UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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January 25, 2006

Jack S. Keenan, Senior Vice
President of Generation and
Chief Nuclear Officer
Mail Code B32
Pacific Gas and Electric Company
P.O. Box 770000
San Francisco, CA 94177-0001

Dear Mr. Keenan:

SUBJECT: ERRATA OF NRC INSPECTION REPORT 05000275/2004005 AND 05000323/2004005

This errata corrects the volume of water that was lost from the spent fuel pool on December 23, 2004, from 36,000 gallons to 3600 gallons. Please replace the first page of the Summary of Findings and pages 14-16 of NRC Inspection Report 05000275/2004005 and 05000323/2004005, dated February 11, 2005, with the enclosed revised pages.

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

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

Sincerely,

/RA/

William B. Jones, Chief
Project Branch B
Division of Reactor Projects

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

Enclosure:
Revised pages of NRC Inspection
Report 05000275\2004005 and 05000323\2004005

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SUNSI Review Completed: _wbj__ ADAMS: : Yes ☐ No Initials: __wbj_
: Publicly Available ☐ Non-Publicly Available ☐ Sensitive : Non-Sensitive

R:_REACTORS_DC\2004\DC2004-05RP Errata

RIV:SRI:DRP/B	C:DRP/B			
TWJackson;df	WBJones			
T - WBJ	***/RA/***			
1/25/06	1/25/06			

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SUMMARY OF FINDINGS

IR 05000275/2004-005, 05000323/2004-005; 10/01/04 - 12/31/04; Diablo Canyon Power Plant Units 1 and 2; Operability Evaluations, Event Followup, Personnel Performance Related to Nonroutine Plant Evolutions and Events, Equipment Alignment, Access Control To Radiologically Significant Areas, Other.

This report covered a 13-week period of inspection by resident inspectors and announced inspections in the areas of inservice inspections, emergency preparedness, and radiation protection. Five self-revealing, four NRC-identified Green noncited violations, and one unresolved item with potential safety significance greater than Green were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609 “Significance Determination Process.” Findings for which the Significance Determination Process does not apply may be Green or be assigned a severity level after NRC management 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. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Initiating Events

- <u>Green</u>. A self-revealing noncited violations was identified for the failure to appropriately implement the procedure for spent fuel pool skimmer filter replacement, as required by Technical Specification 5.4.1.a. On December 23, 2004, operators cleared the spent fuel pool skimmer system using Section 6.3.1 of Procedure OP B-7:III, “Spent Fuel Pool System - Shutdown and Clearing and Filter Replacement,” Revision 15, instead of the appropriate section, which was Section 6.3.2. A human performance crosscutting aspect was identified for the failure on two occasions to address configuration control concerns with the system.

  This finding impacted the Initiating Events Cornerstone and was considered more than minor using Example 5.a of IMC 0612. Specifically, Valve SFS-2-3 was mis-positioned due to the use of the wrong section of Procedure OP B-7:III and then returned to service. Additionally, operators had two opportunities to identify the mis-positioning of Valve SFS-2-3 but failed to identify the condition. The mis-positioned valve resulted in a loss of approximately 3600 gallons of water from the spent fuel pool. This finding was reviewed by NRC management in accordance with IMC 0609 and 0612 and determined to be of very low safety significance (Section 1R14.2).

Cornerstone: Mitigating Systems

- <u>Green</u>. A self-revealing, noncited violation was identified for the failure to setup phase sequence test equipment according to procedure, as required by 10 CFR Part 50, Appendix B, Criterion V. This failure resulted in the momentary de-energization of Vital 4kV Bus G and the auto-start of Diesel Engine Generator 2-1. Subsequent investigation by Pacific Gas & Electric Company revealed that the primary side of the test transformer was wired in a wye configuration instead of a delta configuration. This were also evident for the feedwater level controller malfunction. The inspectors determined that with the information provided in the procedure and the plant conditions, that there was sufficient evidence to result in the shift foreman deciding to trip the reactor and close the main steam isolation valves. Furthermore, the inspectors observed that PG&E had not developed a procedural bases for the actions specified by Step 5.1.1. A human performance crosscutting aspect (resources) was identified for the inadequate alarm procedure. The inspectors are reviewing the adequacy of alarm response Procedure AR PK 10-21 to address a feedwater heater level control malfunction as an unresolved item.

Analysis. No analysis was performed for this unresolved item.

Enforcement. Unresolved Item (URI) 50-323/04-05-03, Adequately of Alarm Procedure For Feedwater Heater Level Control Malfunctions.

.2 Unit 2 Spent Fuel Pool (SPF) Level Drop

a. Inspection Scope

On December 23, 2004, the Unit 2 SPF level dropped approximately 4 inches as a result of Valve SFS-2-3, SFP skimmer pump casing drain to miscellaneous equipment drain tank, being left open following a filter replacement. The inspectors observed operator actions and equipment performance following the event. The inspectors also interviewed operations personnel and reviewed the event for corrective actions, violation of requirements, and generic issues.

b. Findings

Introduction. A Green, self-revealing NCV was identified for the failure to appropriately implement the procedure for SFP skimmer filter replacement, as required by Technical Specification 5.4.1.a. This failure resulted in a loss of approximately 3600 gallons of water from the SFP.

Description. On December 23, 2004, operators implemented Clearance 79718 for replacing the SFP skimmer filter. Attached to the clearance was Procedure OP B-7:III, “Spent Fuel Pool System - Shutdown and Clearing and Filter Replacement,” Revision 15. Section 6.3.1 of the procedures for shutting down and clearing the skimmer pump and strainer had been marked for implementation. Following the implementation of the clearance, the work control lead observed that Section 6.3.1 of Procedure OP B-7:III was used, when Section 6.3.2, steps ‘a’ through ‘e’, should have been used. Section 6.3.2 of the procedure specifically addressed replacement of the SFP skimmer filter. The work control lead marked steps ‘g’ through ‘l’ of Section 6.3.2

for returning the SFP skimmer pump back to service. He noticed that, because Section 6.3.1 had been used to clear the pump, 4 valves would be potentially mis-positioned. The work control lead discussed the potential for the 4 valves to be potentially mis-positioned with the oncoming shift work control lead.

Following SFP skimmer filter replacement, the oncoming shift work control lead informed operators to restore the SFP skimmer system using Section 6.3.2. The work control lead also informed the operators that he was not sure how the SFP skimmer system had been cleared by the previous shift. Operators restored the SFP skimmer system, and when they started the system, they found 3 valves mis-positioned. Approximately 3 hours later operators noticed a steady increasing level in the miscellaneous equipment drain tank. Operators then found that Valve SFS-2-3 was still mis-positioned from the clearance of the skimmer pump. For the 3 hours that Valve SFS-2-3 was mis-positioned, approximately 3600 gallons of water was drained from the SFP.

The inspectors determined that PG&E failed to properly implement Procedure OP B-7:III when clearing the SFP skimmer system. Section 6.3.2 specifically addressed replacement of the SFP skimmer filter. The inspectors also observed that other operators were aware of a potential mis-position of valves. However, the need for checking the alignment of these valves had not been adequately communicated to and/or carried out by the operators who restored the SFP skimmer system. The operators who restored the SFP skimmer system recognized and corrected the 3 mis-positioned valves, but failed to adequately investigate the reason for the mis-position, which was a missed opportunity to discover the 4th mis-positioned valve. A human performance cross cutting aspect was identified for the failure on two occasions to address configuration control concerns with the system.

<u>Analysis</u>. The performance deficiency associated with this event is the failure to properly implement Procedure OP B-7:III as required by Technical Specification 5.4.1.a. This deficiency impacted the Initiating Events Cornerstone that limit the likelihood of events that upset plant stability during shutdown and affected the configuration control attribute for operating equipment lineup. The finding was considered more than minor using Example 5.a of Inspection Manual Chapter 0612. Specifically, Valve SFS-2-3 was mis-positioned due to the use of the wrong section of Procedure OP B-7:III and then returned to service. Additionally, operators had two opportunities to identify the mis-positioning of Valve SFS-2-3 but failed to identify the condition. The mis-positioned valve resulted in a loss of approximately 3600 gallons of water from the spent fuel pool. This finding was reviewed by NRC management in accordance with Inspection Manual Chapter 0609 and 0612 and determined to be of very low safety significance. This determination was based on the performance deficiency would not have resulted in a loss of spent fuel pool inventory below the Technical Specification required level on a loss of spent fuel pool cooling.

Enforcement. Technical Specification 5.4.1.a requires, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2. Item 3.h of Regulatory Guide 1.33, Appendix A recommends procedures for startup, operation, and shutdown of fuel storage pool purification and cooling systems. Contrary to the above, PG&E failed to properly implement Procedure OP B-7:III with regards to replacing the SFP skimmer filter. The failure to properly implement this procedure resulted in mis-position of Valve SFS-2-3 and the loss of approximately 3600 gallons of water from the SFP. Because the failure to properly implement Procedure OP B-7:III is of very low safety significance and has been entered into the corrective action system as AR A0628635, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/04-05-04, Failure to Properly Implement Procedure for Spent Fuel Pool Skimmer Filter Replacement.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed seven inspection samples of operability evaluations. These reviews of operability evaluations and/or prompt operability assessments and supporting documents were performed to determine if the associated systems could meet their intended safety functions despite the degraded status. The inspectors reviewed the applicable Technical Specification, Codes/Standards, and Final Safety Analysis Report Update sections in support of this inspection. The inspectors reviewed the following AR's and operability evaluations:

- (Unit 2) Environmental qualification of auxiliary feedwater flow indication cable (ARs A0620857, A0621502)
- (Unit 1) Emergency core cooling system (ECCS) voiding (AR A0621502)
- (Unit 1) Startup Transformer 1-1 automatic tap changer in manual due to unexpected step increases (AR A0625650)
- (Unit 2) Residual Heat Removal Pump 2-2 socket weld crack at suction pressure instrument line (AR A0624790)
- (Units 1 and 2) Valve FW-2-LCV-110 failed closed (AR A0624790)
- (Unit 2) DEG 2-3 lube oil instrument line crack (AR A0617419)
- (Unit 1) Small water drip on feedwater pipe lead 2-2 (AR A0628484)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
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611 RYAN PLAZA DRIVE, SUITE 400
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February 11, 2005

EA 04-169

Gregory M. Rueger, Senior Vice
President, Generation and Chief Nuclear Officer
Pacific Gas and Electric Company
Diablo Canyon Power Plant
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SUBJECT: DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000275/2004005 AND 05000323/2004005

Dear Mr. Rueger:

On December 31, 2004, 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 January 6, 2005, with Mr. David H. Oatley and other 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.

This report documents one unresolved item concerning the potential unavailably of an emergency diesel generator in Unit 2 due to a cracked lube oil sensing line. This finding has potential safety significance greater than very low safety significance. The line was isolated on September 28, 2004, to mitigate any safety concerns and the diesel engine was declared operable.

There were four NRC-identified findings and five self-revealing findings of very low safety significance (Green) identified in this report. These findings involved violations of NRC requirements. However, because of their very low risk significance and because they are entered into your corrective action program, the NRC is treating these ten 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.

In accordance with 10 CFR 2.390 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
Project Branch E
Division of Reactor Projects

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

Enclosure:
Inspection Report 05000275/2004005
and 05000323/2004005
w/attachment: Supplemental Information

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SISP Review Completed: _WBJ__ ADAMS: / Yes ☐ No Initials: _WBJ__
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R:_DC\2004\DC2004-05RP-DLP.wpd

RIV:SRI:DRP/E	SRI:DPE/E	C:DRS/EB	C:DRS/PEB	C:DRS/PSB
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2/11/05	2/4/05	2/10/05	2/11/05	2/10/05

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2/11/05	2/11/05			

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-275, 50-323
Licenses:	DPR-80, DPR-82
Report:	05000275/2004005 05000323/2004005
Licensee:	Pacific Gas and Electric Company (PG&E)
Facility:	Diablo Canyon Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	October 1 through December 31, 2004
Inspectors:	D. L. Proulx, Senior Resident Inspector T. W. Jackson, Resident Inspector V. G. Gaddy, Senior Project Engineer R. Lantz, Senior Emergency Preparedness Inspector G. Johnston, Senior Reactor Engineer D. L. Stearns, Project Engineer W. C. Sifre, Reactor Inspector G. D. Replogle, Senior Reactor Inspector J. I. Tapia, Senior Reactor Inspector B. D. Baca, Health Physicist
Approved By:	W. B. Jones, Chief, Projects Branch E Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000275/2004-005, 05000323/2004-005; 10/01/04 - 12/31/04; Diablo Canyon Power Plant Units 1 and 2; Operability Evaluations, Event Followup, Personnel Performance Related to Nonroutine Plant Evolutions and Events, Equipment Alignment, Access Control To Radiologically Significant Areas, Other.

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A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing noncited violations was identified for the failure to appropriately implement the procedure for spent fuel pool skimmer filter replacement, as required by Technical Specification 5.4.1.a. On December 23, 2004, operators cleared the spent fuel pool skimmer system using Section 6.3.1 of Procedure OP B-7:III, "Spent Fuel Pool System - Shutdown and Clearing and Filter Replacement," Revision 15, instead of the appropriate section, which was Section 6.3.2. A human performance crosscutting aspect was identified for the failure on two occasions to address configuration control concerns with the system.

  This finding impacted the Initiating Events Cornerstone and was considered more than minor using Example 5.a of IMC 0612. Specifically, Valve SFS-2-3 was mis-positioned due to the use of the wrong section of Procedure OP B-7:III and then returned to service. Additionally, operators had two opportunities to identify the mis-positioning of Valve SFS-2-3 but failed to identify the condition. The mis-positioned valve resulted in a loss of approximately 36,000 gallons of water from the spent fuel pool. This finding was reviewed by NRC management in accordance with IMC 0609 and 0612 and determined to be of very low safety significance (Section 1R14.2).

Cornerstone: Mitigating Systems

- Green. A self-revealing, noncited violation was identified for the failure to setup phase sequence test equipment according to procedure, as required by 10 CFR Part 50, Appendix B, Criterion V. This failure resulted in the momentary de-energization of Vital 4kV Bus G and the auto-start of Diesel Engine Generator 2-1. Subsequent investigation by Pacific Gas & Electric Company revealed that the primary side of the test transformer was wired in a wye configuration instead of a delta configuration. This wiring configuration introduced a direct short to ground, which caused the second level undervoltage relay to sense a degraded bus voltage for Vital 4kV Bus G. Subsequently, the relay removed the auxiliary power supply from Bus G and caused DEG 2-1 to start and load onto the bus. This finding involved a human performance crosscutting aspect for the failure to wire the phase sequence test equipment properly for Vital 4kV Bus G and DEG 2-1.

The finding impacted the Mitigating Systems Cornerstone for ensuring the availability and capability of systems that respond to initiating events to prevent undesirable consequences that was associated with a pre-event human error performance. Considering Example 4.b of Inspection Manual Chapter 0612, Appendix E, the finding is greater than minor since the incorrect wiring and connection of the test equipment resulted in a vital bus de-energization and the actuation of DEG 2-1. Using Checklist 4 of Inspection Manual Chapter 0609, Appendix G, Attachment 1, the finding did not result in the Technical Specifications for AC and DC power sources not being met and the finding was determined not to increase the likelihood of a loss of reactor coolant system inventory, degrade Pacific Gas & Electric Company's ability to terminate a leak path or add reactor coolant system inventory when needed, or degrade Pacific Gas & Electric Company's ability to recover decay heat removal once it is lost. Therefore, the finding was screened as having very low safety significance (Section 4OA3.1).

- Green. The inspectors identified an noncited violation of 10 CFR 50 Appendix B, Criterion XVI, for the failure to take adequate corrective actions to prevent a void space in the Unit 1 emergency core cooling system piping from exceeding the volume allowed by plant procedures. The void space volume caused operators to declare the emergency core cooling system inoperable and enter Technical Specification 3.0.3 twice on October 21, 2004. Operation of the positive displacement pump, with subsequent operation of the centrifugal charging pump, had been discovered to create a void in the emergency core cooling system piping approximately five months earlier on Unit 2. This finding had problem identification and resolution crosscutting aspects for determining the extent of the condition and preventing its recurrence.

  The finding affected the Mitigating System cornerstone for ensuring the capability of systems that respond to initiating events to prevent undesirable consequences and it affected the equipment performance attribute for availability and reliability. The finding is greater than minor because it is similar to Example 2.f in Appendix E of Inspection Manual Chapter 0612. Similar to the example, the void size had exceeded the limit described in Calculation STA-108, "Allowable Accumulated Gas Volume in the CCPs' [centripetal charging pump] and SIPs' [safety injection pump] Suction Cross-Tie Piping," Revision 3. Using the Inspection Manual Chapter 0609 Phase 1 Screening Worksheet, the finding was of very low safety significance (Green) since the finding is not a design or qualification deficiency that was confirmed to result in a loss of function per Generic Letter 91-18 (Section 1R15).

