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

January 30, 2004

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

SUBJECT: DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000275/2003008 AND 05000323/2003008

Dear Mr. Rueger:

On December 31, 2003, the U.S. Nuclear Regulatory Commission completed an inspection at your Diablo Canyon Power Plant, Units 1 and 2, facility. The enclosed integrated report documents the inspection findings that were discussed on January 8, 2004, with Mr. David H. Oatley and members of your staff.

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

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

During the period of December 22, 2003, through January 9, 2004, the NRC has been conducting event followup inspections at the Diablo Canyon Nuclear Plant in direct response to the December 22, 2003, San Simeon earthquake. These event followup inspections continue. The results of the inspections conducted through December 31, 2003, (referred to as Phase 1 of the event followup inspections) are documented in the enclosed inspection report (see Section 1R14). The results of the inspection conducted January 1-9, 2004, (referred to as Phase 2 of the event followup inspections) and additional onsite inspections planned through

Unit 1 refueling outage, scheduled to begin in March 2004, (referred to as Phase 3 of the event followup inspections) will be documented in NRC Inspection Report 05000275;323/2004002, to be issued approximately at the end of April 2004.

On January 16, 2004, we provided you with some preliminary results of the NRC's event followup for the December 22, 2003, San Simeon earthquake. (ADAMS Accession ML040160653). That letter provided the preliminary results of the inspection activities (Phases 1 and 2) conducted through January 9, 2004, and provided the scope for Phase 3 of the NRC's actions that are ongoing. The Phase 3 activities will involve additional planned inspections, including the visual inspections in Unit 1 containment during the March 2004 refueling outage and further review of your Special Report, submitted to the NRC on January 5, 2004, and any supplemental report.

We plan to conduct a technical meeting with you on February 4, 2004, regarding your January 5, 2004, Special Report in San Luis Obispo, California. This meeting will be open to public observation and will provide attending members of the public a period for comments and questions prior to the conclusion of the meeting.

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

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (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 05000275/2003008
and 05000323/2003008
w/attachment: Supplemental Information

cc w/enclosure:
David H. Oatley, Vice President
and General Manager
Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, CA 93424

Lawrence F. Womack, Vice President, Power
Generation & Nuclear Services
Diablo Canyon Power Plant
P.O. Box 56
Avila Beach, CA 93424

James R. Becker, Vice President
Diablo Canyon Operations and
Station Director, Pacific Gas and
Electric Company
Diablo Canyon Power Plant
P.O. Box 3
Avila Beach, CA 93424

Sierra Club California
2650 Maple Avenue
Morro Bay, CA 93442

Nancy Culver
San Luis Obispo Mothers for Peace
P.O. Box 164
Pismo Beach, CA 93448

Chairman
San Luis Obispo County Board of
Supervisors
Room 370
County Government Center
San Luis Obispo, CA 93408

Truman Burns\Robert Kinosian
California Public Utilities Commission
505 Van Ness Ave., Rm. 4102
San Francisco, CA 94102-3298

Diablo Canyon Independent Safety Committee
Robert R. Wellington, Esq.
Legal Counsel
857 Cass Street, Suite D
Monterey, CA 93940

Ed Bailey, Radiation Control Program Director
Radiologic Health Branch
State Department of Health Services
P.O. Box 942732 (MS 178)
Sacramento, CA 94234-7320

Richard F. Locke, Esq.
Pacific Gas and Electric Company
P.O. Box 7442
San Francisco, CA 94120

City Editor
The Tribune
3825 South Higuera Street
P.O. Box 112
San Luis Obispo, CA 93406-0112

James D. Boyd, Commissioner
California Energy Commission
1516 Ninth Street (MS 34)
Sacramento, CA 95814

Chief, Technological Services Branch
FEMA Region IX
1111 Broadway, Suite 1200
Oakland, CA 94607-4052

Electronic distribution by RIV:
Regional Administrator **(BSM1)**
DRP Director **(ATH)**
DRS Director **(DDC)**
Senior Resident Inspector **(DLP)**
Branch Chief, DRP/E **(WBJ)**
Senior Project Engineer, DRP/E **(VGG)**
Staff Chief, DRP/TSS **(PHH)**
RITS Coordinator **(NBH)**
Anne Boland, OEDO RIV Coordinator **(ATB)**
DC Site Secretary **(AWC1)**
Dale Thatcher **(DFT)**
W. A. Maier, RSLO **(WAM)**

ADAMS: ■ Yes ☐ No Initials: ___WBJ___
■ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ■ Non-Sensitive

R:_DC\2003\DC2003-08RP-DLP.wpd

RIV:RI:DRP/E	SRI:DRP/E	TL:DRS/EMB	C:DRS/PSB	C:DRP/E
TWJackson	DLProulx	RLNease	TWPruett	WBJones
E	***E***	***/RA/***	***/RA/***	***/RA/***
1/28/04	1/28/04	1/27/04	1/26/04	1/28/04

D:DRP	DRA	RA	C:DRP/E (for Signature)
ATHowell For	TPGwynn	BSMallett For	WBJones
MASatorius	**/RA/**	**TPGwynn**	**/RA/**
1/28 /04	1 /30/04	1/30/04	1/30/04

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-275, 50-323
Licenses:	DPR-80, DPR-82
Report:	05000275/2003008 05000323/2003008
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:	September 28 through December 31, 2003
Inspectors:	D. L. Proulx, Senior Resident Inspector T. W. Jackson, Resident Inspector S. M. Wong, Risk Analyst R. E. Lantz, Senior Emergency Preparedness Inspector M. P. Shannon, Senior Health Physicist B. Tharakan, Health Physicist
Approved By:	W. B. Jones, Chief, Project Branch E Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000275/2003-008, 05000323/2003-008; 09/28/03 - 12/31/03; Diablo Canyon Power Plant Units 1 and 2; Fire Protection, Maintenance Effectiveness, Postmaintenance Testing, ALARA Planning and Controls, Problem Identification and Resolution.

This report covered a 14-week period of inspection by resident inspectors and announced inspections in emergency preparedness and radiation protection and followup inspections to the October 18 and December 22, 2003, earthquakes. Specifically, Section 1R14.1 documents the followup inspections performed in response to earthquakes impacting the Diablo Canyon Power Plant. The NRC identified four Green noncited violations and one Green finding. 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. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a violation of Technical Specification 5.4.1.d which requires written procedures be established, implemented, and maintained covering the Fire Protection Program implementation. Specifically, PG&E failed to adequately establish and implement procedural changes that provided for senior control operators, licensed control operators, and nonlicensed, Level 8 nuclear operators to serve in the operator responder position. The inspectors noted that the applicable attachment to the procedure for conduct of the operations response position was not established until after training had been provided on implementing the procedure. Operations' responders supporting the fire brigades exhibited a knowledge weakness in activities such as communications with the control room, manual actuation of fire suppression equipment, and providing information to the fire brigade regarding safe shutdown equipment.

