and PORV block valve, was assumed operable, and operators were able to respond to a potential event. The finding was determined to be of very low safety significance using the SDP Phase 2 Analysis.

Enforcement. Technical Specification 5.4.1.a requires written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A. Regulatory Guide 1.33, Appendix A, Item 8.b.1.l provides that procedures be implemented for reactor protection system tests and calibrations. Contrary to the above, the correct revision of Procedure STP I-36-S2R10 was not implemented on April 19, 2003, which resulted in an inadvertent opening of a PORV during testing. Because this failure to implement the correct revision of the surveillance procedure is of very low risk significance and has been entered into the corrective action system as AR A0581421, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/03-06-01, Failure to Implement Correct Revision of Procedure Results in Power-Operated Relief Valve Opening.

.4 Fire In Condensate Pump 1-3 Motor

a. Inspection Scope

At 10:54 p.m., on April 30, 2003, operators received an overcurrent trip for Unit 1 condensate Pump 1-3. Condensate booster Pump 1-3 also tripped. The standby pumps (condensate/condensate booster Pumps 1-2) started automatically and restored condensate flow immediately. Operators entered the applicable abnormal procedures and monitored the Unit 1 response to the transient. The operators determined that a ramp down of Unit 1 was not necessary when the plant stabilized.

The turbine building watch subsequently reported heavy smoke and flames coming from the motor of condensate Pump 1-3 at 11:04 p.m. The fire alarm was sounded and the fire brigade responded.

Because of the heavy smoke in the turbine building, the shift manager evacuated the turbine building. Smoke was removed using the turbine building ventilation, and access was restored to the turbine building at 12 a.m. Because the fire was extinguished within 15 minutes of fire fighting actions, entry into the emergency plan was not necessary.

The inspectors responded to the site and walked down the control room panels to determine that the plant was stable. In addition, the inspectors toured the Unit 1 spaces to determine if any collateral damage that would impede plant operations existed. The inspectors reviewed operator statements and Pacific Gas and Electric Company's review of the event.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed operability evaluations and supporting documents to determine if the associated systems could meet their intended safety functions despite the degraded status. The inspectors reviewed the applicable Technical Specifications, Codes/Standards, and FSAR Update sections in support of this inspection. The inspectors reviewed the following AR's and operability evaluations:

- Unit 2 Power Range Detector N-42 (AR's A0579398, A0579546, and A0579971)
- Unit 2 RCS Flow and Steam Header Pressure (AR A0581408)
- Unit 2 AFW Pump 2-2 Recirculation Line flow oscillations (AR A0580182)
- Unit 2 DEG 2-2 slow speed rise time (AR A0580786)

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds

a. Inspection Scope (71111.16)

The inspectors reviewed Pacific Gas and Electric Company's documented actions in which degraded conditions or changes to accident analyses required additional operator action beyond that credited in the design basis to compensate for these conditions. Pacific Gas and Electric Company tracked these conditions as operator burdens or operator workarounds.

Pacific Gas and Electric Company defined an operator burden as a manual action taken to compensate for degraded equipment that affected normal operation of a unit. There were13 operator burdens.

An operator workaround was defined as a manual action taken to compensate for a degraded condition required for response to abnormal or emergency operating procedures. Pacific Gas and Electric Company had 10 operator workarounds. The inspectors assessed the cumulative affect of the operator workarounds to determine if the operators would be overly taxed with working around numerous degraded conditions that would complicate an abnormal or emergency condition.

The inspectors reviewed Pacific Gas and Electric Company's program for tracking the operator workarounds and restoring the applicable systems to full qualification, to determine if Pacific Gas and Electric Company appropriately managed these items. None of the operator workarounds involved risk-significant actions.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

.1 Biennial Review

a. Inspection Scope

The inspectors reviewed procedures governing plant modifications to evaluate the effectiveness of the programs for implementing modifications to risk-significant systems, structures, and components, such that, these changes did not adversely affect the design and licensing basis of the facility. The inspectors reviewed seven permanent plant modification packages (design change packages or notices) and six maintenance modification packages, including associated documentation such as review screens and safety evaluations, to verify that they were performed in accordance with regulatory requirements and plant procedures. Procedures and plant modifications reviewed are listed in the attachment to this report.

The inspectors interviewed the cognizant design and system engineers for the identified modifications as to their understanding of the modification packages. The inspectors evaluated the effectiveness of Pacific Gas and Electric Company's corrective action process to identify and correct problems concerning the performance of permanent plant modifications. In this effort, the inspectors reviewed the corrective action documents identified in the attachment to this report and the subsequent corrective actions pertaining to Pacific Gas and Electric Company-identified problems and errors in the performance of permanent plant modifications. In conjunction with review of the corrective action process, the inspectors reviewed Pacific Gas and Electric Company's internal quality services audits and assessments conducted during the past two years to determine the effectiveness of their oversight and subsequent actions resulting from the audits and assessments.

b. Findings

No findings of significance were identified.

.2 Annual Review

a. Inspection Scope

Unit 1 Main Feedwater Pump Speed Control System was upgraded due to electronic component aging and discontinued vendor support. The new speed control system utilized a high integrity, fault-tolerant controller with triple-redundant microprocessors. Additional upgrades included new governor valve servo positioners, with an independent system to deliver oil to the positioners. The modification was necessary to prevent loss of the main feedwater pumps, which could lead to a reactor trip.