- TBD. An unresolved item was identified for the failure to promptly correct a cracked lube oil instrument sensing line, as required by 10 CFR Part 50, Appendix B, Criterion XVI. On August 29, 2004, operators observed a lube oil leak from the weld connecting the outlet of Valve DEG-2-1084 to instrument tubing. Approximately one month later, the leak had increased and it was discovered that the circumferential crack was 180 degrees through-wall on the weld. As a result, there was an increased potential for DEG 2-3 to trip on low lube oil level. This finding had problem identification and resolution crosscutting aspects associated with operations and engineering personnel not recognizing the significance of the degraded condition and not implementing timely corrective actions.

  This finding is unresolved pending a review of the crack propagation, the potential impact on the diesel engine and completion of a significance determination. This finding impacted the Mitigating Systems Cornerstone for reliability of systems that respond to initiating events to prevent undesirable consequences and affects the equipment performance attribute. The finding was more than minor using Example 4.f of Inspection Manual Chapter 0612, Appendix E. Similar to Example 4.f, the inspectors determined that there was impact to DEG 2-3 operability. Using the SDP Phase 1 screening worksheets in Appendix A of Inspection Manual Chapter 0609, the finding was determined to have potentially greater than very low safety significance because the failure could have resulted in an actual loss of the diesel engine Generator 2-3 during a loss of offsite power event (Section 1R15).

- Green. A self-revealing violation of 10 CFR 50.49(f) was identified for the failure to maintain approximately 70 safety related solenoid operated valves in an environmentally qualified condition. On February 9, 2002, an age related ASCO solenoid operated valve failure caused a loss of steam generator feedwater event and a Unit 2 manual plant trip. Further, the licensee did not promptly evaluate the extent of condition of the ASCO failure (coil insulation failure), which delayed the identification of elastomer qualification issues for approximately 1 year. In a related finding, the team identified that the licensee had missed earlier opportunities to identify ASCO elastomer qualification issues, in that they failed to thoroughly evaluate several pertinent NRC information notices and previous valve failures. The failure to: 1) properly establish equipment qualification limits; 2) thoroughly evaluate plant events and failures; and 3) properly evaluate industry operating experience constituted performance concerns. Pacific Gas & Electric Company entered this issue into their corrective action program as Action Request 0613008. These issues have crosscutting aspects in the area of problem identification and resolution because the original problem investigation did not identify the full scope of the cause and extent of condition, delaying some important corrective actions for approximately 1 year.

  This finding was greater than minor because, if left uncorrected, these deficiencies would become a more significant safety concern by increasing the failure rate as the components age. An NRC Senior Reactor Analyst performed a Phase 3 significance determination and the estimated delta-CDF for the finding is 2.2E-8/yr. This violation was of very low risk significance (Section 4OA5).

Cornerstone: Barrier Integrity

- Green. The inspectors identified a noncited violation for the failure to develop a core offload sequence that maintained the source range neutron flux monitors operable, as required by 10 CFR Part 50, Appendix B, Criterion V. Inaccurate labeling of two neutron detectors in the core offload planning tool resulted in the development of a core offload sequence that when implemented resulted in one of the detectors becoming neutronically uncoupled from the core during core alterations. A human performance crosscutting aspect was identified for the labeling error in the core offload planning. A second human performance crosscutting aspect was identified for the failure to ascertain the cause of the downward trend when first identified by the inspectors.

  The finding impacts the Barrier Integrity Cornerstone to provide reasonable assurance that physical design barriers protect the public from radio nuclide releases caused by accidents or events and is associated with the barrier performance attribute for procedure quality which could impact cladding. The finding is more than minor when compared to Example 4.e of Inspection Manual Chapter 0612, Appendix E. Similar to the example, Procedure OP B-8DS1, Step 5.2.1, described a responding nuclear instrument as having at least one fuel assembly face-adjacent or diagonally adjacent to the detector. Due to a labeling error in the core offload planning tool, the core offload sequence was developed in a manner that caused a neutron detector (Detector N-52) not to have an adjacent fuel assembly. Using Checklist 4 of Inspection Manual Chapter 0609, Appendix G, Attachment 1, the finding was determined not to increase the likelihood of a loss of reactor coolant system inventory, degrade Pacific Gas & Electric Company's ability to terminate a leak path or add reactor coolant system inventory when needed, or degrade Pacific Gas & Electric Company's ability to recover decay heat removal once it is lost. Therefore, the finding was screened as having very low safety significance (Section 1R04.1).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, for the failure to promptly correct reverse rotation of containment fan cooler units for both Units 1 and 2. Pacific Gas & Electric Company observed reverse rotation of containment fan cooler units for approximately 13 years, as a result of the containment fan cooler units backdraft dampers sticking partially open. The purpose of the backdraft dampers is to prevent reverse rotation of the containment fan cooler units, which could cause the fan motor to trip on overcurrent when the containment fan cooler units are started following a loss of coolant accident. Prior to Refueling Outage 2R12, 2 containment fan cooler units in Unit 1 and 3 containment fan cooler units in Unit 2 exhibited reverse rotation. One of the containment fan cooler units in Unit 2 was considered inoperable due to reverse rotation and another was only considered operable if it was running. A problem identification and resolution crosscutting aspect was identified for the failure to correct the reverse rotation of the containment cooler fans.

The finding impacts the Barrier Integrity Cornerstone to provide reasonable assurance that physical design barriers protect the public from radio nuclide releases caused by accidents or events and is associated with the barrier performance attribute. The finding is more than minor when considering Example 3.g of Inspection Manual Chapter 0612, Appendix E. Similar to the example, Pacific Gas & Electric Company observed reverse rotation of containment fan cooler units for 13 years, and the reverse rotation impacted the operability of the containment fan cooler units. Using the SDP Phase 1 Screening Worksheet from Inspection Manual Chapter 0609, the finding was determined to be of very low safety significance since it was determined that there was not an actual loss of defense-in-depth in containment pressure control or hydrogen control (Section 1R04.2).

Cornerstone: Emergency Preparedness

C Green. The inspectors identified a violation of 10 CFR 50.54(q) and 50.47.b(4) for the failure to maintain the seismic force monitors during the periods, June 16-19,1999, December 1-4, 2000, April 25-27, 2002, May 25-29, 2002, November 6-8, 2003, December 30-31, 2003, and August 9-10, 2004, such that the emergency plan designed to meet planning standard (4) in 10 CFR 50.47(b) could be promptly implemented. Specifically, Pacific Gas & Electric Company failed to provide a means for the emergency director to promptly classify seismic events at the notification of unusual event, alert or site area emergency levels, while the seismic force monitor utilized by the operators (emergency director) was out of service or being replaced. This finding had a human performance cross-cutting aspect associated with identifying compensatory measures to address the removal of the earthquake force monitors.

This performance deficiency impacted the emergency preparedness cornerstone because Pacific Gas & Electric Company's did not meet an emergency planning requirement and the cause was reasonably within Pacific Gas & Electric Company's control and should have been prevented. It is greater than minor because it has a potential to impact safety and because it was not a record keeping or administrative issue or an insignificant procedural error. This deficiency could have affected the emergency preparedness cornerstone objective of ensuring the capability to implement measures to protect the health and safety of the public during an emergency, and is associated with attributes of facilities and equipment, and offsite emergency preparedness. The finding is evaluated using the Emergency Preparedness "Failure to Comply" flowchart of the SDP and is a violation of 10 CFR 50.54(q) and planning standard 50.47(b)(4), which states, in part, that a standard emergency action level and classification system... is in use Utilizing the Failure to Comply Flow Chart in Manual

Chapter 0609, the performance deficiency does not result in a failure of the risk significant planning standard or a degraded risk significant planning standard in that the unavailability of the seismic monitors would not prevent the declaration of a Site Area Emergency, Alert or Notification of Unusual Event (Section 4OA5).

Cornerstone: Occupational Radiation Safety

- Green. A self-revealing noncited violation of Technical Specification 5.7.2 was reviewed as a result of Pacific Gas & Electric Company's failure to prevent unauthorized entry of a portion of the whole body into a high radiation area with dose rates greater than 1 rem per hour. Specifically, on November 14, 2004, Pacific Gas & Electric Company failed to use an effective locking mechanism on the lower access flaps of the primary steam generator shield doors. The ineffective locking mechanism was discovered two days later when workers went to remove suction hoses. This could have allowed an individual to expose the arm above the elbow to dose rates greater than 1 rem per hour. This finding was placed into Pacific Gas & Electric Company's corrective action program.

  The finding is greater than minor because it is associated with one of the cornerstone attributes (exposure control) and affected the cornerstone objective because it could have resulted in unplanned, unintended radiation dose. The inspector determined that the finding was of very low significance because (1) it was not an ALARA finding, (2) it was not an overexposure, (3) it did have a substantial potential for overexposure, and (4) it did not compromise the ability to assess doses. This finding also had crosscutting aspects associated with human performance (Section 2OS1).

- Green. A self-revealing noncited violation of Technical Specification 5.7.2 was reviewed as a result of Pacific Gas & Electric Company's failure to prevent two individuals from entering a high radiation area with dose rates greater than 1 rem per hour on the incorrect radiation work permit. Two individuals entered an area with dose rates of 6 rem per hour in Reactor Coolant Pump Cubicle 2-4 using a radiation work permit which only allowed entry into areas with dose rates up to 1 rem per hour. This finding was placed into Pacific Gas & Electric Company's corrective action program.

  The finding is greater than minor because it is associated with one of the cornerstone attributes (exposure control) and affected the cornerstone objective because it could have resulted in unplanned, unintended radiation dose. The inspector determined that the finding was of very low significance because (1) it was not an ALARA finding, (2) it was not an overexposure, (3) it did have a substantial potential for overexposure, and (4) it did not compromise the ability to assess doses. This finding also had crosscutting aspects associated with human performance (Section 2OS1).

B. Licensee-Identified Violations

Violations of very low significance were identified by Pacific Gas & Electric Company and have been reviewed by the inspectors. Corrective actions taken or planned by Pacific Gas & Electric Company appear reasonable. The violations are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Diablo Canyon Unit 1 began this inspection period at 100 percent power. On December 20, 2004, operators reduced reactor power to approximately 84 percent power for main turbine valve testing and Path 15 transmission line testing. Operators restored reactor power to 100 percent on December 21, 2004, following completion of testing. Unit 1 remained at 100 percent power for the duration of the inspection period.

Diablo Canyon Unit 2 began this inspection period at 100 percent power. On October 3, 2004, operators reduced Unit 2 reactor power to approximately 50 percent to support main condenser cleaning. Following cleaning activities, reactor power was returned to 100 percent.

On October 25, 2004, operators commenced a Unit 2 reactor shutdown for Refueling Outage 2R12 and entered Mode 3 (Hot Standby). Operators initiated a plant cooldown and entered Mode 4 (Hot Shutdown) on October 25 and Mode 5 (Cold Shutdown) on October 26. On October 30 Unit 2 entered Mode 6 (Refueling) when maintenance personnel de-tensioned the reactor vessel head. Operators commenced core offload on November 2 and completed core offload on November 4. Unit 2 remained de-fueled until November 22 when Unit 2 entered Mode 6 as a result of operators reloading fuel into the reactor vessel. Unit 2 entered Mode 5 on November 28 when maintenance personnel tensioned the reactor vessel head. Operators began increasing reactor coolant temperature, and Unit 1 entered Mode 4 on December 5. Operators continued to increase reactor coolant temperature, and Unit 2 entered Mode 3 on December 8. On December 10 operators commenced a reactor startup, and Unit 2 reached Mode 2 (Startup). Operators continued to increase reactor power, and Unit 2 entered Mode 1 (Power Operations) on December 12. On December 16 the Unit 2 main generator was paralleled to the grid; ending Refueling Outage 2R12. Unit 2 reached 100 percent power on December 22 and remained at that power level for the duration of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather (71111.01)

a. Inspection Scope

Cold Weather Operations

The inspectors reviewed the Primary and Backup Meteorological temperature readings for the inspection period to determine if adequate protections against cold weather were necessary to prevent freezing of outside equipment. The inspectors noted that the minimum outside temperature for the inspection period was 45°F, which was expected for coastal weather conditions. The cold weather or freeze protection was therefore not necessary, and a complete inspection sample could not be performed.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

The inspectors performed two partial system walkdowns during this inspection period.

Partial System Walkdowns

.1 Unit 2 Gammametrics Neutron Detector N-52

a. Inspection Scope

On November 3, 2004, while Source Range Detector N-32 was in a maintenance outage window, the inspectors performed a partial system walkdown of the Gammametrics Neutron Detector N-52. The inspectors observed alignment, the availability of electrical power, and procedural usage of the equipment. The inspectors used the following documents:

- Drawing 108007, “Neutron Detector & Temperature Monitor Locations,” Sheet 6, Revision 38
- Procedure PEP R-8DS1, “Core Offload Sequence,” Revision 6
- Procedure OP B-8DS1, “Core Unloading,” Revision 34

b. Findings

Introduction. The inspectors identified a Green noncited violation (NCV) for the failure to develop a core offload sequence that maintained the operability of the source range neutron flux monitors, as required by 10 CFR Part 50, Appendix B, Criterion V. Inaccurate labeling of the neutron detector for core offload planning maps resulted in reliance on one of two detectors that had became neutronically uncoupled from the core during core offload and required suspension of core alterations.

Description. Technical Specification 3.9.3 requires two source range neutron flux monitors be operable while in Mode 6. The purpose of the detectors is to alert operators to unexpected changes in core reactivity, such as a boron dilution accident or an improperly loaded fuel assembly. Prior to core offload, Source Range Detector N-32 was removed from service for maintenance. The Diablo Canyon licensing basis provides the use of either the Gammametrics Neutron Detectors, N-51 or N-52, as alternate source range neutron flux monitors. Pacific Gas & Electric Company (PG&E) chose to use Detector N-52 and Source Range Detector N-31 as the two operable source range neutron flux monitors during core offload. Reactor engineers planned to remove the fuel assemblies farthest from the two detectors first, so that the detectors would always sense the reactivity of the fuel assemblies. Core offloading was controlled by Procedure OP B-8DS1, which referenced Procedure PEP R-8DS1. Procedure PEP R-8DS1 controlled the core offload sequence.

On November 3, 2004, operators were in the process of removing fuel assemblies from the Unit 2 reactor vessel. When operators had offloaded 46 fuel assemblies, reactor engineers recommended that operators not remove any more fuel assemblies until it was understood why the source range reading from Detector N-52 had trended down. Subsequently, reactor engineers discovered that the core offload sequence was developed using both a paper and computer-based map that had incorrectly labeled Detector N-51 as N-52. Reactor engineers determined that Gammametrics Neutron Detector N-52 had become neutronically decoupled from the core (i.e., would not be able to adequately sense reactivity changes due to the distance to the fuel assemblies). Operators then declared Detector N-52 inoperable. Operators also suspended core alterations, as required by Technical Specification 3.9.3, Refueling Operations, until it was later verified that Detector N-51 could now be used as the second source range neutron flux monitor.

The inspectors verified operator actions prior to, and following, the suspension of core alterations. On November 3, 2004, prior to the suspension of core alterations, the inspectors questioned operators concerning the downward trend of Detector N-52. At that time, operators stated that the trend was expected. The inspectors noted that the operators, with reactor engineering concurrence, continued with the core offload until they later questioned the declining trend. A human performance crosscutting aspect was identified for the labeling error in the core offload planning maps, which subsequently resulted in the core offload sequence being developed in a manner that caused Detector N-52 not to have any adjacent fuel assembly. A second human performance crosscutting aspect was identified for the failure to ascertain the cause of the downward trend when first identified by the inspectors.