  The finding impacted the procedure quality objective under the mitigating systems cornerstone and was more than minor since there was an adverse impact to a fire protection defense-in-depth element. Using the Significance Determination Process (SDP) Phase I Screening Worksheet and the SDP Phase II Notebook in Appendix F of Inspection Manual Chapter (IMC) 0609, the inspectors determined that the finding was of very low safety significance. Specifically, the significance of the finding was evaluated by considering fire scenarios in the vital 4 kV Bus F switchgear room and auxiliary saltwater Pump 1-1 vault. These two areas have the highest dependence on fire brigade response since they have the highest fire ignition frequency for areas that do not have automatic fire suppression. The inspectors evaluated the risk-significance using half of the nominal credit for manual fire suppression as a result of the finding. Using Tables 5.4, 5.5, and 5.6 of IMC 0609, both fire scenarios screened as very low safety significance. Since the two fire scenarios were considered worst-case for the finding, the inspectors determined that the finding was of very low safety significance (Section 1R05.2).

- Green. The inspectors identified a noncited violation for the failure to adequately monitor the performance of the Unit 1 auxiliary feedwater system in accordance with 10 CFR 50.65(a)(2). Specifically, the unavailability time performance criteria for the auxiliary feedwater system had been exceeded during its monitoring period, but the system was not monitored per 10 CFR 50.65(a)(1).

  The finding impacted the mitigating systems cornerstone objective to ensure the availability and reliability of the auxiliary feedwater system to respond to initiating events. The finding is greater than minor using Example 1.f of Inspection Manual Chapter 0612, Appendix E. Similar to the example, the inspectors identified that Pacific Gas and Electric did not consider unavailability time for the Unit 1 auxiliary feedwater system, although the unavailability time was due to prior poor maintenance practices on Valve FW-1-FCV-437. If the unavailability time was considered, the 10 CFR 50.65(a)(2) evaluation would be invalid. Using the Significance Determination Process Phase I worksheet in Inspection Manual Chapter 0609, Appendix A, the finding is of very low safety significance, since there was no loss of an actual safety function, no loss of a safety-related train for greater than the Technical Specification allowed outage time, and the finding is not potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event (Section 1R12).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion III, when Pacific Gas and Electric personnel failed to adequately evaluate the capability of core exit thermocouples to measure the radial temperature gradient for Quadrant 1 of the Unit 1 reactor core. Specifically, maintenance personnel inadvertently swapped core exit thermocouples at a connection, leaving only three operable thermocouples per Trains A and B for Quadrant 1. When questioned by the inspectors, engineering personnel could not provide an adequate technical bases for how measurement of radial temperature gradient could be accomplished.

  The finding impacts the mitigating system cornerstone through degraded overall availability of the components within a system used to assess and respond to initiating events to prevent undesirable consequences. The finding was greater than minor when compared to Example 3.a of Inspection Manual Chapter 0612, Appendix E. Similar to Example 3.a, Pacific Gas and Electric performed additional work to verify the ability of the core exit thermocouples to measure radial temperature gradient within Quadrant 1 of the Unit 1 reactor core. Using the Significance Determination Process Phase 1 screening worksheet from Inspection Manual Chapter 0609, Appendix A, the finding was determined to be of very low safety significance, since the deficiency was confirmed not to result in loss of function per Generic Letter 91-18, Revision 1 (Section 1R19).

- Green. A self-revealing violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for failure to promptly identify and correct a condition adverse to quality. Specifically, in December 2000, Pacific Gas and Electric failed to identify and correct the population of Rockwell-Edwards valves in safety-related and risk-significant systems that were susceptible to failure of the packing gland follower flange from intergranular stress corrosion cracking. Pacific Gas and Electric received an industry notification in December 2000 that Rockwell-Edwards valves were vulnerable for this type of failure, but initiated corrective actions on a very limited population of valves (those involving a trip risk). As a result, on December 3, 2003, the packing gland follower flange for safety injection Valve SI-1-8890A (pressure equalization valve) on the hot leg injection line failed, due to intergranular stress corrosion cracking, resulting in excessive packing gland leakage.

  The finding impacted the mitigating systems cornerstone through degraded equipment performance for a system train that responds to initiating events to prevent undesirable consequences. The finding is greater than minor because the finding would become a more significant safety concern if the valve condition was left uncorrected. The amount of leakage from the valve would be significantly greater than a 30 drop per minute leak rate, if the safety injection pumps were fully running in the hot leg injection mode. The Valve SI-1-8890A leak rate is bounded by a residual heat removal pump seal failure. Pacific Gas and Electric concluded the safety injection system was operable but degraded because both safety injection system trains would be available to provide adequate flow if a demand occurs. Using the Significance Determination Process Phase 1 worksheet in Inspection Manual Chapter 0609, Appendix A, the finding was determined to be of very low safety significance, since there is no loss of an actual safety function, no loss of a safety-related train for greater than the Technical Specification allowed outage time, and the finding is not potentially risk significant due to a seismic, fire flooding, or severe weather initiating event (Section 4OS2.2)

Cornerstone: Occupational Radiation Safety

- Green. A finding was identified because Pacific Gas and Electric failed to maintain collective doses as low as is reasonably achievable. Specifically, work activities associated with Radiation Work Permit 03-2055, "Reactor Coolant Pump (RCP) 2-2, 10 year inspection," exceeded 5 person-rem and the dose estimation by more than 50 percent due to a miscommunication among work groups.

  The failure to maintain collective doses as low as is reasonably achievable is a performance deficiency. This finding was more than minor because it is associated with the Occupational Radiation Safety Cornerstone attribute (program and process) and affected the associated cornerstone objective (to ensure adequate protection of workers’ health and safety from exposure to radiation). This occurrence involved inadequate planning which resulted in unplanned, unintended occupational collective dose for the work activity. When processed through the Occupational Radiation Safety Significance Determination Process, this finding was found to have no more than very low safety significance because the finding was an as low as is reasonably achievable planning issue and Pacific Gas and Electric Company's 3-year rolling average collective dose was less than 135 person-rem (Section 2OS2).

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Diablo Canyon Unit 1 began this inspection period at 100 percent power. On December 10, 2003, operators reduced power on Unit 1 to approximately 24 percent power in anticipation of high swells and kelp impacting the traveling screens. On December 11 operators increased reactor power to 53 percent to support a leak search in the main condenser. Following the search for the leak, operators increased reactor power and Unit 1 reached 100 percent power on December 12. 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 December 10, 2003, operators reduced power to approximately 24 percent power in anticipation of high swells and kelp impacting the traveling screens. Following the high swells, operators increased reactor power on December 11 and achieved 100 percent power on the same day. Unit 2 remained at 100 percent power for the duration of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignments (71111.04)

The inspectors performed four partial system walkdowns and one complete system walkdown during this inspection period.