The inspectors reviewed Design Change Package J-049419, Revision 0, which described the modification. The inspectors verified that: (1) control signals were appropriate under normal, abnormal, and accident conditions, (2) the modification would not cause a system response that was not previously analyzed or expected, (3) in terms of material, environmental, and seismic concerns, it was compatible with surrounding safety-related equipment, (4) its impact on the vital electrical distribution system was acceptable, and (5) operators understood and appropriately operated the system.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed postmaintenance tests for selected risk-significant systems to verify their operability and functional capability. As part of the inspection process, the inspectors witnessed and/or reviewed the postmaintenance test acceptance criteria and results. The test acceptance criteria was compared to the Technical Specifications and the FSAR Update for the Diablo Canyon Power Plant. Additionally, the inspectors verified that the test was adequate for the scope of work, the test was performed as prescribed, jumpers and test equipment were properly removed after the test, and test equipment range, accuracy, and calibration were consistent for the application. The following are selected corrective maintenance activities reviewed by the inspectors:

- Unit 2, AFW Level Control Valve FW-2-LCV-113, following packing replacement on May 7 (Work Order R0246596)
- Unit 2, Positive Displacement Pump 2-3, following replacement of Relief Valve CVCS-2-RV-8116 on May 14 (Work Order R0223095)
- Unit 2, Battery Charger 2-1, following replacement of capacitors on May 29 (Work Order R02281164)
- Unit 2, Boric Acid Transfer Pump 1-1, following a routine motor and pump overhaul on May 31 (Work Order R0243691)
- Unit 2, Control Room Ventilation System, following replacement of Compressor CP-38 on June 6 (Work Order R0246515)

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors evaluated several routine surveillance tests to determine if Pacific Gas and Electric Company complied with the applicable Technical Specification requirements to demonstrate that equipment was capable of performing its intended safety functions and operational readiness. The inspectors performed a technical review of the procedure, witnessed portions of the surveillance test, and reviewed the completed test data. The inspectors also considered whether proper test equipment was utilized, preconditioning occurred, test acceptance criteria agreed with the equipment design basis, and equipment was returned to normal alignment following the test. The following tests were evaluated during the inspection period:

- Procedure STP P-CCW-22, “Routine Surveillance Test of Component Cooling Water Pump 2-2,” Revision 8, on April 19 for Unit 2
- Procedure STP P-RHR-12, “Routine Surveillance Test of RHR Pump 1-2,” Revision 13, on May 8 for Unit 1
- Procedure STP M-9A, “Diesel Engine Generator Routine Surveillance Test,” Revision 64, on May 8 for Unit 2
- Procedure STP M-74, “Auto Start of the ASW Pumps on Low Pressure,” Revision 5, on May 20 for Unit 2
- Procedure STP P-CCP-12, “Routine Surveillance Test of Centrifugal Charging Pump 1-2,” Revision 13, on June 9, 2003 for Unit 1

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed temporary plant modifications that could potentially impact the mission of important safety systems. Temporary plant modifications include jumpers, lifted leads, temporary systems, repairs, design modifications, and procedure changes which can introduce changes to plant design or operations. Inspection activities include a review of the temporary modification impact on: (1) operability of equipment, (2) energy requirements, (3) material compatibility, (4) structural integrity, (5) environmental qualification, (6) response time, and (7) logic and control integration. The inspectors also verified the design and alignment of safety systems when the temporary modifications were no longer needed. The following temporary modification was reviewed during this inspection period:

- Units 1 and 2, Jumper Installed between Breakers SVU-15 and EVCLR-15 to support Refueling Outage 2R11 per AR A0564970
- Unit 2, Temporary Gage PT-5 installed on Component Cooling Water Heat Exchanger 2-1 per AR A0569136

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector performed an in-office review of Revision 4, Changes 2 and 3, to the Diablo Canyon Emergency Plan against the previous revision and 10 CFR 50.54(q) to determine if the revision decreased the effectiveness of the plan. Change 2 affected three sections of the plan. Section 4, Emergency Action Level 30 (Unusual Event), was changed to make the security based Emergency Action Level applicable at all plant operating modes vice only Modes 1 through 4. Section 6 was changed to update the evacuation time assessment, and Section 10 was changed to update plan references. Change 3 removed the control room assistant position from the on shift emergency response staffing. The duties of that position were reassigned to the second on shift balance of plant operator, who was previously unassigned. The total number of assigned on shift emergency response staff and functions were unchanged.

b. Findings

No findings of significance were identified.

1EP6 Emergency Preparedness Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors witnessed the emergency preparedness drill conducted on May 28, 2003. The challenging scenario consisted of a security event that resulted in a Site Area Emergency from a loss of offsite power and high pressure injection. The inspectors observed Pacific Gas and Electric Company's performance in the simulator, and the technical support center. The inspectors also attended Pacific Gas and Electric Company's self-critique of the drill. The following procedures were used to evaluate the drill performance:

- EP G-1, "Emergency Classification and Emergency Plan Activation," Revision 32
- EP G-2, "Activation and Operation of the Interim Site Emergency Organization," Revision 26
- EP G-3, "Notification of Off-Site Agencies and Emergency Response Organization Personnel," Revision 40

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Reactor Safety Performance Indicator Verification

a. Inspection Scope

The inspectors reviewed the following performance indicators for the period from the second quarter of 2002 through the first quarter of 2003 to assess the accuracy and completeness of the indicator. The inspectors reviewed plant operating logs and Pacific Gas and Electric Company monthly operating reports to support this inspection. The inspectors used NEI 99-02, "Regulatory Assessment Performance Indicator Verification," Revision 2, as guidance for this inspection.