Analysis. The performance deficiency associated with this finding is the failure to develop an adequate core offload sequence that would have maintained the operability of both source range neutron flux monitors. The finding impacts the Barrier Integrity Cornerstone to provide reasonable assurance that physical design barriers protect the public from radio nuclide releases caused by accidents or events and is associated with the barrier performance attribute for procedure quality which could impact cladding. The finding is more than minor when compared to Example 4.e of Inspection Manual Chapter 0612, Appendix E. Similar to the example, Procedure OP B-8DS1, Step 5.2.1 described a responding nuclear instrument as having at least one fuel assembly face-adjacent or diagonally adjacent to the detector. Using Checklist 4 of Inspection Manual Chapter 0609, Appendix G, Attachment 1, the finding was determined not to increase the likelihood of a loss of reactor coolant system inventory, degrade PG&E's ability to terminate a leak path or add reactor coolant system inventory when needed, or degrade PG&E's ability to recover decay heat removal once it is lost. Therefore, the finding was screened as having very low safety significance.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, PG&E failed to offload the Unit 2 core in a manner that would have left a fuel assembly adjacent to Detector N-52, in accordance with Procedure OP B-8DS1. The failure to offload the core in the appropriate manner resulted in the inoperability of Detector N-52. Because the failure to offload the core in the appropriate manner is of very low safety significance and has been entered into the corrective action system as AR A0622599, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/04-05-01, Mislabel of Neutron Flux Detector Resulted in Neutronic Decoupling of a Detector From the Core.

.2 Units 1 and 2 Containment Fan Cooler Units (CFCUs)

a. Inspection Scope

On November 26, 2004, while Unit 2 was in a refueling outage, the inspectors performed a partial system walkdown of Units 1 and 2 CFCUs. The inspectors observed valve alignment, the availability of electrical power and cooling water, labeling, lubrication, structural support, and material condition. In addition, the inspectors reviewed corrective action documents pertaining to CFCUs. These documents are listed in Attachment 1.

b. Findings

Introduction. The inspectors identified a Green NCV for the failure to promptly correct CFCU reverse rotation, as required by 10 CFR Part 50, Criterion XVI. The failure to promptly correct CFCU reverse rotation impacted the operability of the CFCUs over the 13-year period that reverse rotation was observed.

Background. The safety-related function of the CFCUs, along with the containment spray system, is to provide containment atmosphere cooling to limit postaccident pressure and temperature inside containment to less than the design values. Technical Specification 3.6.6, Containment Spray and Cooling Systems, requires that at least 3 CFCUs be operable or enter the respective action statements found in Technical Specification 3.6.6. Both Units 1 and 2 have 5 CFCUs each. Each CFCU has a backdraft damper to prevent reverse rotation of the fan, particularly at the onset of a loss-of-coolant accident where the pressure pulse from the break could induce sufficient reverse rotation of the fan. Reverse rotation of the fan could impose high starting currents and cause the CFCUs to trip on overcurrent or overload.

Description. On September 24, 2004, PG&E initiated AR A0619185 to document the adverse trend with respect to CFCU performance. At that time on Unit 2, CFCU 2-5 was inoperable due to reverse rotation, CFCU 2-3 was only considered operable when it was running, and CFCU 2-4 was considered inoperable until its backdraft dampers were verified to be closed. For Unit 1, CFCU 1-1 and CFCU 1-2 exhibited reverse rotation, but were considered operable due to the slow rate of rotation (34 and 30 rpm respectively). The inspectors reviewed the history of CFCU reverse rotation and found that the issue had existed since 1991, as first documented in AR A0224682. The inspectors observed more than 20 ARs from that time to the present that described reverse rotation of CFCUs. The majority of the CFCUs found in reverse rotation were determined to be operable based upon Calculation PET-92-119, "RCFC Reverse Speed vs. Torque," Rev. 0. The inspectors observed that the speed of reverse rotation was dependent upon the size of the opening in the backdraft dampers and the proximity of other running CFCUs. From interviews with maintenance and engineering personnel, and through a review of ARs, the inspectors learned that the backdraft dampers would hang partially open due to damper blades rubbing against the backdraft damper frame, or as a result of broken bolts on some of the blades that would allow them to remain open. Both the blade rubbing and the broken bolts were attributed to the vibration that backdraft dampers are subjected to during normal plant operation. The inspectors also observed that most of the operability determinations for the CFCU reverse rotation were based on the observed reverse rotation speed of the CFCUs and not the potential reverse rotation speed that could be experienced during a design basis accident.

Through a review of ARs, the inspectors identified that two ARs documented an adverse trend in CFCU reverse rotation, while two other ARs evaluated design changes to correct the problem. In September 1996, AR A0421679 was initiated to discuss replacement alternatives to the CFCU backdraft dampers. In this evaluation, PG&E decided to operate and maintain the backdraft dampers as they were. The decision was reached after considering budget issues and the feasibility of design alternatives. In May 2002, AR A0557943 was initiated to again review design alternatives to the CFCU backdraft dampers. Approximately1 year later, PG&E decided to install anti-rotation devices on all the CFCUs. PG&E planned to have the anti-rotation devices installed in Refueling Outages 1R13 and 2R13, which would be Fall 2005 and Spring 2006 respectively. In November 2003, AR A0595426 was written to address a potentially adverse trend with ventilation backdraft dampers. The AR acknowledged one CFCU backdraft damper issue, which was associated with the reverse rotation of CFCU 2-5. The AR was subsequently closed when it was determined that there was not an adverse trend with backdraft dampers. In September 2004, AR A0619185 was written to address the reverse rotation of 5 CFCUs between Units 1 and 2.

The inspectors determined that PG&E had not promptly corrected a condition adverse to quality. CFCU reverse rotation had been observed for approximately 13 years and at least two evaluations had considered corrective actions for the CFCU backdraft dampers. While PG&E has planned corrective actions for the backdraft dampers in AR A0557943, the corrective actions will not come to completion until 3 to 4 years after the AR's initiation. Since the initiation of AR A0557943, the operability of at least two CFCUs has been impacted. The inspectors interviewed maintenance and engineering personnel concerning current actions in Refueling Outage 2R12 to address reverse rotation of CFCUs. The inspectors determined that the preventive maintenance performed on the CFCUs during Refueling Outage 2R12 had no significant difference from maintenance that had taken place in previous refueling outages.

Analysis. The performance deficiency associated with this finding is the failure to promptly correct the reverse rotation of CFCUs. The finding impacts the Barrier Integrity Cornerstone to provide reasonable assurance that physical design barriers protect the public from radio nuclide releases caused by accidents or events and is associated with the barrier performance attribute. The finding is more than minor when considering Example 3.g of Inspection Manual Chapter 0612, Appendix E. Similar to the example, PG&E observed reverse rotation of CFCUs for 13 years, and the reverse rotation impacted the operability of the CFCUs. Using the Significance Determination Process (SDP) Phase 1 Screening Worksheet from Inspection Manual Chapter 0609, the finding was determined to be of very low safety significance since it was determined that there was not an actual loss of defense-in-depth in containment pressure control or hydrogen control.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions,” 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 nonconformance are promptly identified and corrected. Contrary to the above, PG&E failed to promptly correct the reverse rotation of CFCUs, which impacted the operability of the CFCUs for a time span of approximately 13 years. Because this failure to promptly correct the CFCU reverse rotation is of very low safety significance and has been entered into the corrective action program as AR A0619185, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275; 323/04-05-02, Failure to Promptly Correct Containment Fan Cooler Unit Reverse Rotation.

1R06 Flood Protection Measures (71111.06)

.1 Internal Flood Protection

a. Inspection Scope

The inspectors reviewed PG&E’s flood protection measures for Unit 2 to ensure that adequate precautions had been taken to mitigate internal flood risks. In particular, the inspectors reviewed underground electrical conduit inspections performed on the vital 4kV buses during Refueling Outage 2R12. In support of the inspection, system engineers were interviewed and ARs A0615559 and A0620471 were reviewed.

b. Findings

No findings of significance were identified.

.2 External Flood Protection

a. Inspection Scope

The inspectors reviewed PG&E’s flood protection measures for Units 1 and 2 to ensure that adequate precautions had been taken to mitigate external flood risks. In particular, the inspectors walked down the transformer yards for Units 1 and 2 for flooding potential. The inspectors used Chapter 3 of the Final Safety Analysis Report Update and ARs A0621185 and A0621626 in support of this inspection.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

.1 Performance of Nondestructive Examination Activities Other than Steam Generator Tube Inspections

a. Inspection Scope

The inspectors observed the ultrasonic system calibration, and ultrasonic and visual examinations. The inspectors observed five examinations, which are listed in the attachment.

During the review of these examinations, the inspectors verified that the correct nondestructive examination procedure was used, examinations and conditions were as specified in the procedures, and test instrumentation or equipment was properly calibrated and within the allowable calibration period. The inspectors also reviewed the documentation to determine if indications revealed were compared against the American Society of Mechanical Engineers (ASME) Code specified acceptance standards, and that the indications were appropriately dispositioned. The nondestructive examination certifications of the personnel observed performing examinations or identified during review of completed examination packages were reviewed by the inspectors.

b. Findings

No findings of significance were identified.

.2 Steam Generator Tube Inspection Activities

a. Inspection Scope

The inspection procedure specified, with respect to in-situ pressure testing, performance of an assessment of in-situ screening criteria to assure consistency between assumed nondestructive examination flaw sizing accuracy and data from the Electric Power

Research Institute (EPRI) examination technique specification sheets. It further specified assessment of appropriateness of tubes selected for in-situ pressure testing, observation of in-situ pressure testing, and review of in-situ pressure test results. The inspectors did not observe in-situ pressure testing because none was required based on a review of the data.

The inspectors selected and reviewed the Acquisition Technique Sheets and their qualifying EPRI Examination Technique Specification Sheets to verify that the essential variables regarding flaw sizing accuracy had been identified and qualified through demonstration.

The inspection procedure specified comparing the estimated size and number of tube flaws detected during the current outage against the previous outage operational assessment predictions to assess PG&E's prediction capability. The inspectors reviewed PG&E's report, "Steam Generator Tubing Degradation Assessment for Diablo Canyon Unit 2 Refueling Outage 2R12, October 2004." The purpose of the assessment is to identify degradation mechanisms and for each mechanism to determine proper detection technique, determine number of tubes, establish structural limits, and establish flaw growth rates.

The inspection procedure specified confirmation be made that the steam generator tube eddy-current testing scope and expansion criteria meet Technical Specification requirements, EPRI guidelines, and commitments made to the NRC. The inspectors' review determined that the steam generator tube eddy-current testing scope and expansion criteria were being met.

The inspection procedure also specified that, if PG&E identified new degradation mechanisms, then verify that PG&E had fully enveloped the problem in an analysis and had taken appropriate corrective actions before plant startup. At the time of this inspection, no new degradation mechanisms had been identified.

The inspection procedure also required confirmation that all areas of potential degradation were being inspected, especially areas which were known to represent potential eddy-current testing challenges (e.g., top-of-tubesheet, tube support plates, and U-bends). The inspectors confirmed that all known areas of potential degradation, including eddy-current testing-challenged areas, were included in the scope of inspection and were being inspected.

The inspection procedure further required that repair processes being used were approved in the Technical Specification for use at the site. At the time of this inspection, PG&E had not performed or used the designated Technical Specification-approved repair processes, thus, there was no opportunity to observe implementation of any potential repairs (e.g., plugging operations). The inspectors also verified that none of the flawed tubes identified by PG&E required in-situ pressure testing.

The inspection procedure also required confirmation that the Technical Specification plugging limit was being adhered to, and determination whether depth sizing repair criteria were being applied for indications other than wear or axial primary water stress corrosion cracking in dented tube support plate intersections. The inspectors confirmed that PG&E adhered to these specifications.

The inspection procedure stated that if steam generator leakage greater that 3 gallons per day was identified during operations or during post-shutdown visual inspections of the tubesheet face, then assess whether PG&E had identified a reasonable cause and corrective actions for the leakage based on inspection results. The inspectors did not conduct any assessments because this condition did not exist.

The inspection procedure required confirmation that the eddy-current testing probes and equipment were qualified for the expected types of tube degradation and assessment of the site-specific qualification of one or more techniques. The inspectors observed portions of all eddy-current testing performed. During these examinations, the inspectors verified that (1) the probes appropriate for identifying the expected types of indications were being used, (2) probe position location verification was performed, (3) calibration requirements were adhered to, and (4) probe travel speed was in accordance with procedural requirements. The assessment of site-specific qualifications of the techniques being used, including a listing of the specific techniques and qualifications reviewed, is addressed and identified in the table above.

Finally, the inspection procedure specified the review of one to five samples of eddy-current testing data if questions arose regarding the adequacy of eddy-current testing data analyses. The inspectors did not identify any results where eddy-current testing data analyses' adequacy was questionable.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed 10 inservice inspection-related condition reports issued during the current and past refueling outage, and verified that PG&E identified, evaluated, corrected, and trended problems. In this effort, the inspectors evaluated the effectiveness of PG&E's corrective action process, including the adequacy of the technical resolutions.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Licensed Operator Requalification

a. Inspection Scope

On December 14, 2004, the inspectors witnessed one operator requalification exam in the simulator. The scenario involved a loss of a nuclear instrument, a trip of a main feed pump, and a steam generator tube rupture coincident with a stuck open steam generator safety valve. 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 PG&E staff.

b. Findings

No findings of significance were identified.

.2 Biennial Inspection

a. Inspection Scope

The inspector reviewed the annual operating examination test results for 2004. Since this was the first half of the biennial requalification cycle, PG&E had not yet administered the written examination. These results were assessed to determine if they were consistent with NUREG 1021, "Operator Licensing Examination Standards for Power Reactors," Revision 8, Supplement 1, guidance and Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process," requirements. This review included examination of test results, which included 2 scenario group failures out of 15 total groups and 2 job performance measures individual failures out of a total of 79 licensed operators. All personnel who failed were remediated and retested prior to return to watch standing duty.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors performed three inspection samples of PG&E'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 13, was used as guidance. The inspectors reviewed the following Action Requests.

- A0618134, "Maintenance Rule Performance Criteria, Goal Setting Review," for Units 1 Auxiliary Building Heating Ventilation and Air Conditioning System

- A0618135, "Maintenance Rule Performance Goal Setting Review," for Unit 2 Diesel Engine Generator 2-2

- A0613767, "Maintenance Rule Performance Goal Setting Review," for Unit 1 Nuclear Instrumentation System

b. Findings

No findings of significance were identified.

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

The inspectors performed two inspection samples of maintenance risk assessments and one inspection sample of emergent work control.

.1 Risk Assessments

a. Inspection Scope

The inspectors reviewed daily work schedules and compensatory measures to confirm that PG&E had performed proper risk management for routine work. The inspectors considered whether risk assessments were performed according to their procedures and whether PG&E 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) Preventive maintenance on Valve SW-1-FCV-601 and the associated inoperability of Auxiliary Saltwater Pump 1-2 on October 7, 2004.

- (Unit 2) Performance testing of Component Cooling Water Heat Exchanger 2-1, inoperability of Containment Fan Cooler Unit 2-5, and maintenance on the Morro Bay/Midway 1 Transmission line on October 8.

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 1) Diesel Engine Generators 1-2 and 1-3 starting air compressor crossties to turbo air receivers (ARs A0622861 and A0622997)

b. Findings

No findings of significance were identified.

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

.1 Unit 2 Feedwater Heater 2-2B Transient

a. Inspection Scope

On December 23, 2004, Unit 2 experienced a feedwater transient when feedwater Heater 2-2B tripped on high level. The cause of the high level in feedwater Heater 2-2B was a worn groove in an air flapper for the pneumatic level controller. As a result of the defective air flapper, the level controller failed to keep condensate from reaching a high level in the feedwater heater. Observable effects to the plant included increased condensate flow, a perturbation in main feedwater pump suction pressure, and a decrease in the heater tank level.

The inspectors reviewed operator actions, equipment performance, applicable procedures and plant records (equipment strip charts). The inspectors also interviewed operations personnel, reviewed the event for level of investigatory response, corrective actions, violation of NRC requirements, and generic issues.

b. Findings

Introduction. An unresolved item was identified for review of the feedwater heater high level trip alarm response procedure. Specifically, the inspectors are reviewing the adequacy of the alarm response procedure to respond to abnormal conditions involving the feedwater heaters.

Description. On December 23, 2004, operators received Alarm PK 10-21, Input 646, feedwater Heater 2-2B high level trip. The Unit 2 shift foreman dispatched the work control lead (senior reactor operator) and turbine building nonlicensed operator to investigate the cause of the alarm. The control room operators entered Alarm Procedure AR PK 10-21, Feedwater Htrs High Lvl Trip, Revision 4, when the alarm annunciated and took actions to trip the reactor if necessary. The control room operators observed the condensate flow increased as the No. 2 heater drain tank level and main feedwater pump suction pressure decreased. The work control lead was instructed to investigate the cause of the feedwater heater high level trip alarm and noticed that the level was high out-of-sight and the controlling air pressure to the level control valve was low.