Partial System Walkdowns

.1 Unit 2 Startup Transformer 2-1

a. Inspection Scope

On October 21, 2003, while Diesel Engine Generator (DEG) 2-2 was in a maintenance outage window, the inspectors performed a partial system walkdown of Startup Transformer 2-1. The inspectors observed valve alignment, material condition, labeling, lubrication, and structural support. The inspectors used Procedure OP J-2:II, “Startup Bank Return to Service,” Revision 18, for reference during the inspection.

b. Findings

No findings of significance were identified.

.2 Unit 1 DEG 1-1

a. Inspection Scope

On October 27, 2003, while DEG 1-2 was in a maintenance outage window, the inspectors performed a partial system walkdown of DEG 1-1. The inspectors reviewed valve alignment, leakage, electrical power availability, labeling, lubrication, ventilation, seismic supports, and absence of physical interference. The inspectors used the following documents as reference during the inspection:

- Procedure OP J-6B:I, “Diesel Generator 1-1 Make Available,” Revision 26

- Drawing 106721, “Diesel Engine - Generator”
  - Sheet 3, Revision 43
  - Sheet 4, Revision 37
  - Sheet 5, Revision 27
  - Sheet 6, Revision 40

b. Findings

No findings of significance were identified.

.3 Unit 2 Residual Heat Removal (RHR) Pump 2-2

a. Inspection Scope

During a plant status walkdown on November 5, 2003, the inspectors noticed a slight accumulation of bearing oil at the base of RHR Pump 2-2. The inspectors reported the potential oil leak to operators, who in turn initiated Action Request (AR) A0594205. The inspectors followed up with Pacific Gas and Electric Company’s (PG&E’s) actions regarding the potential oil leak by performing a partial system walkdown of RHR Pump 2-2 on November 6. The inspectors used the following documents during the partial system walkdown:

- A0533113, “RHR Pump 2-2 Oil Leak”
- A0594205, “RHR PP 2-2 Motor Oil at Base of Pump”

b. Findings

No findings of significance were identified.

.4 Unit 2 Radiation Monitors

a. Inspection Scope

On November 5, 2003, while Radiation Monitor Power Supply Transformer TPRM21 was in a maintenance outage window, the inspectors performed a partial system walkdown of Unit 2 radiation monitors. The inspectors reviewed valve alignment, electrical power availability, labeling, operational status, ventilation, seismic supports, and absence of physical interference. The inspectors used Clearance 76058 and Technical Specification Sheet T0047944.

b. Findings

No findings of significance were identified.

Complete System Walkdown

Unit 1 Control Room Ventilation System (CRVS)

a. Inspection Scope

The inspectors performed a complete system walkdown of the Unit 1 control room ventilation system on November 12, 2003. During the walkdown, the inspectors observed proper system alignment and material condition. The inspectors also reviewed past and present deficiencies. The inspectors used Drawing 106723, “Ventilation and Air Conditioning,” Sheet 16, Revision 82. The inspectors also reviewed the ARs listed in Attachment 1.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

The inspectors performed four fire protection walkdowns and one fire drill review during this inspection period.

.1 Routine Observations

a. Inspection Scope

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

- Units 1 and 2, 4kV switchgear rooms in the turbine building

- Units 1 and 2, switchgear rooms of the auxiliary building

b. Findings

No findings of significance were identified.

.2 Fire Drill

a. Inspection Scope

The inspectors verified the capability of the fire brigade to effectively prevent and fight fires at the Diablo Canyon Power Plant. Specifically, the inspectors reviewed the qualification and training of the operations responder position. The purpose of the operations responder is to provide a communications link between the control room and the incident commander (fire brigade leader), provide fire and fire protection system status information, and support protection of safe shutdown equipment. The inspectors interviewed PG&E operators and fire protection personnel, and reviewed fire protection documents as part of the inspection effort.

b. Findings

Introduction. The inspectors identified a violation of Technical Specification 5.4.1.d, which requires written procedures be established, implemented, and maintained covering the Fire Protection Program implementation. Specifically, PG&E failed to adequately establish and implement a procedure that provided for senior control operators, licensed control operators and nonlicensed, Level 8 nuclear operators to serve in the operator responder position. The inspectors noted that the applicable attachment to the procedure for conduct of the operations response position was not established until after training had been provided on implementing the procedure. Operations responders supporting the fire brigades exhibited a knowledge weakness in activities such as communications with the control room, manual actuation of fire suppression equipment, and providing information to the fire brigade regarding safe shutdown equipment. The failure to adequately establish the procedure and its attachment and implement the procedural changes through effective training resulted in an adverse change in the fire protection program, during the period the violation existed.

Description. Prior to 1998, the fire brigade leader was a senior control operator and the fire brigade members were licensed and nonlicensed operators. The senior control operator possessed knowledge of fire protection systems, safe shutdown equipment, and other plant equipment, and also acted as a liaison to the control room. Following the change to a professional fire brigade in 1998, senior control operators were assigned to be the operations responder to a fire event. In this position, they primarily acted as a liaison between the control room and the fire brigade and provided limited recommendations for protecting safe shutdown equipment.

On August 29, 2003, PG&E instituted an additional change to the operations responder position. In addition to using the senior control operators, licensed control operators and nonlicensed, Level 8 nuclear operators could be used as operations responders. A 2-hour training session was provided to nuclear operators on the duties of an operations responder, prior to August 29, 2003. The training session was outlined in Lesson Number R032C12, “Operations Responder Responsibilities.” Procedure CP M-6, “Fire,” Revision 2, included a checklist for the operations responder duties in Attachment 4.2, “Operations Responder Checklist.” However, the procedure and checklist were not issued until September 12, 2 weeks after licensed control operators and nuclear operators could serve as operations responders.

The inspectors interviewed various control operators and nuclear operators and identified the following deficiencies and issues concerning the operations responder position:

- Senior control operators and licensed control operators had not received formal training on the operations responder position.
- A majority of the operators served on the fire brigade before the professional fire brigade took over, and they expressed a higher degree of confidence in performing the duties of the operations responder, as compared to those who did not have prior fire brigade experience.
- More than one of the operators did not know the phone number for accessing the fire conference bridge, and others had learned about the protocol for the fire conference bridge the day the interview was performed.
- The operators expressed a desire for more thorough training on the operations responder position.
- The operators were not aware that Attachment 4.2 of Procedure CP M-6, titled “Operations Responder Checklist,” existed.
- The operations responder position does not have a qualification card, nor is it part of requalification training for operators.
- Action Request A0579928 stated that, as of August 29, 2003, all Level 8 nuclear operators had received the operations responder training, but the inspectors interviewed one nuclear operator that had not received the training.
- The control operators and nuclear operators had not participated in drills with the fire brigades and identified a lack of interaction with the brigades.