- Units 1 and 2 High Pressure Safety Injection Availability
- Units 1 and 2 Residual Heat Removal Availability
- Units 1 and 2 Diesel Engine Generator Availability
- Units 1 and 2 AFW Availability

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Unit 1 Diesel Engine Generator (DEG) 1-3

a. Inspection Scope

The inspectors reviewed the performance and maintenance activities associated with the DEG 1-3 for the past year. In particular, the inspectors reviewed the following DEG events that had direct or indirect impact on DEG 1-3:

- August 31, 1998, DEG 1-1 failed its surveillance test with respect to achieving required voltage within 13 seconds (AR A0467444)

- February 27, 1999, DEG 1-1 failed its surveillance test with respect to achieving required voltage within 13 seconds (Quality Evaluation Q0012109)

- August 12, 2002, DEG 1-3 failed its surveillance test with respect to achieving required voltage within 13 seconds (AR A0576094)

- February 23, 2003, DEG 1-3 failed its surveillance test with respect to achieving rated voltage within 13 seconds (AR A0576094)

The inspectors verified that complete and accurate identification of the problem was made in a timely manner, commensurate with its significance and ease of discovery. They also evaluated issues regarding maintenance effectiveness, operability, reportability, generic implications, and extent of condition. For identified problems, the inspectors reviewed their classification and prioritization, root and contributing causes, and corrective actions.

b. Findings

Introduction. A Green NCV was identified for the failure to identify and correct a condition adverse to quality, in accordance with 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions.” Specifically, DEG 1-3 remained in service for over 6 months with a faulty automatic voltage regulator card. This resulted in diesel engine generator failures, in that it did not achieve its required voltage rise time.

Description. On 6 occasions (2 during troubleshooting), slow voltage rise times were experienced on DEG 1-1 and DEG 1-3. The slow voltage rise times were observed from August 1998 to February 2003 while performing surveillance tests or troubleshooting. The DEGs are required by Technical Specification Surveillance Requirement 3.8.1.7 to achieve between 3785 V and 4400 V in less than 13 seconds.

On August 31, 1998, DEG 1-1 experienced a slow voltage rise time of 14.9 seconds. During troubleshooting on September 18, DEG 1-1 again demonstrated a slow voltage rise time of 19.8 seconds. Using windowgraph data, the voltage rise appeared to slow at approximately 2080 V, which is near the point where the Field Flash Cutout (K3) relay should energize and remove the field flash. Maintenance personnel inspected the K3 relay and found one terminal 5 turns loose. This terminal was tightened and DEG 1-1 was returned to service.

On February 27, 1999, DEG 1-1 failed its surveillance test due to a slow voltage rise time of 20.4 seconds. Maintenance and engineering staff ran several instrumented test runs and inspected various generator voltage control components to identify the problem. Engineering staff suspected a faulty K3 relay and had it replaced. Since engineering staff could not test the automatic voltage regulator card, it was replaced and sent to the vendor for testing. As discussed in the root cause analysis of NCR N0002159, “DEG 1-3 Failure to Achieve TS [Technical Specification]-Required Voltage and Frequency,” Revision 0 Draft (June 10, 2003), the failure analysis report was submitted to engineering staff from the vendor. However, the lessons learned were not communicated or retained by the staff. Following the replacement of the K3 relay and the automatic voltage regulator card, no additional failures of DEG 1-1 to achieve its voltage rise time were experienced.

On August 12, 2002, DEG 1-3 demonstrated a slow voltage rise time of approximately 25 seconds during a surveillance test. Following this test, Pacific Gas and Electric Company staff performed a number of test runs and inspections, but could not get DEG 1-3 to repeat the problem. Engineering staff determined the most likely cause of the problem to be the K3 relay and had it replaced. On February 23, 2003, DEG 1-3 again demonstrated a slow voltage rise time of approximately 53 seconds. Initially, engineering staff suspected the K3 relay. However, engineering staff tested the assumption of a faulty K3 relay and found that it could not be the cause of the problem. Troubleshooting did not reveal any degradation in any other electrical or mechanical components that could cause DEG 1-3 to have a slow voltage rise time. Since the automatic voltage regulator card could not be tested, maintenance personnel replaced the card, and it was sent to a laboratory for analysis. According to MPR Report, "Failure Analysis of Basler Circuit Card Model 32101-109," May 2, 2003, the laboratory could not recreate the failure with the card, but they did identify several cold solder joints for a magnetic amplifier on the circuit card. Laboratory personnel believed that under the right conditions, the cold solder joints could cause the slow voltage rise time. Pacific Gas and Electric Company and laboratory personnel have planned additional tests to verify that the cold solder joints could cause the slow voltage rise time.