The work control lead observed that feedwater Heaters 2-2A and 2-2C were within their normal operating band. Subsequently, he adjusted the setpoint for the level controller to increase the controlling air pressure. This action opened the level control valve further and allowed the condensate level within the feedwater heater to return to normal. The work control lead's statement indicated that he was proceeding to contact the control room after adjusting the level controller that the level in the feedwater heater was high out-of-sight when he was notified by two others in the area that the level was decreasing. As control room operators waited to hear from the operators at the feedwater heater, the feedwater heater high level trip alarm cleared and the work control lead reported that the level was in normal range. After the high level trip alarm cleared, control room operators learned that the level in feedwater Heater 2-2B was high out-of-sight for approximately two minutes before the work control lead was able to bring the level back within normal range

The inspectors reviewed Procedure AR PK 10-21 and noted that the diagnosis for a feedwater heater tube break consisted of an indicated increase in condensate flow concurrent with the feedwater heater level indication out-of-sight high. If only the level indication was observed to be out-of-sight high then the problem may be due to a malfunction of the level control system. However, a failed level controller, or a fail-closed level control valve, would give the same indications of a feedwater heater tube rupture; specifically an increase in condensate flow and an out-of-sight high condensate level in the feedwater heater. The actions associated with a feedwater heater tube leak would involve initiating a reactor trip and closing the main steam isolation valves, with the shift foreman's concurrence. A feedwater level controller malfunction provides other verification steps to check the normal drain valve open and the dump valve is controlling level in the sight glass. The operator actions also includes lowering the drain tank level.

The inspectors noted that Step 5.1.1 stated that "if flow has not increased, then the high level condition may be due to a malfunction of the level control system," and "if flow has increased, this could be an indication of a tube leak." The inspectors determined that these statements in the procedure provided diagnostic information to the operators, namely an increase in condensate flow and a high out-of-sight level on the feedwater heaters, as evidence of a feedwater heater tube rupture, however, these conditions were also evident for the feedwater level controller malfunction. The inspectors determined that with the information provided in the procedure and the plant conditions, that there was sufficient evidence to result in the shift foreman deciding to trip the reactor and close the main steam isolation valves. Furthermore, the inspectors observed that PG&E had not developed a procedural bases for the actions specified by Step 5.1.1. A human performance crosscutting aspect (resources) was identified for the inadequate alarm procedure. The inspectors are reviewing the adequacy of alarm response Procedure AR PK 10-21 to address a feedwater heater level control malfunction as an unresolved item.

Analysis. No analysis was performed for this unresolved item.

Enforcement. Unresolved Item (URI) 50-323/04-05-03, Adequately of Alarm Procedure For Feedwater Heater Level Control Malfunctions.

.2 Unit 2 Spent Fuel Pool (SPF) Level Drop

a. Inspection Scope

On December 23, 2004, the Unit 2 SPF level dropped approximately 4 inches as a result of Valve SFS-2-3, SFP skimmer pump casing drain to miscellaneous equipment drain tank, being left open following a filter replacement. The inspectors observed operator actions and equipment performance following the event. The inspectors also interviewed operations personnel and reviewed the event for corrective actions, violation of requirements, and generic issues.

b. Findings

Introduction. A Green, self-revealing NCV was identified for the failure to appropriately implement the procedure for SFP skimmer filter replacement, as required by Technical Specification 5.4.1.a. This failure resulted in a loss of approximately 36,000 gallons of water from the SFP.

Description. On December 23, 2004, operators implemented Clearance 79718 for replacing the SFP skimmer filter. Attached to the clearance was Procedure OP B-7:III, “Spent Fuel Pool System - Shutdown and Clearing and Filter Replacement,” Revision 15. Section 6.3.1 of the procedures for shutting down and clearing the skimmer pump and strainer had been marked for implementation. Following the implementation of the clearance, the work control lead observed that Section 6.3.1 of Procedure OP B-7:III was used, when Section 6.3.2, steps ‘a’ through ‘e’, should have been used. Section 6.3.2 of the procedure specifically addressed replacement of the SFP skimmer filter. The work control lead marked steps ‘g’ through ‘l’ of Section 6.3.2

for returning the SFP skimmer pump back to service. He noticed that, because Section 6.3.1 had been used to clear the pump, 4 valves would be potentially mis-positioned. The work control lead discussed the potential for the 4 valves to be potentially mis-positioned with the oncoming shift work control lead.

Following SFP skimmer filter replacement, the oncoming shift work control lead informed operators to restore the SFP skimmer system using Section 6.3.2. The work control lead also informed the operators that he was not sure how the SFP skimmer system had been cleared by the previous shift. Operators restored the SFP skimmer system, and when they started the system, they found 3 valves mis-positioned. Approximately 3 hours later operators noticed a steady increasing level in the miscellaneous equipment drain tank. Operators then found that Valve SFS-2-3 was still mis-positioned from the clearance of the skimmer pump. For the 3 hours that Valve SFS-2-3 was mis-positioned, approximately 36,000 gallons of water was drained from the SFP.

The inspectors determined that PG&E failed to properly implement Procedure OP B-7:III when clearing the SFP skimmer system. Section 6.3.2 specifically addressed replacement of the SFP skimmer filter. The inspectors also observed that other operators were aware of a potential mis-position of valves. However, the need for checking the alignment of these valves had not been adequately communicated to and/or carried out by the operators who restored the SFP skimmer system. The operators who restored the SFP skimmer system recognized and corrected the 3 mis-positioned valves, but failed to adequately investigate the reason for the mis-position, which was a missed opportunity to discover the 4th mis-positioned valve. A human performance cross cutting aspect was identified for the failure on two occasions to address configuration control concerns with the system.

<u>Analysis</u>. The performance deficiency associated with this event is the failure to properly implement Procedure OP B-7:III as required by Technical Specification 5.4.1.a. This deficiency impacted the Initiating Events Cornerstone that limit the likelihood of events that upset plant stability during shutdown and affected the configuration control attribute for operating equipment lineup. The finding was considered more than minor using Example 5.a of Inspection Manual Chapter 0612. Specifically, Valve SFS-2-3 was mis-positioned due to the use of the wrong section of Procedure OP B-7:III and then returned to service. Additionally, operators had two opportunities to identify the mis-positioning of Valve SFS-2-3 but failed to identify the condition. The mis-positioned valve resulted in a loss of approximately 36,000 gallons of water from the spent fuel pool. This finding was reviewed by NRC management in accordance with Inspection Manual Chapter 0609 and 0612 and determined to be of very low safety significance. This determination was based on the performance deficiency would not have resulted in a loss of spent fuel pool inventory below the Technical Specification required level on a loss of spent fuel pool cooling.

Enforcement. Technical Specification 5.4.1.a requires, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2. Item 3.h of Regulatory Guide 1.33, Appendix A recommends procedures for startup, operation, and shutdown of fuel storage pool purification and cooling systems. Contrary to the above, PG&E failed to properly implement Procedure OP B-7:III with regards to replacing the SFP skimmer filter. The failure to properly implement this procedure resulted in mis-position of Valve SFS-2-3 and the loss of approximately 36,000 gallons of water from the SFP. Because the failure to properly implement Procedure OP B-7:III is of very low safety significance and has been entered into the corrective action system as AR A0628635, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/04-05-04, Failure to Properly Implement Procedure for Spent Fuel Pool Skimmer Filter Replacement.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed seven inspection samples of operability evaluations. These reviews of operability evaluations and/or prompt operability assessments and supporting documents were performed to determine if the associated systems could meet their intended safety functions despite the degraded status. The inspectors reviewed the applicable Technical Specification, Codes/Standards, and Final Safety Analysis Report Update sections in support of this inspection. The inspectors reviewed the following AR's and operability evaluations:

- (Unit 2) Environmental qualification of auxiliary feedwater flow indication cable (ARs A0620857, A0621502)
- (Unit 1) Emergency core cooling system (ECCS) voiding (AR A0621502)
- (Unit 1) Startup Transformer 1-1 automatic tap changer in manual due to unexpected step increases (AR A0625650)
- (Unit 2) Residual Heat Removal Pump 2-2 socket weld crack at suction pressure instrument line (AR A0624790)
- (Units 1 and 2) Valve FW-2-LCV-110 failed closed (AR A0624790)
- (Unit 2) DEG 2-3 lube oil instrument line crack (AR A0617419)
- (Unit 1) Small water drip on feedwater pipe lead 2-2 (AR A0628484)

b. Findings

1. Introduction. The inspectors identified a Green NCV for the failure to take adequate corrective actions to prevent the ECCS void space from exceeding the volume allowed by plant procedures. The void space volume caused operators to declare the ECCS inoperable and enter Technical Specification 3.0.3 twice on October 21, 2004.

Background. The ECCS shares components of the normal charging system. The charging system consists of two centrifugal charging pumps (CCPs), one positive displacement pump (PDP), the volume control tank and associated piping, valves, and instrumentation. A hydrogen concentration is maintained in the reactor coolant at a level of approximately 35 cc/kg to scavenge oxygen in the primary coolant system. During normal system operation, gases come out of solution at the reactor coolant pump seals due to the large pressure drop from the high pressure primary system to the low pressure pump seal leak-off return line and due to the low pressure and high temperature in portions of the pump seal return line. When these gases come out of solution, they form voids in the piping system. The presence of large voids can result in gas binding of pumps, resulting in the loss of pump flow. With a CCP in operation, the high flow rates entrain the gas bubbles and prevent the formation of voids in the piping system. When the PDP is placed in service, the seal return line flow is reduced allowing some of the entrained gases to accumulate in the stagnant CCP miniflow recirculation line. This gas void can then be transported to the piping upstream of Valves 8807A/B when a CCP is again placed in service.

In November 1998, Calculation STA-089, “Allowable Accumulated Gas Volume in the CCP’s and SIP’s [safety injection pump] Suction Cross-Tie Piping,” Revision 0, was developed based on industry experience. The calculation was revised in 1999 and 2000 to include allowable gas accumulation near Valves 8804A and 8807A/B. Parallel Valves 8807A/B are located in the high point of the cross-tie section of the CCP’s and safety injection pump suctions.

On May 14, 2004, during performance of Procedure STP M-89 (Unit 2), “ECCS System Venting,” Revision 31, a void volume was discovered which exceeded the allowable volume stated in Calculation STA-089. The void caused operators to enter Technical Specification 3.0.3 for Unit 2 and vent the affected section of piping in order to return the system to operable status.

In July 2004, a revision to Procedure OP B-1A:V (Unit 1), “CVCS - Transfer of Charging Pumps,” Revision 19, was incorporated to include void monitoring requirements recommended by Calculation STA-108. The procedure change required monitoring of the piping on a shiftly basis for three days following switching from PDP to CCP operation. This was done as an interim corrective action to identify void formation prior to exceeding the allowable limits.

Description. On October 21, 2004, following transfer from PDP 1-3 to CCP 1-2, a void was identified at Valves SI-1-8807A/B during performance of Procedure OP B-1A:V. The water level was determined to be 4.05 inches with a minimum allowed level of 4.5 inches. Unit 1 entered Technical Specification 3.0.3 at 9:52 a.m. and operators proceeded to vent the piping. Unit 1 exited Technical Specification 3.0.3 at 10:08 a.m. Approximately two hours later, at 12:03 p.m., the void space was monitored and found to be 4.45 inches. Technical Specification 3.0.3 was again entered until the piping was vented and the system declared operable at 12:07 p.m.

Analysis. The performance deficiency associated with this finding is the failure to take effective corrective action to prevent the formation of a gas void that exceeded the volume allowed by station procedures. The finding involved the Mitigating System cornerstone to ensure the availability, reliability and capability of systems that respond to initiating events and affected the equipment performance attribute. The finding is greater than minor because it is similar to Example 2.f in Appendix E of Inspection Manual Chapter 0612. Similar to the example, the void size had exceeded the limit described in Calculation STA-108. Using the Inspection Manual Chapter 0609 Phase 1 Screening Worksheet, the finding was of very low safety significance (Green) since the finding is not a design or qualification deficiency that has been confirmed to result in a loss of function per Generic Letter 91-18.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions,” 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 nonconformance are promptly identified and corrected. Contrary to the above, PG&E failed to incorporate adequate corrective actions to prevent the void volume from exceeding the procedural limit. Because this failure to apply adequate corrective actions is of very low safety significance and has been entered into PG&E’s corrective action program (AR A0621238), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/04-05-05, Failure to Adequately Correct ECCS Voiding Following Operation of the Positive Displacement Pump.

2. Introduction. The inspectors identified an unresolved item for the failure to promptly correct a cracked lube oil instrument sensing line, as required by 10 CFR Part 50, Appendix B, Criterion XVI. As a result, there was an increased potential for DEG 2-3 to trip on low lube oil level.

Description. On August 29, 2004, operators discovered a lube oil leak coming from the welded connection of Valve DEG-2-1084 to the downstream 3/8 inch instrument line. The instrument line connected the lube oil system to pressure switch PS-237. The pressure switch provided a low pressure alarm for the pre-circulation lube oil pump. PG&E decided to correct the leak in the next available maintenance outage window, which would be in Refueling Outage 2R12. Additionally, in AR A0617419, engineers did not consider the leak to affect the operability of DEG 2-3 and no formal prompt operability assessment was performed at that time.

Following the Parkfield earthquake on September 28, 2004, operators initiated a test run of the Unit 1 and 2 DEGs to verify their capability start and run. During the pre-firing checks for DEG 2-3, it was noted that the oil leak had grown significantly (approximately 12 drops per minute). Following discussions between operations, maintenance, and engineering personnel, DEG 2-3 was declared inoperable. Operators subsequently closed Valve DEG 2-1084, which isolated the leak. DEG 2-3 was again considered operable under a prompt operability assessment documented in AR A0617419. The cracked instrument line was replaced on October 2, 2004.

PG&E personnel performed a failure analysis of the cracked tubing and determined that the crack initiated at the toe of the weld and was the result of high-cycle fatigue. The crack was circumferential at the toe of the weld, and was through-wall for half of the tubing's outer diameter. The source of the stress that created the crack was the unsecured mass of Valve DEG-2-1084 and vibration from the pre-circulation lube oil pump at standby and the DEG when it was in operation. PG&E personnel evaluated the crack and determined that it would have minor impact on DEG 2-3 operation. This evaluation was based on the estimated force to completely break the cracked tubing (30 to 40 pounds) and the calculated leakrate at an operating lube oil pressure of 90 psig, as compared to a standby lube oil pressure of 15 psig. Engineers calculated the leakrate to be 0.0015 gph at a lube oil pressure of 90 psig. Based on this leakrate, and the lube oil low level alarm setpoint of 110 gallons, engineers estimated 107,000 hours of operation before the alarm would activate.

The inspectors performed an independent evaluation of the cracked tubing's impact on DEG 2-3. Based on the fact that DEG 2-3 only operated approximately 2 hours between the time the leak was discovered and the time DEG 2-3 was declared inoperable, the inspectors observed that the crack had propagated quickly; primarily from the vibration of the pre-circulation lube oil pump only. The inspectors surmised that there was an increased probability that the instrument tube would completely severe under several hours of DEG 2-3 operation. The inspectors, and PG&E personnel, calculated that if the tubing severed, and was not obstructed, then the leakrate would become 10 to 15 gpm. However, based on the mounting of the tubing it was determined that if the tubing were to completely severe, the flow out of Valve DEG-2-1084 would be obstructed by instrument tubing and the resulting flow would be 1 to 3 gpm. PG&E estimated that DEG 2-3 could sustain a loss of 200 gallons of lube oil before damage to the engine began and/or the engine shutdown on low-low lube oil pressure. The low lube oil level alarm would become active after DEG 2-3 lost 170 gallons of lube oil. Assuming no operator intervention before the low lube oil level alarm became active, operators would have 10 to 30 minutes to respond to DEG 2-3 and isolate Valve DEG-2-1084. The inspectors determined that operators would be able to respond to such a scenario in a timely manner to prevent damage to DEG 2-3.