In addition to interviews, the inspectors compared Attachment 4.2 of Procedure CP M-6 to Lesson R032C12, “Operations Responder Responsibilities.” The inspectors noted the following items were missing from the lesson plan when compared to Attachment 4.2. The lesson plan did not discuss:

- The need for the operations responder to be on the fire conference call by dialing onto the associated bridge;

- The need to pick up the radio, pre-plans, and checklist from the fire equipment storage locker before reporting to the incident commander;

- The combination to the fire equipment storage locker although all operators that were interviewed knew the combination;

- The need for the operations responders to identify and communicate which fire doors are propped open; and

- Manual actions when the automatic fire suppression systems did not operate.

Section 9.5 of the FSAR Update outlines PG&E's compliance with NRC Branch Technical Position APCSB 9.5-1. Table B-1 of Appendix 9.5B, "Regulatory Compliance Summary," states, in part, the following aspects of Branch Technical Position APCSB 9.5-1 for which PG&E is committed to comply with:

- <u>Personnel</u>

  ". . . the FSAR should discuss the training and the updating provisions such as fire drills provided for maintaining the competence of the station fire fighting and operating crew . . .

- <u>Fire Brigade Organization, Training, and Equipment</u>

  "Basic training is a necessary element in effective fire fighting operation. In order for a fire brigade to operate effectively, it must operate as a team. All members must know what their individual duties are."

The inspectors determined that PG&E failed to comply with the above items since all fire brigade members did not know what their individual duties are. The inspectors observed that PG&E does not consider the operations responder as part of the fire brigade; therefore, they provided little or no training to the operations responders. Prior to the implementation of the professional fire brigade in 1998, the operations responder duties were performed by the fire team leader who was a senior control operator. When PG&E implemented the professional fire brigade, the operations knowledge was separated out from the fire brigade and given to the operations responder. Therefore, without the presence of a competent operations responder, the fire brigade's capability would be adversely impacted following the 1998 fire brigade change. Since senior control operators had performed the function of the fire brigade leader prior to the professional fire brigade implementation, the senior control operators indicated they were comfortable filling the operations responder position. However, operators who had no prior experience on the fire brigade indicated they were not comfortable with performing the operations responder duties.

Analysis. The performance deficiency associated with this finding is a failure to adequately establish and maintain Procedure CP M-6. The finding impacted the procedure quality objective under the mitigating systems cornerstone and was more than minor since there was an adverse impact to a fire protection defense-in-depth element. Using the Significance Determination Process (SDP) Phase I Screening Worksheet and the SDP Phase II Notebook in Appendix F of Inspection Manual Chapter (IMC) 0609, the inspectors determined that the finding was of very low safety significance. Specifically, the significance of the finding was evaluated by considering fire scenarios in the vital 4 kV Bus F switchgear room and auxiliary saltwater Pump 1-1 vault. These two areas have the highest dependence on fire brigade response since they have the highest fire ignition frequency for areas that do not have automatic fire suppression. The inspectors evaluated the risk-significance using half of the nominal credit for manual fire suppression as a result of the finding. Using Tables 5.4, 5.5, and 5.6 of IMC 0609, both fire scenarios screened as very low safety significance. Since the two fire scenarios were considered worst-case for the finding, the inspectors determined that the finding was of very low safety significance.

Enforcement. The inspectors identified a violation of Technical Specification 5.4.1.d, which requires written procedures be established, implemented, and maintained covering the Fire Protection Program implementation. Specifically, PG&E failed to adequately establish and implement Procedure CP M-6 for senior control operators, licensed control operators, and non-licensed operators to serve in the operations responder position. The inspectors noted that Attachment 4.2 of the procedure was not established until after operators could be assigned the operations responder position. Because the failure to establish and implement Procedure CP M-6 was determined to be of very low safety significance and has been entered into the corrective action program as AR A0597355, this violation is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275; 323/03-08-01, Failure to Establish and Implement Fire Program Procedural Changes for Operations Responders in Support of the Fire Brigade.

1R06 Flood Protection (71111.06)

The inspectors performed one external and one internal flood protection inspection during this inspection period.

.1 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. Specifically, the inspectors walked down the exterior areas of the intake structure, auxiliary building, and turbine building for flood water entry paths. The inspectors used Chapter 3 of the FSAR Update in support of this inspection.

b. Findings

No findings of significance were identified.

.2 Internal 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 internal flood risks. Specifically, the inspectors reviewed corrective action documents and walked down cable pull-boxes. The inspectors verified operable sump pumps and drains, settings for level alarms, and intact condition of cable splices subject to submergence. The inspectors used Probabilistic Risk Assessment Calculation F.4, "PRA Internal Floods Analysis," Revision 4, in support of this inspection.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

The inspectors witnessed one operator requalification training session during routine training in the simulator. 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. The inspectors witnessed simulator training involving shutting down and return to power of an operating unit using the new digital electrohydraulic control system, including startup and connecting the unit to the electrical grid. In addition, operators performed a surveillance of the reactor protection system with respect to the turbine control and stop valves. The inspectors used Procedures L-3, "Secondary Plant Startup," Revision 28; L-4, "Normal Operation at Power," Revision 44; OP C-3:II, "Main Unit Turbine-Startup," Revision 33; and OP C-3:III, "Main Unit Turbine-At Power Operations," Revision 12A, to support the inspection activities.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors performed three inspections 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 11, was used as guidance. The inspectors reviewed the following ARs:

- A0576813, Maintenance Rule Performance Criteria, Goal Setting Review for Units 1 and 2 Containment Isolation Valves
- A0574369, Maintenance Rule Performance Criteria, Goal Setting Review for Unit 1 Auxiliary Feedwater System
- A0584097, Maintenance Rule Performance Criteria, Goal Setting Review for Units 1 and 2 Containment Fan Cooler Unit Drain Collection System

b. Findings

Introduction. A Green noncited violation was identified by the inspectors for the failure to adequately monitor the performance of the Unit 1 auxiliary feedwater (AFW) system in accordance with 10 CFR 50.65(a)(2).

Description. On October 31, 2003, the inspectors reviewed a 10 CFR 50.65(a)(1) evaluation in AR A0574369 for the Unit 1 AFW system. The inspectors noted a series of AFW system water contaminations that were first noted in June 2001. Contaminates included chlorides and other minerals and elements commonly found in natural water supplies near the plant. The cause of the AFW system water contaminations was due to incorrect travel stop settings for Valve FW-1-FCV-437. Valve FW-1-FCV-437 is a butterfly valve that utilizes a Limitorque HBC gear drive and a handwheel to manually actuate the valve. The safety function of the valve is to open and allow water from the raw water reservoir to be used as a backup to the condensate storage tank and the firewater storage tank. Since the travel stops were not at the proper setting, they prevented the valve from fully closing, thus allowing water from the raw water reservoir to enter the AFW system and result in contamination. PG&E staff discovered that the travel stops were set during preventive maintenance, but moved when the valve was actuated. The travel stops moved because the cover of the travel stop box on the HBC drive did not secure the travel stop nuts. PG&E is initiating corrective actions to prevent the travel stops from moving. Other similar valves in Units 1 and 2 have been evaluated for travel stop movement. No other valves were found to exhibit the same condition.