As identified in NCR N0002159, Pacific Gas and Electric Company staff failed to identify and correct the faulty automatic voltage regulator card in a timely manner. The inspectors observed two weaknesses which lead to the untimely replacement of the automatic voltage regulator. First, Pacific Gas and Electric Company staff assumed a problem with the K3 relay without adequately verifying their assumptions or broadening the troubleshooting process to consider other possibilities. Second, Pacific Gas and Electric Company staff did not appropriately receive, review, and apply the lessons learned from DEG 1-1 failures.

While reviewing the DEG 1-3 events, the inspectors observed that a sound operability determination for the other DEGs, with regards to automatic voltage regulator cards, was not documented. Pacific Gas and Electric Company staff stated that operability of the other DEGs had been covered in AR A0576110 on February 28, 2003. Pacific Gas and Electric Company staff also stated that information on the cold solder joints, when received from the laboratory, was evaluated by the Technical Review Group, discussed with operators, and documented in NCR N0002159. Operators determined that no formal prompt operability analysis was needed. The inspectors reviewed AR A0576110 and found that it discussed the basis for returning DEG 1-3 back to service after its failed surveillance test on February 23, 2003. While the AR did mention that the other two DEGs for Unit 1 had been test run with no problems, it did not discuss the operability of the other DEGs with respect to the automatic voltage regulator cards. The inspectors also reviewed NCR N0002159 and observed that the DEG system engineer had documented that he had a conversation with operators and they mutually agreed that there was no current operability concern. The inspectors determined that the documentation in AR A0576110 and NCR N0002159 did not meet the expectations of Procedure OM7.ID12, “Operability Determination,” Revision 6, and Generic Letter 91-18, “Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions,” Revision 1. Specifically, Inspection Manual Chapter Part 9900, “Operable/Operability: Ensuring the Functional Capability of a System or Component,” October 31, 1991, which is referenced by Generic Letter 91-18, states that whenever the ability of a system or structure to perform its specified function is called into question, operability must be determined from a detailed examination of the deficiency. With respect to the automatic voltage regulator card, the inspectors determined that an operability determination should have been made with respect to the other DEGs since they have cards that are of similar vintage and age. The operability determination should also have addressed design basis accidents, such as a seismic event, that could aggravate any cold solder joints. The inspectors determined that there was no current DEG operability issues with respect to the automatic voltage regulator cards.

Analysis. The deficiency associated with this finding is a failure to promptly identify and correct a condition adverse to quality, which lead to DEG 1-3 being placed into service with a faulty automatic voltage regulator card. The finding impacted the mitigating system cornerstone and was more than minor when assessed using Inspection Manual Chapter 0612, Appendix E, Example 4.f. Similar to the example, DEG 1-3 was inoperable from August 31, 2002, to February 23, 2003, which is the time period that the fault in the automatic voltage regulator card was known to exist. Using SDP Phase I Worksheet in Inspection Manual Chapter 0609, the inspectors determined that there was an actual loss of a safety function for greater than the DEGs Technical Specification allowed outage time, which required an SDP Phase 2 analysis.

The assumptions used to evaluate this condition were discussed between the inspectors, senior reactor analysts and NRR staff. The condition resulted in an impact on DEG 1-3 but not the equipment it supports since DEG 1-3 only exhibited a slow start versus no start as a result of the degraded voltage regulating card. The NRC staff determined that the sequences involving a loss of offsite power with a large break LOCA, a large break LOCA with a subsequent loss of offsite power and external events (seismic) should be evaluated. The components powered by DEG 1-3 were considered for their impact on the above sequences. One charging pump, AFW pump, and safety injection pump associated with DEG 1-3 could have been delayed in their start times (on the order of seconds). However, the residual heat removal pumps, which are powered from DEGs 1-1 and 1-2 on a loss of offsite power were not effected. No change in the initiating event frequency for loss of offsite power was made because the DEG would provide power to its vital bus if needed. The emergency AC (EAC) safety function was credited as a single train system to capture the condition associated with DEG 1-3 with credit for recovery. The SDP worksheet for loss of offsite power and loss of Vital 4.16kV AC Bus F (LEACF) was not evaluated as power to Bus F would be provided. Similar criteria was applied for seismic considerations. The safety systems needed to mitigate potential effects of a seismic event on the plant would have been available. The result of the SDP Phase 2 and external events evaluation was a finding of very low safety significance (Green).

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, states, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to the above, Pacific Gas and Electric Company's failure to promptly identify and correct the faulty automatic voltage regulator card on DEG 1-3 resulted in a condition where the DEG may not achieve the required voltage within the time specified by technical specifications. Because the failure to promptly identify and correct the faulty automatic voltage regulator card was determined to be of very low safety significance and has been entered into the corrective action program as NCR N0002159, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/03-06-04, Failure to Promptly Identify and Correct a Faulty Automatic Voltage Regulator Card.

.2 Cross-Reference to PI&R Findings Documented Elsewhere

Section 1RO4.4 of this report describes a finding for the failure to take timely corrective action to prevent continued plant operation with multiple degraded check valves in the AFW system.

4OA3 Event Followup (71153)

.1 (Closed) Licensee Event Report (LER) 50-323/01-004-00: Technical Specification 3.4.10 not met during pressurizer safety valve testing.