Analysis. The performance deficiency associated with this event is the failure to correct a cracked lube oil instrument tubing downstream of Valve DEG-2-1084. This deficiency impacted the Mitigating Systems Cornerstone for reliability of systems that respond to initiating events to prevent undesirable consequences and affects the equipment performance attribute. The finding was and is more than minor using Example 4.f of Inspection Manual Chapter 0612, Appendix E. Similar to Example 4.f, the inspectors determined that there was impact to DEG 2-3 operability. Using the SDP Phase 1 screening worksheets in Appendix A of Inspection Manual Chapter 0609, the finding was determined to be potentialy greater than very low safety significance because the failure could have resulted in an actual loss of safety function of DEG 2-3.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, 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 nonconformance are promptly identified and corrected. Contrary to the above, PG&E failed to promptly correct the cracked lube oil instrument tubing on DEG 2-3. Specifically, PG&E observed the crack, but did not adequately assess the growth rate of the crack or its potential impact on DEG 2-3 operability. The failure to promptly correct the lube oil instrument tubing is of very low safety significance and has been entered into the coretive action system as AR A0617419. This is an unresolved item URI 50-323/04-05-06, Failure to Promptly Correct Diesel Engine Generator Lube Oil Instrument Line Crack, pending completion of the safety significance determination.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed two individual operator workarounds and performed one cumulative-effects review during this inspection period. An operator workaround is an operator action taken to compensate for a degraded or nonconforming condition that complicates the operation of plant equipment. The cumulative effect evaluation assessed the impact of all operator workarounds on the operator's ability to respond in a correct and timely manner to plant transients and emergency situations. The individual workarounds evaluated were:

- Auxiliary salt water heat exchanger differential pressure indicator
- Steam dump setpoint

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed six post-maintenance 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 were compared to the Technical Specification and the Final Safety Analysis Report-Update. Additionally, the inspectors verified the tests were adequate for the scope of work and were performed as prescribed, jumpers and test equipment were properly removed after testing, and test equipment range, accuracy, and calibration were consistent for the application. The following selected maintenance activities were reviewed by the inspectors:

- (Unit 2) Diesel Engine Generator 2-3 lube oil filter housing O-ring replacement on July 12, 2004, (Work Order C0186068)

- (Unit 2) Source Range Nuclear Instrument N-32 detector and moderator replacement on October 30, 2004, (Work Order C0184572)

- (Unit 2) Actuator replacement for steam lead 3 supply valve, MS-2-FCV-38, to the turbine-driven auxiliary feedwater pump on October 26, 2004, (Work Order C0189735)

- (Unit 2) Air hose replacement for main steam isolation bypass valve MS-2-FCV-25 on November 18, 2004, (Work Order R0260881)

- (Unit 2) Position switch calibration for main steam isolation bypass valve MS-2-FCV-24 on November 23, 2004, (Work Order R0260827)

- (Unit 2) Position switch replacement for steam generator blowdown isolation valve MS-2-FCV-762 on November 29, 2004, (Work Order C0192771)

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors witnessed and evaluated PG&E's performance during the 12th refueling outage for Unit 2. The outage lasted from October 25 to December 16, 2004. Before and during the outage, the inspectors evaluated PG&E's consideration of risk in developing outage schedules; use of risk reduction methodologies in control of plant configurations; development of mitigation strategies for losses of key safety functions; and adherence to the operating license and Technical Specification requirements. Specifically, the inspectors observed PG&E's actions in the following areas:

- Outage risk control plan prior to, and during, implementation
- Mode transitions from power operation (Mode 1) to reactor vessel de-fueled, and then the return to power operation
- Defense-in-depth and handling of unexpected conditions
- Plant configuration control, particularly clearance of equipment
- Supply and control of electrical power with regards to Technical Specification requirements and outage risk plans
- Adequacy of decay heat removal for the reactor vessel, refueling cavity, and spent fuel pool
- Fuel assembly movement, tracking, and inspections
- Containment closure and containment closure capability with respect to the Technical Specification and outage risk plans
- Adequate control of reduced inventory and midloop conditions
- Movement of heavy loads inside containment and the turbine building

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors evaluated eight routine surveillance tests to determine if PG&E complied with the applicable Technical Specification requirements to demonstrate that equipment was capable of performing its intended safety functions and operational readiness. Included in the seven samples, one surveillance test involved a reactor coolant system leak detection system and one surveillance test was also an inservice test. 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:

- (Unit 2) Procedure STP M-9A, "Diesel Engine Generator Routine Surveillance Test," Revision 68, for DEG 2-3
- (Unit 2) Reactor Coolant System Leak Detection Procedure STP I-65, "Containment Fan Cooler Collection Monitoring System Calibration," Revision 5A for CFCU 2-3
- (Unit 2) Procedure STP M-13H, "4KV Bus H Non-SI Auto-Transfer Test," Revision 26
- (Unit 2) Procedure STP M-15, "Integrated Test of Engineered Safeguards and Diesel Generators," Revision 38
- (Unit 2) Procedure STP V-8, "Slave Relay Test and Time Response of MSIV, MSIV Bypass, and Steam Generator Blowdown Valves," Revision 13
- (Unit 1) Procedure STP I-36-S3R13, "Protection Set III, Rack 13 Channels Operational Test," Revision 12
- (Unit 2) Procedure STP V-7B, "Test of Engineered Safeguards, Valve Interlocks and RHR Pump Trip for RWST Level Channels," Revision 23
- (Unit 2) Inservice Test Procedure STP P-AFW-21, "Routine Surveillance Test of Turbine-Driven Auxiliary Feedwater Pump 2-1," Revision 17

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP1 Exercise Evaluation (71114.01)

a. Inspection Scope

The inspectors reviewed the objectives and scenario for the 2004 Biennial Emergency Preparedness Exercise to determine if the exercise would acceptably test major elements of the emergency plan. The scenario included a large and sudden loss-of-reactor coolant to the reactor containment, with subsequent loss-of-coolant makeup and injection sources, resulting in fuel cladding damage. A containment over-pressure condition resulted in the rupture of a containment penetration, resulting in an ongoing radioactive steam release to the environment. The licensee activated all of their emergency facilities to demonstrate their capability to implement the emergency plan.

The inspectors evaluated exercise performance by focusing on the risk-significant activities of classification, notification, protective action recommendations, and assessment of offsite dose consequences in the simulator control room and the following emergency response facilities:

- Technical Support Center
- Operations Support Center
- Emergency Operations Facility

The inspectors also assessed personnel recognition of abnormal plant conditions, the transfer of emergency responsibilities between facilities, communications, protection of emergency workers, emergency repair capabilities, and the overall implementation of the emergency plan to verify compliance with the requirements of 10 CFR 50.47(b), 10 CFR 50.54(q), and Appendix E to 10 CFR Part 50.

The inspectors attended the postexercise critiques in each of the above emergency response facilities to evaluate the initial licensee self-assessment of exercise performance. The inspectors also attended the formal presentation of critique items to plant management. The inspectors completed one sample during the inspection.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspector reviewed changes made to Revision 4 of the Diablo Canyon Emergency Plan, submitted in April, 2004. The revision change included Change 5 to Section 5, Change 4 to Sections 4 and 7, Change 3 to Section 6, Change 2 to Sections 1, 2, and 8, and Change 1 to Appendix A. In addition to several administrative changes, the revision change modified the notification process for the emergency response organization to clarify that during an actual alert declaration, all emergency response organization personnel will be called to respond to the declared emergency. The revision change also clarified the onsite personnel accountability process, relocated the onsite support center to the office area at the southern end of the technical support center, removed the operations simulator UHF system radio broadcast function console due to an upgrade of health physics communications equipment to satellite phones, and replaced fluorescent lightning fixtures in the auxiliary building with metal halide fixtures to improve plant lighting.

The revision change was compared to the previous revisions, to the criteria of NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, to the requirements of 10 CFR 50.47(b) and 50.54(q), and to Diablo Canyon Procedure AWP EP-004, "10 CFR 50.54(q) Guidance," Revision 0, to determine if the revisions were made consistent with the regulations. The inspector completed one sample during the inspection.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY
Cornerstone: Occupational Radiation Safety

2OS1 Access Control To Radiologically Significant Areas (71121.01)

a. Inspection Scope

This area was inspected to assess PG&E's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas (HRAs), and worker adherence to these controls. The inspectors used the requirements in 10 CFR Part 20, the Technical Specification, and PG&E's procedures required by Technical Specification as criteria for determining compliance. During the inspection, the inspector interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspectors performed independent radiation dose rate measurements and reviewed the following items:

- Performance indicator events and associated documentation packages reported by PG&E in the Occupational Radiation Safety Cornerstone

- Controls (surveys, posting, and barricades) of the Auxiliary Building, Spent Fuel Building, Radwaste Building, and Containment Building radiation, high radiation, and airborne radioactivity areas

- Radiation work permit, procedure, engineering controls, and air sampler locations

- Conformity of electronic personal dosimeter alarm set points with survey indications and plant policy; workers' knowledge of required actions when their electronic personnel dosimeter noticeably malfunctions or alarms

- Barrier integrity and performance of engineering controls in two potential airborne radioactivity areas

- Adequacy of PG&E's internal dose assessment for one actual internal exposure greater than 50 millirem CEDE

- Physical and programmatic controls for highly activated or contaminated materials (nonfuel) stored within spent fuel and other storage pools

- Self-assessments and audits related to the access control program since the last inspection

- Corrective action documents related to access controls

- Licensee actions in cases of repetitive deficiencies or significant individual deficiencies

- Radiation work permit briefings and worker instructions

- Adequacy of radiological controls such as required surveys, radiation protection job coverage, and contamination controls during job performance

- Dosimetry placement in high radiation work areas with significant dose rate gradients

- Changes in licensee procedural controls of high dose rate - high radiation areas and very high radiation areas

- Controls for special areas that have the potential to become very high radiation areas during certain plant operations

- Posting and locking of entrances to all accessible high dose rate - high radiation areas and very high radiation areas

- Radiation worker and radiation protection technician performance with respect to radiation protection work requirements

The following items were not available to be reviewed by the inspector:

- Licensee event reports, and special reports related to the access control program since the last inspection

b. Findings

1. Introduction. The inspectors reviewed a self-revealing, noncited violation of Technical Specification 5.7.2. resulting from PG&E's failure to correctly lock a high radiation area with dose rates greater than 1 rem per hour. The violation had very low safety significance.

Description. On November 14, 2004, workers accessed the steam generator platforms to remove the bowl suction fixtures from the hot and cold legs of all four steam generators. Before removal of the suction hoses, the workers were able to demonstrate to a radiation protection technician that the lower access flaps of the shield doors could be opened far enough to remove the suction fixtures with the locking mechanism still in place. With the lower flaps open, an individual could expose a portion of the whole body (arm above the elbow) to dose rates greater than 1 rem per hour, according to PG&E's radiation surveys. The locking mechanism was the method used by PG&E to comply with the Technical Specification requirements for control of a high radiation area containing dose rates greater than 1 rem per hour; however, this control was shown to be ineffective. The locking mechanisms were installed incorrectly.

Analysis. The failure to correctly control a high radiation area is a performance deficiency. The finding is greater than minor because it is associated with one of the cornerstone attributes (exposure control) and affected the cornerstone objective because it could have resulted in unplanned, unintended radiation dose. The finding involved the potential for workers to receive significant, unplanned, unintended doses as a result of conditions contrary to Technical Specification requirements; therefore, the inspector used the Occupational Radiation Safety SDP described in Manual Chapter 0609, Appendix C, to analyze the significance of the finding. The inspectors determined that the finding was of very low significance because (1) it was not an ALARA finding, (2) it was not an overexposure, (3) it did have a substantial potential for overexposure, and (4) it did not compromise the ability to assess doses.

In addition, this finding had crosscutting aspects associated with human performance. When the individuals failed to correctly install the locking mechanism, it directly contributed to the finding.

Enforcement. Technical Specification 5.7.2.a. states, in part, that High Radiation Areas with dose rates greater than 1 rem per hour at 30 cm from the radiation source or from any surface penetrated by the radiation, but less than 500 rads per hour at 30 cm from the radiation source or from any surface penetrated by the radiation, each entryway to such an area shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry. PG&E violated this requirement when it used an ineffective method of preventing unauthorized access to areas inside the steam generators with dose rates greater than 1 rem per hour. The finding was documented in PG&E's corrective action program as AR A0624199. Because this violation was of very low safety significance and was entered into PG&E's corrective action program, it is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/04-05-07, Failure to lock a high radiation area with dose rates greater than 1 rem per hour.

2. Introduction. The inspectors reviewed a self-revealing, noncited violation of Technical Specification 5.7.2, resulting from PG&E's failure to control entry into a high radiation area with dose rates greater than 1 rem per hour through the use of the correct radiation work permit. The violation had very low safety significance.

Description. On July 31, 2004, a radiation protection technician and a reactor operator entered the reactor containment building and went to Reactor Coolant Pump Cubicle 2-4 to check the pump oil level. The objective was to observe the sight glass from the cubicle labyrinth. The entry was authorized by a radiation protection foreman, who instructed the two individuals to use Radiation Work Permit 04-0002. The radiation work permit limited the total dose to 25 millirems and limited the entry into areas with dose rates of no more than 1 rem per hour.

Upon reaching the Reactor Coolant Pump cubicle labyrinth, the two individuals found that they could not see the sight glass as anticipated. The radiation protection technician surveyed the work area inside the cubicle, identified general area dose rates of 6 rem per hour, informed the operator, and decided the work could progress. The two individuals exited the work area with dose and dose rate alarms. As a result, PG&E determined that control of a high radiation area with dose rates greater than 1 rem per hour had not been correctly implemented.

Analysis. The failure to correctly control a high radiation area is a performance deficiency. The finding is greater than minor because it is associated with one of the cornerstone attributes (exposure control) and affected the cornerstone objective because it could have resulted in unplanned, unintended radiation dose. Because the finding involved the potential for workers to receive significant, unplanned, unintended doses as a result of conditions contrary to Technical Specification requirements, the inspector used the Occupational Radiation Safety SDP described in Manual Chapter 0609, Appendix C, to analyze the significance of the finding. The inspector determined that the finding was of very low significance because (1) it was not an ALARA finding, (2) it was not an overexposure, (3) it did have a substantial potential for overexposure, and (4) it did not compromise the ability to assess doses.

In addition, this finding had crosscutting aspects associated with human performance. When the individuals failed to follow the correct radiation work permit, it directly contributed to the finding.

Enforcement. Technical Specification 5.7.2.a. states, in part, that High Radiation Areas with dose rates greater than 1 rem per hour at 30 cm from the radiation source or from any surface penetrated by the radiation, but less than 500 rads per hour at 30 cm from the radiation source or from any surface penetrated by the radiation, the access to, and activities in, each such area shall be controlled by means of a radiation work permit. PG&E violated this requirement when the radiation protection technician and the reactor operator used the incorrect radiation work permit to access an area with dose rates greater than 1 rem per hour. The finding was documented in PG&E's corrective action program as Action Request 615777. Because this violation was of very low safety significance and was entered into PG&E's corrective action program, it is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/04-05-08, Failure to access a high radiation area with dose rates greater than 1 rem per hour with the correct radiation work permit.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Reactor Safety Performance Indicator Verification

a. Inspection Scope

The inspectors verified six samples of performance indicators. The inspectors reviewed these indicators for the period from the fourth quarter of 2003 through the third quarter of 2004 to assess the accuracy and completeness of the indicator. The inspectors reviewed plant operating logs and PG&E 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. The following performance indicators were verified:

- Safety System Failures
- Reactor Coolant System Activity
- Reactor Coolant System Identified Leakage

b. Findings

No findings of significance were identified.

.2 Occupational Radiation Safety Performance Indicator Verification

a. Inspection Scope

The inspectors sampled licensee submittals for the performance indicators (PIs) listed below for the period from the first quarter 2003 through the third quarter 2004. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, were used to verify the basis in reporting for each data element.

- Occupational Exposure Control Effectiveness PI

  Licensee records reviewed included corrective action documentation that identified occurrences of locked high radiation areas (as defined in PG&E's Technical Specification), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned personnel exposures (as defined in NEI 99-02). Additional records reviewed included ALARA records and whole body counts of selected individual exposures. The inspectors interviewed licensee personnel that were accountable for collecting and evaluating the PI data. In addition, the inspectors toured plant areas to verify that high radiation, locked high radiation, and very high radiation areas were properly controlled.

- Public Radiation Safety

  - Radiological Effluent Technical Specification/Offsite Dose Calculation Manual
  - Radiological Effluent Occurrences

  Licensee records reviewed included corrective action documentation that identified occurrences for liquid or gaseous effluent releases that exceeded PI thresholds and those reported to the NRC. The inspectors interviewed PG&E personnel that were accountable for collecting and evaluating the PI data.

b. Findings

No findings of significance were identified.

.3 Emergency Preparedness Cornerstone:

a. Inspection Scope

The inspectors sampled submittals for the performance indicators listed below for the period from October, 2003, through September 30, 2004. The definitions and guidance of Nuclear Engineering Institute NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, were used to verify the licensee's basis for reporting each data element in order to verify the accuracy of performance indicator data reported during the assessment period.