Due to the water contamination, operators cleared portions of the Unit 1 AFW system in order to flush the system. The Unit 1 AFW system incurred additional hours of unavailability time for the flushing operation. Per AR A0574369, the performance criteria for the Unit 1 AFW system to remain monitored under 10 CFR 50.65(a)(2) has an unavailability time less than or equal to 67.17 hours. The total unavailability time for the Unit 1 AFW system was 69.18 hours. Despite exceeding the unavailability performance criteria, PG&E continued to monitor the Unit 1 AFW system under 10 CFR 50.65(a)(2) for two reasons. First, they believed the root causes and corrective actions under Nonconformance Reports (NCR) N0002129 and N0002148 were sufficient to address the issue and to prevent a similar event from recurring. Second, the cause of the contamination events was due to improper maintenance practices and not equipment failures. Therefore, PG&E staff felt that the corrective actions for contamination events were related to human performance and that the issue was outside the intentions of 10 CFR 50.65(a)(1).

The inspectors determined that PG&E did not meet the requirements of 10 CFR 50.65(a)(2) when the Unit 1 AFW system exceeded the unavailability time goals and was not placed in 10 CFR 50.65(a)(1). The inspectors identified that the corrective actions under NCRs N0002129 and N0002148 did not fully address the issues with the Unit 1 AFW system water contamination. PG&E initiated a third NCR, N0002167, to address the movement of Valve FW-1-FCV-437 travel stops due to the clearance between the travel stop box cover and the travel stop nuts. NCR N0002167 also contained actions to address the failure of the two previous NCRs to identify and correct the cause of the Unit 1 AFW system water contamination. NCR N0002167 was initiated after AR A0574369 documented that corrective actions under NCRs N0002129 and N0002148 were sufficient to address the cause of the water contamination.

The inspectors determined that PG&E's conclusion regarding human performance and 10 CFR 50.65 was incorrect. Specifically, PG&E did not consider human performance errors during maintenance activities to be within the scope of 10 CFR 50.65, even if human performance errors resulted in a maintenance preventable functional failure or unavailability time. 10 CFR 50.65(a)(2) states, in part, that monitoring under 10 CFR 50.65(a)(1) is not required if it has been demonstrated that the performance or condition of a structure, system, or component is being effectively controlled through the performance of appropriate preventive maintenance. The inspectors identified the human performance errors, regarding preventive maintenance, on Valve FW-1-FCV-437 to be inappropriate, resulting in the Unit 1 AFW system incurring additional unavailability time for flushing.

Analysis. The inspectors determined that PG&E's failure to adequately monitor the performance of the Unit 1 AFW system in accordance with 10 CFR 50.65(a)(2) was a performance deficiency. The finding impacted the mitigating systems cornerstone objective to ensure the availability and reliability of the AFW system to respond to initiating events and is greater than minor, using Example 1.f of Inspection Manual Chapter (IMC) 0612, Appendix E. Similar to the example, the inspectors discovered that PG&E staff did not consider unavailability time for the Unit 1 AFW system, although the unavailability time was due to prior poor maintenance practices on Valve FW-1-FCV-437. With the unavailability time considered, PG&E's 10 CFR 50.65(a)(2) evaluation was invalid. Using the SDP Phase I worksheet in IMC 0609, Appendix A, the finding is of very low safety significance, since there was no loss of an actual safety function, no loss of a safety-related train for greater than the Technical Specification allowed outage time, and the finding is not potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event.

Enforcement. 10 CFR 50.65(a)(2) states, in part, that monitoring as specified in 10 CFR 50.65(a)(1) is not required where it has been demonstrated that the performance or condition of a structure, system, or component is being effectively controlled through the performance of appropriate preventive maintenance, such that the structure, system, or component remains capable of performing its intended function. However, PG&E did not consider all the unavailability time for the Unit 1 AFW system when reviewing the system's status in 10 CFR 50.65(a)(2). The performance criteria for the Unit 1 AFW system to remain monitored under 10 CFR 50.65(a)(2) was exceeded, in part, because of the human performance errors such that PG&E did not demonstrate that the performance of the system was being effectively controlled through the performance of appropriate preventive maintenance. Because the failure to adequately monitor performance of the Unit 1 AFW system according to 10 CFR 50.65(a)(2) is of very low safety significance and has been entered into the corrective action program as AR A0595257, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/03-08-02, Failure to Adequately Monitor Auxiliary Feedwater System According to 10 CFR 50.65(a)(2).

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

The inspectors performed five inspection samples of maintenance risk assessments and 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 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, maintenance outage windows for Component Cooling Water Heat Exchanger 1-2, Atmospheric Dump Valve MS-1-PCV-19, and Positive Displacement Pump 1-3 on September 30

- Unit 2, Eagle 21 Protection Set Rack 13 Nonvolatile Random Access Memory replacement and Atmospheric Dump Valve MS-2-PCV-20 calibration on October 23

- Units 1 and 2, 500 kV breaker replacement work on November 6

b. Findings

No findings of significance were identified.

.2 Emergent Work

a. Inspection Scope

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

- Unit 2, Valve FCV-495 actuator replacement
- Unit 1, Valve SI-1-8890 packing leakage

b. Findings

No findings of significance were identified.

1R14 Operator Performance during Nonroutine Evolutions and Events, Including Followup in Response to Earthquakes Impacting Diablo Canyon Power Plant (71111.14)

a. Inspection Scope

The inspectors reviewed three inspection samples (two earthquakes and high Pacific Ocean swells) of nonroutine evolutions or events.

.1 Earthquakes In the Vicinity of the Diablo Canyon Power Plant

Background

Diablo Canyon Power Plant is located in a seismically active area along the interface of the Pacific and North American Plates. Several faults are located within 50 miles of the plant. PG&E is required by the operating license to maintain a Long-Term Seismic Program to reevaluate the seismic design bases against insights and knowledge gained with each seismic event. FSAR Update Section 3.7 describes the seismic design basis of the facility. The plant was designed for ground motion from a Design Earthquake, equivalent to an "Operating Basis Earthquake," in which the plant can be expected to continue to operate. This value is ground motion acceleration at the containment base of 0.2g. The Double Design Earthquake, equivalent to a “Safe Shutdown Earthquake,” is the design basis for most safety-related structures, and has ground motion acceleration of 0.4. The plant is also evaluated for the maximum ground acceleration which can result from an earthquake originating in the Hosgri fault. This evaluation ensures the plant can be safely shut down if the expected maximum ground motion were to occur.

Technical Specification 3.3.1, "Reactor Trip System," requires instrumentation to initiate a reactor trip for a nominal ground acceleration of 0.35 g. An earthquake force monitor, which has three sensors, provides an alarm in the control room at a minimum of 0.01g of ground acceleration. Procedure CP M-4, “Earthquake,” Revision 18, addresses the actions required to be taken in the event of an earthquake of 0.01 g or greater.