On June 26, 2001, Pacific Gas and Electric Company identified that two of the three Unit 2 pressurizer safety valves had lift setpoints outside of the Technical Specification 3.4.10 tolerance. During routine surveillance testing at an offsite facility, the two out-of-tolerance pressurizer safety valves had lift setpoints that were 3.4 percent low and 2.8 percent high, while the Technical Specification 3.4.10 tolerance was +/- 1 percent. Pacific Gas and Electric Company adjusted the setpoints of the deficient pressurizer safety valves within tolerance, retested them, and returned them to service.

The inspectors reviewed this issue and determined that Pacific Gas and Electric Company fully complied with the Technical Specification requirements from the time of discovery of the condition. No other reasonable opportunity existed to identify this condition other than removal and offsite testing during a refueling outage. Therefore, the inspectors determined that no violation of NRC requirements occurred. The inspectors reviewed Pacific Gas and Electric Company corrective actions and determined that the actions to be reasonable. This LER is closed.

.2 (Closed) LER 50-275; 323/01-002-00: Unplanned diesel generator starts due to loss of startup power.

This LER describes an event on August 4, 2001, in which an explosion in a grounding transformer caused a loss of the startup transformers for both units, resulting in all of the diesel generators for both units (total of six) starting but not loading.

Inspector followup of this event was fully discussed in NRC Inspection Report 50-275; 323/2001-007. A finding of very low safety significance for this issue was identified in NRC Inspection Report 50-275; 323/2003-005. No additional information was provided in this LER that would alter the previous disposition of this issue. This item is closed.

.3 (Closed) LER 50-323/02-01-00: Fasteners failed due to stress corrosion cracking.

This LER describes an event in which fasteners on an atmospheric dump valve failed partially because of stress corrosion cracking and overtorquing. This issue was discussed fully in NRC Inspection Report 50-275:323/2002-004. A noncited violation of very low safety significance was identified. No new information was provided in this LER that would alter the previous disposition of the issue. This item is closed.

.4 (Closed) LER 50-275/02-03-00 and -01: Unanalyzed condition due to heavy load lifted over a restricted area.

This LER describes an event in which a turbine casing was lifted directly over the operable diesel generators. The lift height and weight of the load were in excess of the loading analysis of record. This issue was discussed fully in NRC Inspection Report 50-275; 323/2002-003. A noncited violation of very low risk significance was identified. No additional information was provided in this LER that would alter the previous disposition. This item is closed.

.5 (Closed) LER 50-323/03-06-00: Unit 2 Auxiliary Feedwater System Actuation Due to Personnel Error.

This LER describes an event in which AFW Pump 2-3 inadvertently actuated on a valid signal when the solid-state protection system was placed into service. Operators had failed to recognize the presence of logic for an automatic AFW system actuation prior to placing the solid-state protection system into service. This issue is fully discussed in the current report under Section 1R14.2. No findings of significance were identified. No additional information was provided in this LER that would alter the current disposition. This item is closed.

.6 (Closed) URI 50-323/03-05-02: Failure to Implement Outage Safety Management Control for Containment Closure.

Introduction. A Green NCV of Technical Specification 5.4.1.a was identified for the failure to promptly notify the shift foreman when it was determined that containment closure could not be established during reduced inventory operations because of an obstruction that prevented the fuel transfer tube isolation valve from being closed. Pacific Gas and Electric Company calculated that during a 2.5-hour period the fuel transfer tube could not be isolated, the reactor coolant system could potentially begin boiling within 22 minutes if shutdown cooling was lost. This was previously considered an unresolved item pending significance determination.

Description. On February 8, 2003, during testing of the Unit 2 fuel transfer cart, the cart became stuck in the closing path of fuel transfer tube isolation Valve SFS-2-50. A fitting in the cable retract mechanism became loose because it was installed improperly. Personnel performing this test were unaware that this task breached the containment boundary and the containment coordinator did not inform the shift foreman of the condition until 1.5 hours later. Approximately an hour later the shift foreman completed development of a contingency plan to restore containment closure capability in the event of a loss of residual heat removal. If a loss of residual heat removal had occurred during this time period, containment closure, using fuel transfer tube isolation Valve SFS-2-50, could not be met prior to core boiling as specified. Pacific Gas and Electric Company initiated AR A0574018 and placed this item into the corrective action program.

The inspectors identified that the pre-job briefings did not inform the workers that testing the fuel transfer cart involved breaching the containment boundary, and of the need to immediately inform the control room in the event that Valve SFS-2-50 could not be closed. In addition, Pacific Gas and Electric Company did not ensure that adequate contingencies were developed prior to beginning spent fuel transfer cart testing to ensure that containment closure capability could be restored in an expeditious manner if problems occurred.

Analysis. The inspectors determined that this issue affected the reactor safety strategic performance area, in the barrier integrity cornerstone. The finding was determined to be more than minor because the finding affected the barrier cornerstone objective to provide reasonable assurance that the containment protects from the release of radionuclides resulting from accidents or events. The inspectors reviewed the finding for the safety significance using Inspection Manual Chapter 0609, Appendix G, Shutdown Operations. Section IV to Containment Control Guidelines was considered and a Phase 2 and 3 analysis was determined to be appropriate because of the impact on the ability to isolate the fuel transfer canal. The draft guidance provided in Inspection Manual Chapter 0609, Appendix H - Containment Integrity Significance Determination Process, was utilized in the Phase 2 analysis, along with the oversight of a senior reactor analyst.