- Drill and exercise performance
- Emergency response organization participation
- Alert and notification system reliability

The inspectors reviewed a 100 percent sample of drill and exercise scenarios, licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. The inspectors reviewed documentation related to three actual emergency declarations of a Notice of Unusual Event, all related to earthquakes that were monitored at the Diablo Canyon Plant. The inspectors reviewed the qualification, training, and drill participation records for a sample of 10 emergency responders. The inspectors reviewed alert and notification system maintenance records and procedures, and a 100 percent sample of siren test results. The inspectors also interviewed licensee personnel that were responsible for collecting and evaluating the performance indicator data. The inspectors completed three samples during this inspection.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Daily Reviews

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for followup, the inspectors performed a daily screening of items entered into the corrective action program (CAP). The review was accomplished by reviewing daily Action Request Review Team packages and attending daily Operations morning meetings.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the PG&E's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening and inspectors' review of daily plant status. Other information that was considered in the semi-annual trend review was licensee trending efforts and licensee human performance results. Particular items that were considered in this semi-annual trend report include:

- ARs associated with adverse trends
- Quarterly Trending Manager Reports
- Human performance error-free clock reset data
- Quality assurance audit reports
- System Health Reports

b. Findings

The inspectors reviewed the second period 2004 (June 1 to October 24) Quality Performance Assessment Report. The report discussed challenges seen in Unit 1 Refueling Outage 1R12 and, at the time of the report, challenges for preparing for Unit 2 Refueling Outage 2R12. Specific challenges mentioned included high workload and lower resources during the summer. The report mentioned self-assessments, management observations, operating experience trending, and bench marking programs as needing management attention and focus in the year 2005 for long-term improvements and sustained excellent performance to be achieved. Human performance issues, at the time of the report, tended to center on the Operations and Security departments. With respect to the corrective action program, the Corrective Action Review Board had been implemented, as well as the morning AR review meeting. The report discussed problem identification and resolution issues associated with troubleshooting and extent of condition issues related to Containment Spray Pump 2-2 grounds. The inspectors also reviewed quality assurance audits of the Emergency Planning and Operations departments, but no outstanding trends were noted.

The inspectors reviewed the 3rd Quarter Trending Manager Reports for equipment reliability and processes, procedures, and programs. The trending manager uses event trending report data to identify potential adverse trends at Diablo Canyon Power Plant. The tool was placed in full operation in the 4th quarter of 2003. The trending manager reports showed an increasing trend in maintenance preventable functional failures, with 117 failures in the last three quarters of 2003 and 178 in the first three quarters of 2004. Most of the maintenance preventable functional failures were related to diesel engine generators, ventilation systems, compressed air systems, plant annunciator, and doors.

The inspectors reviewed the following ARs associated with adverse trends identified by PG&E.

- A0609910, “Adverse Trend in Design Basis Documentation,” listed 9 ARs from Quality Assurance’s audit (Audit No. 040080101) of the diesel engine generators, which identified several inconsistencies between the design criteria memorandum, the calculations, and the design drawings. None of the inconsistencies were considered significant by Quality Assurance. Corrective actions included training and briefs with design engineering personnel to discuss the types of findings in the audit.

- A0609950, “Adverse Trend in Configuration Control,” listed 13 ARs that described discrepancies between the design documentation and the as-found installation and material condition of DEG components, impairment of fire barriers, incorrect component database entry, and inadequate documentation of DEG generator housing cracks. None of the discrepancies were determined by Quality Assurance to impact DEG operability.

- A0604597, “Adverse Trend in Printed Circuit Cards Solder Connections,” listed two nonconformance reports, two quality evaluations, and one AR that described issues with printed circuit card solder quality. Printed circuit card solder quality issues had been discovered on DEG control circuits, battery charger control circuits, and the solid-state protection system. Nonconformance report N0002181 was initiated to address the root cause and corrective actions for the poor solder quality.

- A0612564, “Potential Adverse Trend in Butterfly Valve Performance,” was generated by the Corrective Action Review Board based on past issues involving butterfly valve liner degradation and limit stop settings. PG&E had initiated an apparent cause analysis to address the past butterfly valve issues.

- A0618217, "Evaluate Adverse Trend in Corrosion Problems," was generated by reliability engineering based on equipment trend reports. The adverse trend revealed an increase from 20 corrosion problems in the 4th quarter 2003 to 42 in the 2nd quarter 2004. PG&E convened a panel of maintenance, engineering, and coatings personnel to discuss the aspects of the corrosion issues. The most affected equipment for corrosion was found at the intake structure, pipe racks, and on top of the auxiliary buildings. Lack of resources for re-coating surfaces and inadequate preventive maintenance were cited as the main causes of corrosion problems.

The inspectors reviewed the system health reports and observed that both the DEGs and fire protection equipment were in a yellow status, which required senior management's attention. The DEGs were in a yellow status due to a need for completing corrective actions associated with lube oil coking, auto-voltage regulator card replacement, and system availability exceeding plant administrative limits. The fire protection equipment was in yellow status due to a failure to fund long-term plans to resolve corrosion degradation in the system.

The inspectors reviewed the human performance event free clock reset trend and data. The event free clock reset trend is a 12 month-rolling average of the number of days between clock resets. For the later half of 2004, the trend has been constant with an average number of days between clock resets as 33 days. There were 11 clock reset events from December 2003 to November 2004. Six of the events occurred during refueling outages, 2 events were related to personnel injuries, and the other three events occurred outside refueling outages. The inspectors reviewed the non-injury events in the current inspection quarter, or previous inspection quarters.

.3 Occupational Radiation Safety

a. Inspection Scope

Section 2OS1 evaluated the effectiveness of PG&E's problem identification and resolution processes regarding access controls to radiologically significant areas and radiation worker practices. The inspectors reviewed selected corrective action documents for root cause/apparent cause analysis against PG&E's problem identification and resolution process.

b. Findings

No findings of significance were identified.

.4 Annual Sample Review

a. Inspection Scope

The inspectors reviewed all action requests (corrective action program inputs) associated with the last three emergency preparedness exercises. Action requests associated with event classification, notification of offsite authorities, and processes for providing protective action recommendations were reviewed in detail to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized.

b. Findings

No findings of significance were identified.

.5 Problem Identification and Resolution Crosscutting Aspects Identified Elsewhere in this Report

Section 1R04.2 identified a problem identification and resolution crosscutting aspect for the failure to promptly correct the reverse rotation of CFCUs over a 13 year time period.

Section 1R15 identified two problem identification and resolution crosscutting aspects for the failure to take adequate corrective actions to prevent the ECCS void space from exceeding the volume allowed by plant procedures and the failure to promptly correct a cracked lube oil instrument sensing line for DEG 2-3.

Section 4OA5 identified a problem identification and resolution crosscutting aspect associated with the corrective actions to ensure measures taken to provide compensatory actions for the removal of the earthquake force monitors were effective and appropriately implemented.

Section 4OA5 identified a problem identification and resolution crosscutting aspect documented in of this report. The issue involves the failure to ensure proper environmental qualification of ASCO solenoid operated valves.

4OA3 Event Followup (71153)

.1 Vital 4kV Bus G De-Energized During Testing

a. Inspection Scope

On November 2, 2004, DEG 2-1 auto-started from a valid 4kV Bus G undervoltage signal. At the time the undervoltage signal was activated, maintenance personnel were in the process of performing a phase sequence verification for DEG 2-1. The inspectors observed operator actions and equipment performance. The inspectors also interviewed operations, engineering, and maintenance personnel. The inspectors reviewed the event for level of investigatory response, corrective actions, violation of requirements, and generic issues.

b. Findings

Introduction. A Green, self-revealing NCV was identified for the failure to set up phase sequence test equipment according to procedure, as required by 10 CFR Part 50, Appendix B, Criterion V. This failure resulted in the momentary de-energization of Vital 4kV Bus G and the auto-start of DEG 2-1.

Description. On November 2, 2004, maintenance personnel were performing Procedure PMT 21.46, “Diesel Generator 2-1 Phase Sequence Verification,” Revision 1, to verify the phase sequence of DEG 2-1. Maintenance personnel connected the test equipment to Vital 4kV Bus G potential transformers and to DEG 2-1 potential transformers. Seconds later, the auxiliary power supply to Vital 4kV Bus G was removed and DEG 2-1 auto-started. Upon investigation, it was found that the test equipment had been wired incorrectly, when compared to the drawing in Procedure PMT 21.46. The drawing had maintenance personnel connect the primary side of the test transformers in a delta configuration. The primary side of the test transformers was denoted ‘X1', ‘X2', and ‘X3'. The drawing had maintenance personnel connect the secondary side of the test transformers in a wye configuration. The secondary side of the test transformers was denoted ‘H1', ‘H2', and ‘H3'. Contrary to the drawing, maintenance personnel connected the primary side of the test transformers in a wye configuration and the secondary side in a delta configuration. The result of wiring the test transformers in this manner and connecting them to the potential transformers was to introduce a direct short to ground on the secondary side of the Vital 4kV Bus G and DEG 2-1 potential transformers. The short was introduced since the secondary side of the potential transformers is an open-delta configuration and the primary side of the test transformers was a wye configuration. The short circuit degraded the voltage on the secondary side of the Vital 4kV Bus G potential transformers, which caused the second level undervoltage relay to perceive an actual degraded voltage on the bus. After second level undervoltage relay timed out, it removed the auxiliary power supply from Vital 4kV Bus G. Since startup power was cleared for maintenance, DEG 2-1 auto-started and loaded onto the bus.

The inspectors observed that safety-related electrical equipment operated as designed when the undervoltage condition was sensed. PG&E acknowledged the maintenance crew that performed the work were PG&E employees. However, the crew worked for the substation-grid maintenance group, which is separate from Diablo Canyon Power Plant. The inspectors also observed that Diablo Canyon Power Plant labels the primary side of its three-phase transformers as ‘X1', ‘X2', and ‘X3' and the secondary side as ‘H1', ‘H2', and ‘H3'. This labeling scheme is the opposite of industry practice, which is to name the primary side as ‘H1', ‘H2', and ‘H3' and the secondary side as ‘X1', ‘X2', and ‘X3'. The substation-grid maintenance crew was accustomed to the industry convention for labeling transformer connections. This finding involved a human performance cross-cutting aspect for the failure to wire the phase sequence test equipment properly for Vital 4kV Bus G and DEG 2-1.

Analysis. The performance deficiency associated with this event is the failure to wire and connect the test equipment according to Procedure PMT 21.46. The finding impacted the Mitigating Systems Cornerstone for ensuring the availability and capability of systems that respond to initiating events to prevent undesirable consequences that was associated with pre-event human error performance. Considering Example 4.b of Inspection Manual Chapter 0612, Appendix E, the finding is greater than minor since the incorrect wiring and connection of the test equipment resulted in a vital bus de-energization and the actuation of DEG 2-1. Using Checklist 4 of Inspection Manual Chapter 0609, Appendix G, Attachment 1, the finding did not result in the Technical Specifications for AC and DC power sources not being met and the finding was determined not to increase the likelihood of a loss of reactor coolant system inventory, degrade PG&E’s ability to terminate a leak path or add reactor coolant system inventory when needed, or degrade PG&E’s ability to recover decay heat removal once it is lost. Therefore, the finding was screened as having very low safety significance

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, PG&E failed to wire and connect the phase sequence test equipment in accordance with Procedure PMT 21.46. The failure to wire and connect the test equipment properly resulted in a momentary de-energization of Vital 4kV Bus G and the auto-start of DEG 2-1. Because the failure to correctly wire and connect the test equipment is of very low safety significance and has been entered into the corrective action system as AR A0622434, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/04-05-09, Failure to Wire and Connect Test Equipment Resulted in Vital Bus De-Energization.

.2 (Closed) Licensee Event Report (LER) 05000323/2003-001-00, Steam Generator Tube Plugging Due to Stress Corrosion Cracking.

On February 13, 2003, with Unit 2 in Mode 6 (Refueling), analysis of eddy current testing on Steam Generator 2-4 indicated that greater than one percent of tubes were defective. The inspectors verified that PG&E complied with Technical Specification 5.5.9 and 5.6.10 and documented the deficiency in the corrective action program. The inspectors also verified that PG&E took appropriate corrective actions and no new findings were identified during the review. This LER is closed.

.3 (Closed) LER 05000323/2003-002-00, Unanalyzed Condition in the Unit 2 Component Cooling Water System

On February 17, 2003, while Unit 2 was de-fueled, PG&E discovered that the liner for Valve CCW-2-18 was damaged such that the valve could not close to provide adequate train separation post-accident.

In NRC Inspection Report 50-275;323/2003-05, a self-revealing Green noncited violation of 10 CFR 50, Appendix B, Criterion XI was identified for this issue. No new information that would change the disposition of this issue was provided in this LER. This LER is closed.

.4 (Closed) LER 05000323/2003-003-00, Technical Specification 3.4.12 Not Met Due to Personnel Error.

On March 9, 2003, while Unit 2 was in Mode 5 (Cold Shutdown), operators placed the power operated relief valve control switches in the "Closed" position vice the required "Auto" position as required by Technical Specification 3.4.12 for low temperature over pressure protection. This condition existed for approximately 23 hours.

In NRC Inspection Report 50-275;323/2003-05, a licensee-identified Green noncited violation of Technical Specification 3.4.12 was documented for this issue. No new information that would change the disposition of this issue was provided in this LER. This LER is closed.

4OA4 Other Crosscutting Aspects of Findings

Section 1R04.1 identified a human performance crosscutting aspect for the labeling error in the core offload planning maps, which subsequently resulted in the core offload sequence being developed in a manner that caused Detector N-52 not to have any adjacent fuel assembly. A second human performance crosscutting aspect was identified for the failure to ascertain the cause of the downward trend when first identified by the inspectors.

Section 1R14.1 identified a human performance crosscutting aspect (resources) for an inadequate alarm procedure.

Section 1R14.2 identified a human performance cross cutting aspect for the failure on two occasions to address configuration control concerns with the spent fuel pool skimmer system.

Section 2OS1 describes two issues with human performance crosscutting aspects which involved personnel entry into a high radiation area with dose rates greater than 1 rem per hour while using the incorrect radiation work permit and the incorrect installation of locking mechanisms for a high radiation area with dose rates greater than 1 rem per hour.

Section 4OA3.1 identified a human performance crosscutting aspect for the failure to wire the phase sequence test equipment properly for Vital 4kV Bus G and DEG 2-1.

Section 4OA5.5 identified a human performance crosscutting aspect associated with compensatory measures to address the removal of the earthquake force monitors.

4OA5 Other

.1 Temporary Instruction 2515/150: Circumferential Cracking of Reactor Pressure Vessel (RPV) Head Penetration Nozzles

a. Inspection Scope

The inspectors observed and reviewed PG&E's activities associated with the RPV head and vessel head penetration nozzle inspection that were implemented in accordance with the requirements of Order EA-03-009.

PG&E performed ultrasonic and eddy-current examinations of all control element drive mechanism penetrations. The inspectors independently reviewed the inspection results for two of the penetrations. PG&E did not identify any nozzle or weld degradation.

PG&E performed a 100 percent visual inspection of the reactor vessel head. The inspectors reviewed a detailed video tape of the head examination. No flaws were identified.

b. Findings

No findings of significance were identified.

.2 Temporary Instruction (TI) 2515/152, "Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02)," Revision 1

Background. The NRC noted in Regulatory Issue Summary 2003-13, "NRC Review of Response to Bulletin 2002-01, " Reactor Pressure Head Degradation and Reactor Coolant Pressure Boundary Integrity, "that most licensee do not perform inspections of Alloy 600/82/182 materials beyond those required by Section XI of the ASME Code to identify potentially cracked and leaking components. For the RPV lower head, the ASME Code specifics that a visual examination be performed during system pressure testing. Licensees may meet the ASME Code requirement by performing an inspection of the RPV lower head without removing insulation from around the head and its penetrations. By performing the visual inspection in this manner, licensees may not be able to detect the amounts of through-wall leakage that would be expected from flaws due to primary water stress corrosion cracking or other potential cracking mechanisms.

Diablo Canyon Power Plant performed a bare metal visual (BMV) examination of the RPV lower head penetrations on October 27-28, 2004. The BMV examination was implemented to verify the absence of boric acid crystals, which may be evidence of a leak in the lower head penetration nozzles.

a. Inspection Scope

During the week of November 29, 2004, the inspectors conducted an evaluation and assessment of the Unit 2 RPV lower head penetration BMV examination performed by PG&E staff according to TI 2515/152. During the inspection, the inspectors performed the following actions:

- A review of PG&E response to NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," to ensure compliance with existing regulations;

- A review of qualifications and certification of inspection personnel, as well as, the quality of techniques and equipment to identify small boric acid deposits;

- A verification that PG&E staff were appropriately following their procedural guidance during the examination;

- An independent review of a sample of lower head penetrations to verify the absence of boric acid deposits that may be indicative or primary stress corrosion cracking around the penetrations;

- A review of how PG&E staff dispositions evidence of boric acid on the RPV lower head;
- A verification of PG&E's ability and performance of a 100 percent visual inspection of the penetrations;
- A review of PG&E's corrective actions with regards to anomalies, deficiencies, and discrepancies associated with reactor coolant system structures or the examination process; and
- Identification of areas on the RPV lower head or lower head penetration nozzles obscured by debris, insulation, dirt, boric acid deposits from pre-existing leaks such as from the reactor cavity seal, coatings, or other obstructions.