Deer Canyon Earthquakes

Description

At 12:52 a.m., on October 18, 2003, Diablo Canyon Power Plant Units 1 and 2 declared a Notification of Unusual Event (NOUE) because an earthquake that measured 3.4 was felt by the control room operators. No damage to plant equipment was observed and both units remained at 100 power throughout the event.

A preshock occurred at 12:27 a.m. that lasted approximately 3 seconds and was felt by the control room operators. No alarms or other effects were noted. The primary shock occurred at 12:39 a.m. and lasted approximately one second. The epicenter of the seismic event was located 2.8 miles east-southeast of the plant (within the owner controlled area) and measured 3.4. The primary shock resulted in momentary turbine bearing high vibration alarms on both units and a high level alarm on the Unit 1 Safety Injection Accumulator 1-3. The plant's seismic monitor recorded a peak acceleration of 0.02 g.

Following declaration of the NOUE, operators entered Procedure CP M-4, which contained instructions for response to earthquakes detected at the site. The shift manager initiated a preliminary evacuation of the intake structure (where valve maintenance was in progress) until the extent of the seismic event was understood. PG&E performed walkdowns of both containments and all vital areas to ensure no immediate structural damage was evident. PG&E performed enhanced monitoring of safety-related tank levels to ensure no ruptures occurred. No damage to any plant equipment was identified.

Following confirmation that the earthquake resulted in no plant damage, PG&E exited the NOUE at 3:30 a.m. The inspectors responded to the site to monitor PG&E's actions and verified that PG&E performed the actions prescribed by Procedure CP M-4. The inspectors walked down safety-related areas of the plant and noted no evidence of damage that would affect safety system operability. The inspectors continued to examine the status of structures following the October 18, 2003, earthquake during routine plant status walkdowns throughout the inspection period.

The inspectors reviewed Special Report 50-275;323/03-03-00, "Seismic Event of October 18, 2003," which discussed the Deer Canyon earthquakes of October 18 and provided analysis of the effects of the earthquakes on plant structures, systems, and components. The inspectors found the report properly analyzed the seismic data and the impact that the ground motion had on structures, systems, and components.

San Simeon Earthquake 35 Miles Northwest of the Site

Description

At approximately 10:30 a.m. PST on December 22, 2003, the resident inspectors heard a noise on the roof of the Diablo Canyon administrative building. The inspectors responded to the control room to report this information to the shift manager. The shift manager received similar reports from personnel in the warehouse and the training building outside the protected area. The inspectors and the operators verified that no alarms were received in the control room and that the seismic monitor did not register this event. The shift manager and the inspectors reviewed Procedure CP M-4 and verified that no action was required.

At 11:16 a.m. PST a magnitude 6.5 earthquake struck 35 miles north-northwest of Diablo Canyon. Both resident inspectors were at the site. The shaking lasted 22 seconds. The senior resident inspector (SRI) immediately contacted the Region IV branch chief and informed the branch chief that an earthquake had been felt.

While the SRI was briefing Region IV, the resident inspector (RI) responded to the control room at 11:18 a.m. to observe the operators. The RI walked down the panels, reviewed the status of safety systems, and verified that PG&E was implementing the emergency plan. The RI noted that the seismic monitor recorded a seismic event of 0.04g. The RI established the NRC's reactor safety counterpart link and advised the NRC headquarters operations officer that PG&E would soon be declaring a NOUE.

The SRI reported to the control room to observe PG&E actions. The inspectors verified that the requirements of Procedure CP M-4 were followed. The procedure required verification of the tank levels of all of the major safety-related tanks to ensure that no catastrophic failures of the important tanks had occurred. The inspectors verified the applicable tank levels. The procedure also required a complete walkdown of plant areas. PG&E received annunciators for the Unit 1 spent fuel pool level and safety injection accumulator high and low levels for both units during the seismic event because of sloshing of the water. Operators received temporary alarms that included high vibration for the Unit 1 turbine. The operating electrohydraulic control pump tripped and was immediately restarted. Operators cleared the alarms following the shaking.

PG&E declared a NOUE at 11:22 a.m. The inspectors verified that PG&E made the required calls to the state and local officials. PG&E sent personnel to the Emergency Operating Facility (EOF), which is co-located with the San Luis Obispo County Office of Emergency Services to assist in monitoring the community and the emergency services response. PG&E established a video conference between the EOF and the shift manager's office for the next 24 hours. One of the inspectors was present in the shift manager's office during each of the updates between the EOF and the control room. The EOF advised the control room of damage to Highway 46 and fallen rocks on Highway 41, which is an emergency evacuation route. The inspectors communicated the status of local roadways to Region IV. Highways 46 and 41 had debris on the road, and Highway 46 experienced some buckling, but the highways were passable for emergency response purposes. In addition, personnel in the EOF communicated the status of several emergency sirens that were inoperable because of the power outages in San Luis Obispo county.

Fifty-six of the 131 emergency sirens were inoperable because of power outages. Alternate means of notifying people within the affected areas were available. As of

3:40 p.m., on December 22, 2003, 35 sirens were without power, and at 6 p.m. 26 sirens were still without power. At 1:30 a.m., on December 23, 2003, four sirens were without power. The remaining four were restored in the subsequent 24 hours.

The inspectors monitored reports of PG&E walkdowns of the plant. At approximately 3 p.m., the RIs began independent inspections of plant equipment, for Phase I of the NRC inspection plan following the earthquake. One RI remained in the control room to monitor operator actions and maintain communications within the agency, while the other inspector walked down plant areas.

The inspectors walked down the turbine building first. The emergency diesel generators, the component cooling water heat exchangers, and high voltage switchgear are in this building. The inspectors verified that no leaks existed in the safety-related systems and that no cracks were evident in structural members.

The inspectors then walked down the switchgear areas of the auxiliary building. The inspectors verified that no damage occurred in the ac and dc switchgear rooms, the cable spreading room, and the battery rooms.

The inspectors entered the radiologically controlled area of the auxiliary building and performed complete inspections of the emergency core cooling pumps and systems, component cooling water pumps, auxiliary feedwater pumps, and RHR system heat exchangers.

The inspectors entered the fuel building and verified the level in the spent fuel pools. All structural elements in the spent fuel pool were unaffected. Spent fuel pool water clarity was good. No cracks were evident in the fuel building ventilation system or structural members.

The inspectors walked down the outside areas of the plant. The inspectors verified that the applicable security barriers were still intact. The inspectors verified that the major outside tanks (condensate storage tanks, refueling water storage tanks, primary water storage tanks, and fire water storage tank) had no cracks or obvious damage. The inspectors toured the intake structure and verified that no damage occurred to the traveling screens and auxiliary saltwater pumps, pipes, and valves.