The initial conditions considered for the containment integrity SDP were the condition occurred within 8 days of the outage, the reactor vessel level was less than 23 feet from the top of the reactor vessel flange (POS 2), the reactor coolant system was vented, a robust mitigation capability was in place and the condition existed for less than 8 hours. Utilizing Table 6.4 , Phase 2 Risk Significance - Type B Findings at Shutdown (for POS 1/TW-E and POS 2/TW-E in which the finding occurs during the first 8 days of the outage) the finding is potentially white. Note 2, to Table 6.4, specifies that for Type B findings (does not effect core damage frequency) that exist for less than 8 hours, then the color of the finding is reduced by an order of magnitude. Using the containment integrity SDP the finding was determined to be of very low safety significance (Green).

The senior reactor analyst also reviewed the reactor plant initial conditions, fuel transfer canal configuration and mitigating strategies specified in Pacific Gas and Electric Company's outage plan. The analyst considered the mitigation factors that addressed potential large early release through the fuel transfer tube. The inspectors determined that the inability to close the fuel transfer tube did not increase the initiating event frequency for a loss of shutdown cooling during reduced inventory operations. Pacific Gas and Electric Company had procedures in place to address a loss of shutdown cooling that included gravity fill makeup to the reactor vessel through a safety injection cold leg injection line, and makeup capability using a safety injection or charging pump. Pacific Gas and Electric Company's procedures provided for the initiation of reactor vessel coolant makeup before the onset of reactor coolant system boiling. In addition, analysis of the fill rate using gravity feed or the safety injection or charging pumps would provide for coverage of the fuel transfer tube in less than two hours. The time to core uncovery, without shutdown cooling or makeup, was determined to be approximately 2 hours. Other large early release mitigating factors included the availability of the containment coolers and the fuel handling building ventilation and filtration system. Pressure in the containment would remain near atmospheric because of the relatively low energy released (relative to the containment design) from the initiating conditions and availability of containment coolers. Any radioactive material transported to the fuel handling building would be filtered through the fuel handling building ventilation system and monitored.

Based on Inspection Manual Chapter 0609, Appendix H - Containment Integrity Significance Determination Process and an independent Phase 3 review, the NRC staff concluded that the finding was of very low safety significance.

<u>Enforcement</u>. Technical Specification 5.4.1.a requires written procedures to be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A. Regulatory Guide 1.33, Appendix A, Item 3.f, specifies that procedures be implemented for the operation and shutdown of safety-related PWR systems including maintaining containment. Contrary to the above, Procedure AD8.DC54, Containment Closure," Revision 8, paragraph 5.1.4.b. requires in part, that if any hatch or the fuel transfer tube cannot be closed within the calculated time to boil, the shift foreman shall be informed. The NRC inspectors identified that

Pacific Gas and Electric Company had not informed the shift foreman in a timely manner, relative to the calculated time to boil, to ensure that the fuel transfer tube could be isolated in the event of a loss of shutdown cooling.

Because the failure to implement adequate outage safety control over containment closure was of very low safety significance and has been entered into the corrective action system as AR A0574018, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/03-06-05, Failure to Implement Outage Safety Management Control for Containment Closure.

40A4 Crosscutting Aspects of Findings

Section 1R14.1 of the report describes a human performance crosscutting issue where maintenance personnel performed activities using deficient drawings without adequately verifying the function of leads prior to lifting. This event occurred while implementing a design modification.

Section 1R14.3 of the report describes a finding that involved a human performance crosscutting issue for the failure to obtain the correct revision to a surveillance procedure. Maintenance personnel performed a surveillance test on a PORV, using the incorrect surveillance test revision that resulted in the PORV opening with the plant at 100 percent power.

Section 4OA3.6 of the report describes a human performance crosscutting issue involving plant personnel failing to promptly notify the shift foreman that containment closure could not be attained during reduced reactor coolant system inventory operation because of the fuel transfer cart blocking the fuel transfer tube.

40A5 Other

.1 Evaluation of Diablo Canyon Safety Condition in Light of Financial Conditions

a. Inspection Scope

Due to Pacific Gas and Electric Company's financial condition, Region IV initiated special review processes for Diablo Canyon. The resident inspectors continued to evaluate the following factors to determine whether the financial condition and power needs of the station impacted plant safety. The factors reviewed included: (1) impact on staffing, (2) corrective maintenance backlog, (3) corrective action system backlogs, (4) changes to the planned maintenance schedule, (5) reduction in outage scope, (6) availability of emergency facilities and operability of emergency sirens, and (7) grid stability (i.e., availability of offsite power to the switchyard, status of the operating reserves especially at the onset of rolling blackouts, and main generator Volt-Ampere reactive loading).

Additionally, the resident inspectors observed the energy supply and operating reserves available in the California market. Inspectors have also increased attention to areas such as employee morale, Pacific Gas and Electric Company activities, and specific technical issues.

b. Findings

No findings of significance were identified.