The inspectors observed 100 percent of the lower head penetration nozzles using videotapes of the RPV lower head examination.

b. Findings

The inspectors confirmed that PG&E staff inspected 360 degrees of 100 percent of the RPV lower head penetration nozzles. In addition, PG&E performed a thorough inspection of the general condition of the lower head. PG&E staff concluded that none of the RPV lower head penetration nozzles indicated leakage per the BMV examination. The inspectors reviewed staff training, equipment capability, procedures, and the process by which the inspection was performed and found them to be adequate in detecting small boron deposits that would indicate RPV lower head penetration nozzle leakage.

Training and Qualifications

The inspectors reviewed the qualification and certification of the personnel performing the examination. Qualifications for a VT-2 examiner were described in Procedure TQ1.ID12, "Qualification and Certification or NDE Personnel," Revision 2. The inspectors found the procedure requirements to be consistent with industry standards. In addition to training and qualification, each of the examiners had previous experience with BMV examinations for both RPV top head and lower head. The examination experience was gained at the Diablo Canyon Power Plant and other Westinghouse pressurized water reactors. The inspectors reviewed training material for the examiners, which included photos of the RPV lower head penetration nozzle leakage at the South Texas Project Unit 1 and EPRI Technical Report 1007842, "Visual Examination for Leakage of PWR Reactor Head Penetrations."

Procedure ISI X-CRDM, "Reactor Vessel Tap and Bottom Head Visual Inspections," Revision 3, governed the BMV examination of the RPV lower head penetration nozzles. The inspector verified that (1) criteria for the disposition of boric acid indications was appropriate, (2) conduct of the examination was sufficient and according to the procedure, and (3) the procedural guidance satisfied commitments in PG&E's response to NRC Bulletin 2003-02.

Condition of Unit 2 RPV Lower Head

The Unit 2 RPV did not have any active indications of boric acid leakage form any of the penetrations. This determination was made based on a review of the videotaped examination. The inspectors did note boric acid stains which ran down the RPV and down some of the lower head penetrations. The boric acid stains did not have a three-dimensional structure and were determined to have originated from an earlier reactor cavity seal leak. In some instances, the boric acid stains supported very light surface rust, but there was not indication of metal loss. PG&E determined the boric acid stains would not impact the integrity of the RPV lower head, and therefore, no cleaning is planned. The inspectors verified that the boric acid stains would not mask any potential boric acid accumulation that would indicate RPV lower head penetration nozzle leakage. No condition was identified that required repair.

Impediments to Effective Examinations

The inspectors concluded that PG&E examiners encountered no impediments that impacted the examination of the RPV lower head. The examiners performed a 100 percent visual inspection of the RPV lower head.

.3 Temporary Instruction (TI) 2515/153, "Reactor Containment Sump Blockage (NRC Bulletin 2003-001)

a. Inspection Scope

The inspectors reviewed PG&E's response to NRC Bulletin 2003-001. PG&E's response included plant modifications, interim procedure revisions, training, and analysis to verify that the containment sump screens would be operable following the spectrum of design basis accidents. The inspectors verified PG&E's actions in response to NRC Bulletin 2003-001. The inspection consisted of interviews, reviews of training records, containment sump inspections, containment walkdowns, and inspection of the new containment sumps.

PG&E modified the containment sump screens to have greater surface area and to cause the water to change direction to prevent direct impingement of debris on the screens in Refueling Outages 1R12 (Unit 1), and 2R12 (Unit 2). PG&E constructed a partial scale mockup to demonstrate the effectiveness of this new design. The inspectors observed that the mockup of the new screens provided reasonable assurance that the new design would maintain sump operability in the event of debris migration to the containment sump screens postaccident.

The inspectors also verified that the emergency operating procedures were revised to include interim actions to take in the event of screen clogging. The inspectors verified that operators had been trained on this interim guidance.

During outage 2 R12 (Unit 2) on December 3, 2004, the inspectors performed a containment walkdown to ensure that the containment was free debris. In addition, the inspectors entered the containment sump to ensure there were no gaps in the screens and that the sumps were free of debris.

Answers to Interim Questions in TI 2515/153

a. Yes. PG&E conducts containment walkdowns to identify potential debris sources at the end of each refueling outage (including the recently completed outage 2R12).

b. Not applicable.

c. Not applicable.

d. Yes. The walkdowns conducted in Outages 1R12 (Unit 1) and 2R12 (Unit 2) included checks for gaps in the containment sump screens.

e. Yes. Modifications to the containment sump screens are complete.

b. Findings

No findings of significance were identified.

.4 (Closed URI 05000275;323/2003002-01): Licensee Made Changes to the Fire Protection Program That Could Have the Potential to Adversely Affect Their Ability to Achieve and Maintain Safe Shutdown.

a. Inspection Scope

The inspectors identified an unresolved item in which PG&E made changes to the fire protection program that could have the potential to adversely affect their ability to achieve and maintain safe shutdown. In particular, PG&E removed a Thermo-Lag fire barrier, and established manual actions to open component cooling water supply header motor-operated Valve FCV-431 if it spuriously operated as a result of fire damage. This item was made unresolved pending receipt of additional information from PG&E concerning the methodology used for determining that Valve FCV-431 would not sustain damage to the extent that it would not be able to be manually operated.

b. Findings

The inspectors referred this issue to the NRC Office of Nuclear Reactor Regulation (NRR) for review. The NRR staff had discussions with PG&E and reviewed technical information provided by PG&E. The conclusion was that Valve FCV-431 would not be damaged in a stall condition and would remain available to be manually operated. This closes URI 05000275;323/2003002-01.

Whether reliance on the manual use of Valve FCV-431 during a fire event, in lieu of providing protection required by 10 CFR Part 50, Appendix R, Section III.G.2, constitutes a violation of NRC requirements will be addressed in the closure of Unresolved Item 05000275;323/2003002-02.

.5 (Closed URI 05000275;323/2004004-02): Evaluation of Earthquake Force Monitors for EAL [emergency action level] Implementation that were identified in Section 1R14.1 and 1R17 of Inspection Report 05000275;323/2004004 and was the subject of EA 04-0169.

a. Inspection Scope

The inspectors performed additional inspection associated with this unresolved item to determine any performance issues associated with the modification to the earthquake force monitors and the impact on implementing the Diablo Canyon Emergency Plan. This included the adequacy of the earthquake force monitor modification, the associated reviews, impact of work activities prior to and subsequent to August 9, 2004, on the operators' ability to appropriately assess a seismic event per the emergency action levels (EALs) and any reduction in the effectiveness of the emergency plan.

b. Findings

Introduction. The inspectors identified a Green NCV for the failure to establish compensatory measures to ensure the prompt implementation of the Diablo Canyon Emergency Plan as required by 10 CFR 50.54(q) and the risk significant planning standard function,10 CFR 50.47(b)(4) was met.

Description. The inspectors noted that on August 9, 2004, PG&E removed the earthquake force monitor (EFM) from service for surveillance testing on numerous occasions without implementing compensatory actions for the operators to determine the magnitude of a seismic event. The inspectors noted that from 1999-2004 the EFM was inoperable for test and/or calibration 91 times. Most of these instances were of short duration (i.e. up to 2 hours). However, several of these outages were of appreciably longer duration. The longer outages occurred during June 16-19,1999; December 1-4, 2000; April 25-27, 2002; May 25-29, 2002; November 6-8, 2003; and December 30-31, 2003, respectively. In each of these instances, the EFM was unavailable without specifically identifying the compensatory measures to be taken to implement the emergency plan for natural phenomena (earthquake).

Procedure CP M-4, Section 2.2 required operators to determine the magnitude of an earthquake (to classify the event in accordance with the emergency plan and direct personnel actions) using the Earthquake Force Monitor in the control room. When the EFM was removed from service for replacement, operators were not provided with direction or training to implement the emergency plan with respect to assessing the magnitude of a seismic event, without the EFM available. Operators questioned this action, but were not given immediate direction on what instrumentation to use to assess a seismic event. The inspectors questioned the Operations Manager, who stated that "Operators would make a conservative call and declare a Notification of Unusual Event if they felt an earthquake." The inspectors further continued to question PG&E as to how a determination would be made for a significant earthquake (at the level of Site Area Emergency). On August 10, 2004, Operations Management provided "Shift Orders" to use one seismic monitor (ESTA-05, part of the backup system) that was already installed, to determine the magnitude of an earthquake for classification purposes. Procedure CP M-4 was revised on August 24, 2004, to provide the means of assessing the magnitude of an earthquake.

Prior to August 10, 2004, PG&E had not identified the compensatory measures or alternate seismic instrumentation that would be utilized to implement a significant requirement of the emergency plan, i.e., to classify a seismic event at the level of a NOUE (0.01 g as indicated on the EFM), an Alert (0.2 g as indicated on the seismic monitors) or a Site Area Emergency (0.4 g's as indicated on the seismic monitors). Only the NOUE criteria specifies the EFM as the means of validating the magnitude of a seismic event.

PG&E's basis for emergency action levels is NUREG-0654, Revision 1, Appendix 1. The emergency action levels affected by lack of seismic instrumentation were Table 4.1-1, Diablo Canyon Emergency Plan, Revision 4.03:

- Natural Phenomena (All Modes), VIII (18), Unusual Event, "Ground motion felt and recognized as an earthquake by a consensus of Control Room operators on duty AND measuring greater than 0.01g on the Earthquake Force Monitor"

- Natural Phenomena (All Modes), VIII (17), Alert, "Earthquake > 0.2g verified by Seismic Monitors"

- Natural Phenomena (All Modes), VIII (9), Site Area Emergency, "Earthquake > 0.4g verified by Seismic Monitors"

In assessing PG&E's initial corrective actions, the inspectors questioned PG&E as to the basis of the assigned significance of the action request to ensure that this deficiency received sufficient management attention, and to verify that the immediate corrective actions were effective. Following the identification of the concern on August 9, 2004, PG&E upgraded the deficiency from an action request (lowest tier of significance) to a nonconformance report (highest tier of significance) on August 28, 2004.

Other seismic monitors available during these periods would have required a trained technician onsite to access the data or a coordinated effort with PG&E's offsite geosciences group to assess the weak motion sensors located in the vicinity of Diablo Canyon. These monitors and/or recorders were the Kinemetrics Free Field (ESTA27), the former Engdhal acceleration and shock recorders, the Temp System installed for the inoperable Terra Tech system and the Geoscience weak motion sensors. The reactor seismic trip instrumentation was operable throughout each of these periods.

On August 9, 2004, the EFMs were removed from service to replace the Basic System EFM with the new Syscom system. This same day operators raised concerns with how they were to assess the magnitude of a seismic event during the period the seismic instrumentation was unavailable. PG&E has provided additional information and confirmed by the inspectors that establishes the initial duration as 2 days with a second 2 day period when the shift order referenced instrument was taken out of service. For the first two day period other instruments could have been accessed within a half hour to 3 hour period based on PG&E's assessment of the time required to call in a trained technician if required (dependent on whether the trained technicians were on shift). The inspectors determined that this time period could be met, however, the time involved could be appreciably longer for large magnitude earthquakes that could present physical limitations of an individual's ability to respond from road closures, etc. The NRC staff has determined that at all times seismic instruments would be available to determine the magnitude of a seismic event; however, delays could occur and these delays could impact PG&E's ability to timely assess the magnitude of an earthquake in order to implement its emergency plan for Natural Phenomena.

The inspectors determined that there were other periods when the EFMs had been taken out of service for surveillance testing without compensatory actions being identified for assessing the magnitude of an earthquake. On June 16-19,1999, December 1-4, 2000, April 25-27, 2002, May 25-29, 2002, November 6-8, 2003, December 30-31, 2003, August 9-10, 2004, and other lesser periods, PG&E failed to establish compensatory measures to determine earthquake ground accelerations which are used as entry conditions.

Analysis. The finding did not rise to a failure or degradation of the risk significant planning standard function as other seismic instrumentations were available for the periods identified that would permit PG&E's classification process to make an appropriate classification, although the classification could be substantially delayed beyond a 15 minute period. Other EALs have been established that would cause the Notification of Unusual Event (NOUE), Alert and Site Emergency Classification to be declared (IV. Loss of Control or Release of Radioactive Material and VI. Loss of Engineered Safety Feature) if a release were to occur or damage to the plant following a seismic event. Only the NOUE EAL specifies the use of the EFMs for classifying the event.

Failure to provide compensatory actions for the timely implementation of the Diablo Canyon Emergency Plan, Revision 4.03, for Natural Phenomena (All Modes) is a performance deficiency because PG&E did not meet an RSPS function to ensure the emergency classification and action levels for natural phenomena is in use. It is more than minor because it has a potential to impact safety and because it was not a record keeping or administrative issue or an insignificant procedural error. This deficiency could have affected the Emergency Preparedness Cornerstone objective of ensuring the capability to implement measures to protect the health and safety of the public during an emergency, and is associated with attributes of facilities and equipment, and offsite emergency preparedness. Utilizing the Failure to Comply Flow Chart in Manual Chapter 0609, the performance deficiency does not result in a failure of the RSPS or a degraded RSPS in that the unavailability of the seismic monitors would not prevent (but could delay) the declaration of a Site Area Emergency, Alert or NOUE and results in a Green finding. A seismic event is a self-revealing event that would cause the operators to immediately initiate actions to assess the event. Other EALs were not impeded that would result in EAL classifications up to and including the Site Area Emergency if complications from a seismic event occurred. This finding has problem identification and resolution aspects in that PG&E had opportunities to identify the emergency plan impact prior to removing seismic instrumentation from service, followed by poor recognition of the significance of the issue, and ineffective initial corrective action.

Enforcement. This finding is a violation of 10 CFR 50.54(q) which requires in part that a licensee follow and maintain in effect emergency plans. Specifically, Diablo Canyon Emergency Plan, Revision 4.03, specifies emergency action thresholds in Table 4.1-1 for a NOUE, an Alert, and a Site Area Emergency based on seismic activity. The finding is associated with a risk significant planning standard function,10 CFR 50.47(b)(4), in that a standard scheme of emergency classification and actions levels is in use. Because PG&E's failure to establish compensatory measures to ensure the prompt implementation of the Diablo Canyon Emergency Plan is of very low safety significance and has been entered into the corrective action system as AR XXXXXXX, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275; 323/2004-005-10, Failure to Establish Compensatory Measures to Ensure the Prompt Implementation of the Diablo Canyon Emergency Plan.

.6 (Closed) AV 05000275/2004006-01; 05000323/2004006-01: Noncompliance of Solenoid Operated valves with 10 CFR 50.49 requirements.

Introduction. A self-revealing violation of 10 CFR 50.49(f) was identified for the failure to maintain approximately 70 safety related solenoid operated valves in an environmentally qualified condition. On February 9, 2002, an age related ASCO solenoid operated valve coil failed and caused a loss of Steam Generator feed event and a Unit 2 manual plant trip. Further, PG&E did not promptly evaluate the extent of condition of the ASCO failure, which delayed the identification of elastomer qualification issues for approximately 1 year. In a related finding, the team identified that PG&E had missed earlier opportunities to identify ASCO elastomer qualification issues, in that they failed to thoroughly evaluate several pertinent NRC information notices and previous valve failures. The failure to: 1) properly establish equipment qualification limits; 2) thoroughly evaluate plant events and failures; and 3) properly evaluate industry operating experience constituted performance concerns. These issues have crosscutting aspects in the area of problem identification and resolution.

Description. On February 9, 2002, operators manually tripped Unit 2 due to lowering Steam Generator 2-4 water level. An ASCO solenoid operated valve had failed, causing Main Feedwater Regulating Valve FW-2-FCV-540 to close. PG&E determined the failure was due to thermal aging degradation of the coil wire insulation. PG&E found that inappropriate criteria were used in determining the acceptable qualified life of the solenoid coils.

The team identified that PG&E did not promptly perform an extent of condition evaluation, which delayed the identification that qualification life for ASCO valve elastomers was also miscalculated. Approximately a year after the plant trip, PG&E

recognized the error. The elastomer limitations were slightly more restrictive than those of the coil. These discrepancies resulted in the qualified life of the solenoid operated valves being corrected from approximately 22 years to 7 years. Overall, approximately 70 valves were affected in both units.