The RIs provided continuous site coverage until PG&E exited the NOUE. Because the area continued to experience aftershocks, PG&E elected to remain in a NOUE for approximately 24 hours. The RIs continued to inspect the facility and monitor control room actions for the duration of the NOUE. During the evening, the inspectors walked down the offsite power sources (startup transformers) and continued to monitor communications with the emergency facilities. The inspectors examined the auxiliary and startup transformers for damage. PG&E personnel reported that two switches were damaged in the 230 kV system at the offsite Morro Bay switchyard. The Morro Bay switchyard is one source of offsite power to the startup transformers. PG&E declared the startup transformers inoperable to provide safe electrical isolation and cleared the 230 kV lines to support replacement of the damaged switches. The startup transformers were returned to operable status within the 72-hour limiting condition for operation action statement. The RIs remained at the site, continuing to inspect and monitor PG&E actions until 2 p.m. PST on December 23. PG&E exited the NOUE at approximately 12:15 p.m., PST on December 23, 2003.

In the days following the event, the inspectors continued to review PG&E's response to aftershocks and the adequacy of the PG&E procedures and the Emergency Plan. The inspectors attended PG&E's Event Review Team meetings throughout the remainder of the inspection period.

a. Findings

During the inspections, no system or structural damage or evidence of differential deflections were detected, and no site ground effects were noted during exterior visual inspections. In addition, no damage was noted to the administration building, which is designed to the Uniform Building Code. The licensee's immediate response to the earthquake was effective in ensuring continued safe operation, and their implementation of the NRC's prompt notification requirements was timely and correct.

All seismic instrumentation functioned correctly. The NRC inspectors conducted a review of the required surveillances on seismic monitoring instruments. All instruments were correctly calibrated. The inspectors noted that the licensee is in the process of upgrading the current Earthquake Force Monitor to a digital distributed system that will provide better information (e.g., wider frequency response and more monitoring locations).

Casualty Procedure M-4 was used in responding to the earthquake. Although overall response to the earthquake was adequate, several lessons were learned by PG&E from a subsequent review of the implementation of the procedure. PG&E has begun a general revision to improve its quality based on this experience.

The inspectors reviewed PG&E's reportability procedure for loss of the early warning system sirens. During the review, the inspectors noted that the procedure for notification of the NRC for a loss of the early warning system sirens only addressed sirens within a 10-mile radius and not the entire Diablo Canyon Emergency Planning Zone, as defined in the Emergency Plan. In this case, the licensee did inform the NRC of the loss at the time the Unusual Event notification was made.

.2 Units 1 and 2 Downpowers because of High Pacific Ocean Swells

a. Inspection Scope

On December 9, 2003, PG&E received warning of impending high Pacific Ocean swells. Upon notification of the high swells, PG&E management determined that the units would be ramped down to approximately 25 percent power to prevent the traveling screens, from being clogged with kelp, which could necessitate tripping the circulating water pumps and a reactor trip of the affected unit. At 1:30 a.m., on December 10, operators slowly decreased power on both units. The inspectors responded to the site and monitored the operator performance during the downpower and operator response to any high differential pressure across the traveling screens.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds

a. Inspection Scope (71111.16)

The inspectors reviewed three samples of operator workarounds.

The inspectors reviewed PG&E’s documented actions in which degraded conditions or changes to accident analyses required additional operator action beyond that credited in the design basis to compensate for these conditions. PG&E tracked two types of these conditions: operator burdens and operator workarounds.

PG&E defined an operator burden as a manual action taken to compensate for degraded equipment that affected normal operation of a unit. PG&E had 17 operator burdens.

PG&E defined an operator workaround as a manual action taken to compensate for a degraded condition required for response to abnormal or emergency operating procedures. PG&E had 17 active operator workarounds. The inspectors assessed the cumulative affect of the operator workarounds to determine if operators would be overly taxed with working around numerous degraded conditions that would complicate an abnormal or emergency condition.

The NRC inspectors reviewed PG&E’s program for tracking the operator workarounds and restoring the applicable systems to full qualification to determine if PG&E appropriately managed these items. None of the operator workarounds involved risk-significant actions.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed eight postmaintenance tests for selected risk-significant systems to verify their operability and functional capability. As part of the inspection process, the inspectors witnessed and/or reviewed the postmaintenance test acceptance criteria and results. The test acceptance criteria was compared to the

Technical Specifications and the FSAR Update. Additionally, the inspectors verified that 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 corrective maintenance activities were reviewed by the inspectors:

- Unit 1, Thermocouple Monitoring System Trains A and B reconnection following open thermocouple detection circuit on April 13 and 26, 2002 (Work Orders C0176158 and C0176579)
- Unit 1, RHR Pump 1-2 inspection for water intrusion into terminal box on January 14 (Work Orders C0178108 and C0178123)
- Unit 2, Diesel Engine Generator 2-1 routine maintenance outage window on September 30 (Work Orders R0240283, R0231007, and R0231009)
- Unit 2, Diesel Engine Generator 2-3 high pressure fuel line leak repair on October 9 (AR A0592470 and Work Order C0184992)
- Unit 1, Atmospheric Dump Valve MS-1-PCV-21 calibration on October 21-22 (Work Orders R0245981 and R0245983)
- Unit 1, Diesel Engine Generator 1-2 air start motor preventive maintenance on October 27 (Work Order C0182839)
- Unit 1, Auxiliary Building Ventilation System Exhaust Fan E-1 preventive maintenance on December 2 (Work Order R0228685)
- Unit 1, Pressure Balancing Valve SI-1-8890A packing replacement and repair tool installation on December 3 (Work Order C0185920)

b. Findings

Introduction. A Green noncited violation was identified by the inspectors for failure to adequately evaluate the capability of core exit thermocouples to measure radial temperature gradient for Quadrant 1 of the Unit 1 reactor core, as required by 10 CFR Part 50, Appendix B, Criterion III.

Description. During Refueling Outage 1R11, maintenance personnel disconnected the core exit thermocouple connections on top of the Unit 1 reactor vessel head for reactor vessel head removal for refueling operations. On April 26-27, 2002, maintenance personnel concluded reconnection of the core exit thermocouples on top of the Unit 1 reactor vessel head. On September 10, 2003, reactor engineers identified a discrepancy among several of the core exit thermocouple temperature readings while performing an in-core flux map. The reactor engineers noticed that some of the thermocouples were reading lower than expected temperatures and others were reading higher than expected temperatures. A troubleshooting team evaluated the discrepancies and concluded that maintenance personnel had incorrectly swapped the Trains A and B thermocouple connectors at Port 79 on the reactor vessel head. Maintenance personnel and operators did not identify the incorrect connection prior to reactor startup, since the temperature readings were uniform for all thermocouples. The discrepancy in thermocouple readings becomes noticeable at full reactor power when the thermocouples near the center of the reactor core read higher than those towards the outside of the core. However, operators did not notice the discrepancy at full power operation since they checked to see if the thermocouple readings were in a valid range rather than checking to see if the readings were an expected value.

The inspectors reviewed the Technical Specification bases documents for core exit thermocouples and identified the following design aspects:

- At least two channels of valid core exit thermocouples per quadrant are required, with a channel consisting of two thermocouples.