.2 Review of the Institute for Nuclear Power Operations (INPO) Annual Evaluation

On June 13, 2003, the inspectors reviewed the INPO Evaluation and Assessment report for Pacific Gas and Electric Company. The inspectors noted that the INPO evaluation was generally commensurate with NRC assessment of performance and that no significant safety issues requiring separate NRC followup were identified.

.3 (Closed) URI 50-275; 323/0206-02: Effect of Harmonics on Second Level Under-Voltage-Relay Accuracy

During a Safety System Design and Performance Capability inspection of Diablo Canyon Power Plant Units 1 and 2 (NRC Inspection Reports 50-275/02-06 and 50-323/02-06), the inspectors raised a question about whether Pacific Gas and Electric Company had considered the effects of harmonics on the second level under-voltage relays. Based on a further review, the inspectors concluded that regulations do not require Pacific Gas and Electric Company to account for the effects of harmonics. The inspectors also reviewed industry operational history and determined that such harmonics have never compromised safety or affected the calibration or functioning of these relays. Based on this further review, this URI is closed.

40A6 Management Meetings

Exit Meeting Summary

The resident inspection results were presented on July 3, 2003, to Mr. James R. Becker, Vice President - Diablo Canyon Operations and Station Director, and other members of Pacific Gas and Electric Company management. Pacific Gas and Electric Company acknowledged the findings presented.

On May 6, 2003, the inspector presented the preliminary inspection results to Mr. Mark Lemke, Manager - Emergency Preparedness. Pacific Gas and Electric Company acknowledged the findings presented.

The inspectors presented the permanent plant modifications inspection results to Mr. Robert Waltos, Manager - Equipment Reliability, and other members of Pacific Gas and Electric Company management at the conclusion of the inspection on May 15, 2003. Pacific Gas and Electric Company acknowledged the findings presented.

The inspectors asked Pacific Gas and Electric Company whether any materials examined during the inspection should be considered proprietary. Proprietary information was reviewed by the inspectors and left with Pacific Gas and Electric Company at the end of the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

G. Anderson, Assistant Operations Manager
J. Becker, Vice President - Diablo Canyon Operations and Station Director
C. Belmont, Director, Nuclear Quality, Analysis, and Licensing
S. Chesnut, Director, Engineering Services
J. Hays, Director, Maintenance Services
S. Ketelsen, Manager, Regulatory Services
T. King, Training Manager, Learning Services
M. Lemke, Manager, Emergency Preparedness
D. Oatley, Vice President and General Manager, Diablo Canyon
P. Roller, Director, Operations Services
J. Tompkins, Director, Site Services
L. Womack, Vice President Nuclear Services
M. Wright, Manager, Operations

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

50-323/03-06-01	NCV	Failure to Identify and Prevent Check Valve Problems (Section 1R04.4)
50-275/03-06-02	NCV	Failure to Maintain Design Drawings Leads to Inadvertent Inward Rod Motion (Section 1R14.1)
50-323/03-06-03	NCV	Failure to Implement Correct Revision of Procedure Results in Power-Operated Relief Valve Opening (Section 1R14.2)
50-275/03-06-04	NCV	Failure to Promptly Identify and Correct a Faulty Automatic Voltage Regulator Card (Section 4OA2)
50-323/03-06-05	NCV	Failure to implement outage safety management controls to containment closure (Section 4OA3.6)

Closed

50-323/01-004-00	LER	Technical Specification 3.4.10 not met during pressurizer safety valve testing (Section 40A3.1)
50-275; 323/ 01-002-00	LER	Unplanned diesel generator starts due to loss of startup power (Section 4OA3.2)
50-323/02-001-00	LER	Fasteners failed due to stress corrosion cracking (Section 4OA3.3)
50-275/02-003-00, and -01	LER	Unanalyzed condition due to heavy load lifted over a restricted area (Section 4OA3.4)
50-323/03-06-00	LER	Unit 2 auxiliary feedwater system actuation due to personnel error (Section 4OA3.5)
50-323/03-05-02	URI	Failure to implement outage safety management controls to containment closure (Section 4OA3.6)
50-275;323/ 0206-02	URI	Effect of harmonics on second level under-voltage-relay accuracy (Section 4OA5.3)

LIST OF DOCUMENTS REVIEWED

Section 1EP4: Emergency Action Level and Emergency Plan Changes

Procedures

Diablo Canyon Emergency Plan, Revision 4, Changes 1, 2, and 3
EP G-1, "Emergency Classification and Emergency Plan Activation," Revision 32

Section 1R17: Permanent Plant Modifications

Design Change Packages and Notices

Number	Description
DCP J-049434	Replacement of Existing Westinghouse RVLIS and TMS Processors, Displays, and Related Hardware
DCP J-050569	Upgrade of PORV Automatic Actuation Circuitry
DCN 49558	Main Feedwater/Main Steam Flow Scaling
DCN 49525	Install New RVRLIS and PPC MUX in Containment
DCN 49475	RVLIS Train B replacement Project
DCN 49565	Evaluation of HELB Barrier Requirements and Installation
DCN 50522	Centrifugal Charging Pump -1 Head Replacement

Maintenance Modifications

Number	Description
MM AO553069	Add RV to Protect PCV-474 From Overpressure (U-1)
MM AO561542	Weld Design Change
MM AO526773	Add Bypass Switches in E21 for CNTNMT HHI & P-13
MM AO501939	Modify EDG Circuit (U-1)
MM AO556499	Allowance for Use of Two DC Coil Switches in Size 5 Connector
MM AO531251	Intermediate Canopy Seal Weld Repair