In a related concern, the team identified that PG&E failed to effectively utilize industry operating experience that discussed the failure of ASCO solenoids due to degraded elastomers. This information was provided to the industry in NRC Information Notices 88-43, “Solenoid Valve Problems;” 89-66, “Qualification Life of Solenoid Valves;” 85-17, “Possible Sticking of ASCO Solenoid Valves;” 86-57, “Operating Problems with Solenoid Operated Valves at Nuclear Power Plants;” and 84-23, “Results of the NRC-Sponsored Qualification Methodology Research Test on ASCO Solenoid Valves.” The team reviewed PG&E’s responses to these notices and determined that in general PG&E’s responses were narrowly focused. For example, PG&E determined that a solenoid problem would not be seen at their facility because they were not using the same model number that was being discussed in the notice, even though the issue concerned the potential for general elastomer material degradation due to elevated temperatures. The team also noted that PG&E had experienced prior failures of ASCO solenoid operated valves due to sticking or binding conditions.

This finding involved crosscutting aspects in the area of problem identification and resolution because the original corrective actions did not identify the full scope of the cause and extent of condition, delaying corrective actions for approximately 1 year. In addition, PG&E did not properly address generic industry information concerning ASCO elastomers.

<u>Analysis</u>. This finding was greater than minor because, if left uncorrected, these deficiencies would become a more significant safety concern by increasing the failure rate as the components age. This finding potentially affected the Initiating Events, Mitigating Systems, and Barrier Integrity Cornerstone objectives.

An NRC Senior Reactor Analysts performed a Phase 3 significance determination. The following assumptions were utilized:

- Based on a historical data review performed by PG&E at the request of the Senior Reactor Analyst, the following failure rates were determined for solenoid valves that had exceeded their EQ replacement frequencies:

  Demand failures = 2.1E-3 / demand

  This applies to a situation where the valve is called upon to change state, but fails to do so

  Failure rate = 3.19E-7/hr.

  This applies to a situation where the valve unintendedly changes state because of a failure of the solenoid valve related to the EQ issue.

The above failure information applies only to valve failures that occurred in a manner such that the failure could be attributed to the aging effects related to EQ. Failures for other causes were not included in the analysis. The period of the review was 1998 to the present.

- The individual effect of a short-term harsh environment on an over-aged solenoid valve is considered to be negligible because the finding contributed to a long-term aging mechanism and not a short-term temperature, water, radiation, or humidity intrusion effect. Therefore, the over-aged valves are considered to perform equivalently to the in-specification valves during an accident scenario.

The estimated delta-CDF for the finding is 2.2E-8/yr. Therefore, the violation was of very low risk significance (Green).

Enforcement. Section (a) of 10 CFR 50.49(f) requires, in part, that each item of electric equipment important to safety to be environmentally qualified. Contrary to the above, PG&E did not maintain environmental qualification for a total of approximately 70 ASCO solenoid operated valves in Units 1 and 2. The failure to maintain the environmental qualification was a violation of 10 CFR 50.49(f). Because the violation was of very low safety significance, and was entered into PG&E's corrective action program (Action Request A0613008), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000275; 323/2004005-11).

40A6 Management Meetings

Exit Meeting Summary

The inspectors presented the emergency preparedness exercise inspection results to Mr. Jim Becker, Station Director, and other management and staff members at the conclusion of the inspection on December 10, 2004. PG&E acknowledged the findings presented. The inspector verified no proprietary information was discussed during the inspection.

The resident inspection results were presented on January 6, 2005, to Mr. David Oatley, Vice President and General Manager, Diablo Canyon, and other members of PG&E management. PG&E acknowledged the findings presented.

The inspectors asked PG&E whether any materials examined during the inspection should be considered proprietary. Proprietary information was not reviewed by the inspectors.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by PG&E and is a violation of NRC requirements, which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a NCV.

Technical Specification 5.4.1.a requires procedures to be established, implemented and maintained covering the activities described in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Appendix A of Regulatory Guide 1.33, requires procedures for the residual heat removal (RHR) system. Final Safety Analysis Report Section 5.5.6 states that, to maintain the ability to open the RHR suction valves (Valves RHR-2-8701 and -8702) from the control room when the solid state protection system (SSPS) is de-energized, a jumper is installed to bypass the SSPS interlocks. Contrary to the above, procedures for the RHR system were not adequately maintained. Specifically, as of November 1, 2004, the jumper to bypass the interlocks had not been installed, following and during Unit 2 mid-loop operations. PG&E procedures for operation of the RHR system, or control of outage activities, did not direct installation of this jumper. Procedure STP I-38-AB.1 "SSPS Train A&B Removal from Service for Testing/Maintenance in Modes 5 or 6," Revision 1, required the jumper to be installed to maintain the ability to open the RHR suction valves only if the SSPS system was de-energized by removing fuses. The SSPS system was removed from service by opening the supply breaker. This finding is more than minor because the condition existed while Unit 2 was in mid-loop operations, and would have impeded recovery from a loss of RHR, if the RHR suction valves were closed. This finding is of very low safety significance because the ability to locally open the valves using the handwheel was maintained. In addition, the RHR system continued to operate properly during midloop operations and was not challenged. Therefore, this issue screens as Green. This finding is entered into PG&E’s corrective action program as Action Request A0622371.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

PG&E personnel

J. Becker, Vice President - Diablo Canyon Operations and Station Director
C. Belmont, Director, Nuclear Quality, Analysis, and Licensing
S. Chesnut, Director, Engineering Services
J. Fledderman, Acting Director, Maintenance Services
S. Ketelsen, Manager, Regulatory 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

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

50-323/2004-05-01	NCV	Mislabel of Neutron Flux Detector Resulted in Neutronic Decoupling of Detector From the Core (Section 1R04.1)
50-275; 323/2004-05-02	NCV	Failure to Promptly Correct Containment Fan Cooler Unit Reverse Rotation (Section 1R04.2)
50-323/2004-05-04	NCV	Failure to Properly Implement Procedure for Spent Fuel Pool Skimmer Filter Replacement (Section 1R14.2)
50-275/2004-05-05	NCV	Failure to Adequately Correct ECCS Voiding Following Operation of the Positive Displacement Pump (Section 1R15)
50-323/2004-05-07	NCV	Failure to Lock a High Radiation Area with Dose Rates Greater than 1 Rem per Hour Area with Dose Rates Greater than 1 Rem per Hour (Section 2OS1)
50-323/2004-05-08	NCV	Failure to Access a High Radiation Area with Dose Rates Greater than 1 Rem per Hour with the Correct Radiation Work Permit (Section 2OS1)
50-323/2004-05-09	NCV	Failure to Wire and Connect Test Equipment Resulted in Vital Bus De-Energization (Section 4OA3.1)
50-275; 323/2004-05-10	NCV	Failure to Establish Compensatory Measures to Ensure the Implementation of the Diablo Canyon Emergency Plan as Required by 10 CFR 50.54(q) and the Risk Significant Planning Standard Function,10 CFR 50.47(b)(4) (Section 4OA5.5)

50-275; 323/2004-05-11	NCV	Inadequate ASCO valve qualification causes plant trip (Section 4A05)

Open

50-323/2004-05-03	URI	Adequately of Alarm Procedure For Feedwater Heater Level Control Malfunctions.(Section 1R14.1)
50-323/2004-05-06	URI	Failure to Promptly Correct Diesel Engine Generator Lube Oil Instrument Line Crack (Section 1R15)

Closed

50-323/2003-001-00	LER	Steam Generator Tube Plugging Due to Stress Corrosion Cracking (Section 4OA3.2)
50-323/2003-002-00	LER	Unanalyzed Condition In the Unit 2 Component Cooling Water System (Section 4OA3.3)
50-323/2003-003-00	LER	Technical Specification 3.4.12 Not Met Due to Personnel Error (Section 4OA3.4)
50-275; 323/2003-002-01	URI	Licensee Made Changes to the Fire Protection Program That Could Have the Potential to Adversely Affect Their Ability to Achieve and Maintain Safe Shutdown (Section 4OA5.4)
50-275; 323/2004-004-02	URI	Evaluation of Earthquake Force Monitors for EAL Implementation that were identified in Section 1R14.1 and 1R17 and was the subject of EA 04-0169 (Section 4OA5.5)
05000275/2004006-01 05000323/2004006-01	APV	Inadequate ASCO valve qualification causes plant trip (Section 4A05)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Action Requests

A0224682	A0533621	A0589415
A0326457	A0539622	A0595426
A0412679	A0542698	A0602491
A0478486	A0557943	A0610960
A0479124	A0568655	A0613036

A0492190	A0574615	A0619139
A0518387	A0587895	A0619185

Calculations

PET-92-119, “RCFC Reverse Speed vs. Torque,” Revision 0
PCE-92-0044, “PGE - RCFC Reverse Speed vs. Torque,” Revision 0

Section 1R08: Inservice Inspection Activities

Procedures

ISI-VT-2-1, “Visual Examination During Section XI System Pressure Test,” Revision 6,

NDE-N-UT-4, “Ultrasonic Examination of Pressure Vessel Welds Other Than Reactor Vessels,” Revision 9

NDE-PDI-UT-2, “Ultrasonic Examination of Austenitic Piping,” Revision 3A

STP-R-8C, “Containment Walkdown for Evidence of Boric Acid Leakage,” Revision 8A

Miscellaneous Documents

“Steam Generator Tubing Degradation Assessment, Diablo Canyon Unit 2, Refueling Outage 2R12,” Revision 0

Ultrasonic Examinations

WIB-248
WIB-358-1
WIB-358-2
WIB-393
WIB-394

Action Requests

A0574355	A0606347	A0623246
A0574572	A0608944	A0595426
A0574893	A0618807	A0623417
A0576197	A0622851	A0623440
A0577052	A0622911	A0623471
A0584122	A0622916	A0623473
A0606013	A0623160	

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures

OP J-6B:III, “Diesel Generator 1-3 Make Available,” Revision 22

Other

Clearance 79266
Risk Assessment RA02-05, Revision 2

Section 1R15: Operability Evaluations

Action Requests

A0584039 A0624988 A0625020

Procedures

OP J-2:VIII, “Guidelines for Reliable Transmission Service for DCPP,” Revision 5

Section 1R19: Postmaintenance Testing

Action Requests

A0627391

Work Orders

R0243795

Section 1R22: Surveillance Test

Action Requests

A0622185 A0622199 A0623371

1EP1 Exercise Evaluation (71114.01)

Emergency Plan Implementing Procedures (EPIPs)

EP G-1, “Emergency Classification and Emergency Plan Activation,” Revision 33B
EP G-2, “Interim Emergency Response Organization,” Revision 30
EP G-3, “Emergency Notification of Off-site Agencies,” Revision 42
EP RB-8 “Instructions for Field Monitoring Teams,” Revision 18
EP RB-9, “Calculation of Release Rate,” Revision 11A
EP RB-10, “Protective Action Recommendations,” Revision 11
EP RB-11, “Emergency Offsite Dose Calculations,” Revision 12
EP EF-1, “Activation and Operation of the Technical Support Center,” Revision 32
EP EF-2, “Activation and Operation of the Operational Support Center,” Revision 28
EP EF-3, “Activation and Operation of the Emergency Operations Facility,” Revision 26

EP EF-10, “Activation and Operation of the Joint Media Center,” Revision 7

Administrative Procedure OM10.ID4, “Emergency Response Organization Management,” Revision 5

Section 2OS1: Access Controls to Radiologically Significant Areas

Action Requests

573555, 574447, 575297, 576284, 578891, 579124, 579474, 579616, 579880, 581129, 581131, 581675, 603992, 604397, 604648, 604958, 605030, 605695, 609454, 610681, 615721, 619134, 621210, 621924, 622297, 622516, 622930, and 623133

Audits and Assessments

2003 DCPP Radiation Protection Program Audit

Assessment Number 030410010, 2R11 Radiation Protection Assessment Report - Outage Coverage

Assessment Number 031780001, Radiological Risk Assessment Process for 2R11

Assessment Number 040630025, 1R12 Radiation Protection Assessment Report - Outage Coverage

Quality Performance Assessment Report, Fourth Period 2002 and First Period 2003

Quality Performance Assessment Report, Second, Third and Fourth Periods 2003

Quality Performance Assessment Report, First Period 2004

Quality Verification Assessment of 1R12 Performance Windows 1, 2, and 3

Radiation Work Permits (RWP)

RWP04-0004, RWP04-0011, RWP04-1004, and RWP04-2007

Procedures

DCPP Standard Radiation Practices Manual, Revision 4

RCP D-200 Writing Radiation Work Permits, Revision 30

RCP D-211 Use of Remote Monitoring Technology for Radiation Protection, Revision 0

RCP D-215 Radiological Coverage of Underwater Work, Revision 5

RCP D-220 Control of Access to High, Locked High, and Very High Radiation Areas, Revision 27

RCP D-222 Radiation Protection Lock and Key Control, Revision 3

RCP D-240	Radiological Posting, Revision 16
RCP D-250	Radiological Occurrence Reports, Revision 10A
RCP D-330	Personnel Dosimetry Evaluations, Revision 6
RCP D-420	Sampling and Measurement of Airborne Radioactivity, Revision 18A
RCP D-600	Personnel Decontamination and Evaluation, Revision 21
RCP D-610	Control of Radioactive Materials, Revision 11
RP1.ID7	Control of Radiography, Revision 4
RP1.ID9	Radiation Work Permits, Revision 7

Miscellaneous

Committed Effective Dose Equivalent Calculations and whole body counts for one individual
Selected Radiologically Control Access exit dose transactions during the inspection period

Section 4OA1: Performance Indicator Verification

Action Requests

578891, 579124, 581129, 581131, and 605030

Procedures

AWP O-002, NRC Performance Indicators: RETS/ODCM Radiological Effluent Occurrences, Revision 2

AWP O-003, NRC Performance Indicators: Occupational exposure Control Effectiveness, Revision 2

RCP D-250, Radiological Occurrence Reports, Revision 10A

XI1.DC1, Collection and Submittal of NRC Performance Indicators, Revision 4

AWP EP-001, Emergency Preparedness Performance Indicators, Revision 4

OM10.ID1, “Maintaining Emergency Preparedness,” Revision 4

OM10.DC1, “Emergency Preparedness Drills and Exercises,” Revision 2A

Emergency Preparedness Training, “Program of Instruction,” Revision 10

Audits

2003 Annual Radioactive Effluent Release Report
2003 Annual Radiological Environmental Operating Report
Quality Verification Audit 041820006, 2004 Radiological Environmental Monitoring Program (REMP) Audit

Drill, Exercise, and Actual Event Reports

October 23, 2002 Bravo Team Exercise
October 18, 2003 Notice of Unusual Event
October 29, 2003 Bravo Team Exercise
December 22, 2003 Notice of Unusual Event
September 22, 2004 Alpha Team Exercise
September 28, 2004 Notice of Unusual Event

Section 4OA2: Problem Identification and Resolution

Audits

Second Period 2004 (June 1 to October 24) Quality Performance Assessment Report (QPAR)
2004 DCPP Emergency Preparedness Program 50.54(t) Review
Operations Activities Audit 040690003

4OA2 Problem Identification and Resolution

Emergency Planning Guideline EP-G01, “Problem Identification,” May 17, 2002
Self-Assessment of Emergency Action and Classification Levels, EPSA 2004-01
Self-Assessment, Alpha Team Evaluated Exercise December 8, 2004
Self-Assessment, Bravo Team Full-Scale Drill, October 29, 2003

LIST OF ACRONYMS

ADAMS	agency document and management system
ALARA	as low as reasonably achievable
AR	action request
ASME	American Society of Mechanical Engineers
BMV	bare metal visual
CCP	Centrifugal Charging Pump
CCW	component cooling water
CFCU	containment fan cooler unit
CFR	Code of Federal Regulations
ECCS	Emergency Core Cooling System
EPRI	Electric Power Research Institute
FSAR	Final Safety Analysis Report
LER	Licensee Event Report
NCV	noncited violation
NDE	nondestructive examination
NEI	Nuclear Energy Institute
PARS	Publicly Available Records System
PDP	positive displacement pump
PG&E	Pacific Gas and Electric Company
PWR	pressurized water reactor
RHR	residual heat removal
RPV	reactor pressure vessel
RWP	radiation work permit
SDP	Significance Determination Process
SFM	shift foreman
SIP	safety injection pump
SSPS	solid state protection system
TI	Temporary Instruction