-4-Action Requests

AO506007	AO502896	AO553069	AO561542	AO501939
AO505780	AO570149	AO502890	AO526773	AO556499
AO531251				

Calculations

STA-119, Spurious Safety Injection Analysis, Revision 0

STA-154, Operator Action Times Assumed for the Spurious Safety Injection Analysis Performed in Calculation STA-119 Based on the Average Times Recorded During Simulator Validation Scenarios, Revision 0

Procedures

CF3.ID9, "Design Change Package Development," Revision 20A
CF4.ID3, "Design Change Package Implementation," Revision 14
CF3.ID10, "Maintenance Modification Action Requests," Revision 16A
TS3-ID2, "Licensing Basis Impact Evaluations," Revisions 12 through 16

Emergency Operating Procedures

EOP E-1.1, "SI Termination," Revision 19
EOP E-0, "Reactor Trip or Safety Injection," Revision 27

Drawings and Sketches

102007, Sheet 7A, Revision 50
102033, Sheet 13A, Revision 0
102033, Sheet 16D, Revision 105
102036, Sheet 8L, Revision 117
6010342, Sheet 174, Revision 4
6010342, Sheet 179, Revision 3
SK-4024910-1, Revision 0
SK-445294, Revision 0
SK-437940, Revision 0
SK-437914, Revision 0
SK-57679, Revision 0
SK-108036, Revision 72

Section 1R11: Licensed Operator Requalification

Instructor Lesson Guide, Session 02-5, "Load Rejection/ CO2 Discharge"

-5-OCT Steering Committee Meeting Minutes
9/7/2001; 10/10/2001; 11/30/2001; 02/07/2002; 3/15/2002; 4/18/2002; 6/28/2002; 8/1/2002

Management Observation of Training Feedback Sheets from Courses
R022, R023, R01, R01-02, R014, R017

Package #8 Simulator Exams
E3ECA33A.DOC
FRS1A.DOC

Package #8 JPMs
LJC030.DOC
LJC053.DOC
LJP029.DOC
LJP099.DOC
LJP135.DOC

Package #12 Simulator Exams
E2ECA21C.DOC
ECA1112D.DOC

Package #12 JPMs
LJC044.DOC
LJC069.DOC
LJP073.DOC
LJP095.DOC
LJP130.DOC

DCPP Simulator Performance Test ANSI-3.5 Test Procedure 3.1.2(3)(d)-2, Malfunction EPS4C, "4KV Bus Feeder Breaker Trip"

DCPP Simulator Performance Test ANSI-3.5 Test Procedure B.2.2.(1), "Manual Reactor Trip"

DCPP Simulator Performance Test ANSI-3.5 Test Procedure B.2.2.(4), "Trip of All Reactor Coolant Pumps"

DCPP Simulator Performance Test ANSI-3.5 Test Procedure B.2.2.(5), "Trip of Any Single Reactor Coolant Pump"

DCPP Simulator Performance Test ANSI-3.5 Test Procedure Results 3.1.1.(10)(b), "Surveillance Test on Safety Injection Pump"

DCPP Surveillance Test Procedure Number STP P-SIP-11, "Routine Surveillance Test of Safety Injection Pump 1-1," Revision 12.

DCPP Annunciator Response Procedure Number AR PK18-16, "4KV Bus Diff Lockout," Revision 8, dated 9/26/00.

DCPP Annunciator Response Procedure Number AR PK18-17, "4KV Bus F Bus OR SU FDR UV," Revision 7A, dated December 14, 1999.

DCPP Annunciator Response Procedure Number AR PK18-22, "480V Bus 1F," Revision 15, dated February 18, 2003.

DCPP Simulator Annual Transient Performance Test List (2001)

DCPP Administrative Procedure Number CF2.DC1, "Configuration Management Plan for the Operator Training Simulator," Revision 3, dated April 9, 2003

DCPP Software quality Assurance Plan Procedure Number SQA 99-2, "Operator Training Simulator Software Quality assurance Plan," Revision 0"

DCPP Administrative Procedure CF2.DC1, "Simulator Change Request/Follower," SCR-01-57, "SI Pump Discharge Pressure Decays Too Fast"

DCPP Administrative Procedure Number CF2.DC1, "Simulator Change Request/Follower," SCR-03-099, "Malfunction Rod 9A Doesn't Work Correctly"

Simulator/Plant Differences of Note

List Active SCR's Sorted by Type and Status as of May 13, 2003.

Licensed Operators R02-9 Biennial Exams Week of May 13-16, 2003, Scenarios

LIST OF ACRONYMS

AFW	auxiliary feedwater
ASW	auxiliary saltwater
AR	action request
DEG	diesel engine generator
CFR	*Code of Federal Regulations*
FSAR	Final Safety Analysis Report
INPO	Institute for Nuclear Power Operations
LOCA	loss-of-coolant accident
LER	Licensee Event Report
NCR	nonconformance report
NCV	noncited violation
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records System
PORV	power-operated relief valve
SCO	senior control operator
SDP	Significance Determination Process
SI	safety injection
SORV	stuck open relief valve
URI	unresolved item