- In a channel, one thermocouple must be near the core center and the other must be near the core periphery in order to measure radial temperature gradient.

- The two channels must ensure that a single failure will not disable the ability to determine radial temperature gradient.

The inspectors observed that PG&E did not take credit for the swapped thermocouples, leaving only 6 operable thermocouples in Quadrant 1 of the reactor core. The inspectors questioned whether the possible core exit thermocouple pairs for each train could meet the requirement for measuring radial temperature gradient. Specifically, Train A relied on a combination of Thermocouple 15 with Thermocouples 1 or 11. Thermocouple 15 had three assemblies from the outside of the core, while Thermocouples 1 and 11 had one and two assemblies from the outside of the core, respectively. Similarly, Train B relied on a combination of Thermocouple 5 with Thermocouples 14 or 36. Thermocouple 5 had three assemblies from the outside of the core, while Thermocouples 14 and 36 had one and two assemblies from the outside of the core, respectively. When the inspectors requested design bases information for the selection of thermocouple pairs for each quadrant, PG&E was not able to provide the design documents or an adequate technical basis for the selection.

The inspectors reviewed AR A0528665, which was initiated in April 4, 2001. The AR requested a clarification of the core exit thermocouple surveillance procedure with the design bases. However, the AR failed to adequately address the technical basis for the location of thermocouples for measuring radial temperature gradient within the reactor core. The inspectors determined that both core exit thermocouple channels for Quadrant 1 of the Unit 1 reactor could be considered operable if appropriate compensatory actions/modifications were taken. Specifically, the swapped thermocouples continued to provide reliable temperature information, but in the wrong locations. The inspectors observed that PG&E posted a sign on the Unit 1 thermocouple monitoring system, indicating the swapped thermocouples and what locations of the core they were actually measuring temperature.

Analysis. The inspectors determined that, following the swapping of core exit thermocouples, PG&E’s failure to adequately evaluate the technical bases for measuring radial temperature gradient within the reactor core was a performance deficiency. The finding impacts the mitigating system cornerstone through degraded overall availability of the components within a system used to assess and respond to initiating events to prevent undesirable consequences and was greater than minor when compared to Example 3.a of IMC 0612, Appendix E. Similar to Example 3.a, PG&E staff performed additional work to verify the ability of the core exit thermocouples to measure radial temperature gradient within Quadrant 1 of the Unit 1 reactor core. Using the SDP Phase 1 screening worksheet from IMC 0609, Appendix A, the finding was determined to be of very low safety significance, since the deficiency was confirmed not to result in loss of function per Generic Letter 91-18, Revision 1.

Enforcement. 10 CFR Part 50, Appendix B, Criterion III, states, in part, that measures shall be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of structures, systems, and components. Contrary to the above, PG&E failed to adequately address the suitability of the remaining operable Quadrant 1 core exit thermocouples for measuring core radial temperature gradient. Because this failure to provide adequate technical basis for core exit thermocouple operability is of very low safety significance and has been entered into the corrective action program as AR A0597575, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/03-08-03, Failure to Provide Adequate Technical Bases for Core Exit Thermocouple Radial Temperature Measurement.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors performed three inspection samples of surveillance testing.

The inspectors evaluated several 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. The inspectors performed a technical review of the procedure, witnessed portions of the surveillance test, and reviewed the completed test data. The inspectors also considered whether proper test equipment was utilized, preconditioning occurred, test acceptance criteria agreed with the equipment design basis, and equipment was returned to normal alignment following the test. The following tests were evaluated during the inspection period:

- Procedure STP I-1C, “Routine Weekly Checks Required By Licenses (Unit 1),” Revision 77 on October 9

- Procedure STP P-AFW-21, "Routine Surveillance Test of Turbine Driven Auxiliary Feedwater Pump 2-1," Revision 16, on October 16

- Procedure STP I-2D, “Nuclear Power Range Incore/Excore Calibration,” Revision 48 on November 18

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed two inspection samples of temporary plant modifications.

The inspectors reviewed a sample of two temporary plant modifications that could potentially impact the mission of important safety systems. Temporary plant modifications include jumpers, lifted leads, temporary systems, repairs, design modifications, and procedure changes which can introduce changes to plant design or operations. There were 30 active temporary modifications during this inspection period. Inspection activities included a review of the temporary modification impact on: (1) operability of equipment, (2) energy requirements, (3) material compatibility, (4) structural integrity, (5) environmental qualification, (6) response time, and (7) logic and control integration. The inspectors also verified the design and alignment of safety systems when the temporary modifications were no longer needed. The following temporary modification was reviewed during this inspection period:

- Unit 1, Measuring and test equipment added to battery Charger 1-2 float feedback circuit for troubleshooting per Work Order C0185038 and AR A0592302

- Unit 1, Add second off-globe valve to 1-04L-41, per Work Order C0184388 and AR A0588971

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert Notification System Testing (71114.02)

a. Inspection Scope

The inspector performed one inspection sample. The inspector discussed the status of offsite siren and tone alert radio systems with the PG&E staff to determine if significant changes had been made to those systems or methods of maintenance and testing of the systems. The inspector reviewed the documents and correspondence associated with the November 2000 Early Warning System Operating System Project Proposal. The inspector compared the current testing and maintenance methods described in EP MT-43, “Early Warning System Testing and Maintenance,” with requirements in 10 CFR Part 50, Appendix E. PG&E’s alert and notification system testing program was compared with criteria in NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants”; Federal Emergency Management Agency (FEMA) Report REP-10, “Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants”; and the PG&E’s FEMA-approved alert and notification system design report.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a. Inspection Scope

One inspection sample was performed. The inspector discussed with PG&E the status of primary and backup systems for mobilizing the emergency response organization during an emergency to determine PG&E’s ability to staff emergency response facilities in accordance with PG&E’s emergency plan and the requirements of 10 CFR Part 50, Appendix E. The inspector reviewed correspondence associated with contracting out the emergency response organization call out function. The inspector reviewed the results of three rapid-response drills conducted following activation of the new call out process. The inspector also reviewed the following documents related to the emergency response organization augmentation system:

- EP G-2, “Interim Emergency Response Organization”
- EP G-3, “Emergency Notification of Off-Site Agencies”

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

One inspection sample was performed. The inspector performed an on-site review of the following Emergency Plan revisions. The revisions were compared to the previous revisions; the criteria of NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants”; and the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the revisions decreased the effectiveness of the emergency plan.

- Revision 4, Change 4 to Tab 5, “Organizational Control of Emergencies,” and Revision 4, Change 3 to Tab 7, “Emergency Facilities and Equipment,” submitted on November 4, 2003. These revisions replaced the on-site health physics communication phone line with a satellite phone system.

- Revision 4, Change 3 to Tab 4, “Emergency Classification,” and Revision 33 to EP G-1, Attachment 7.1, “Emergency Action Level Classification Chart,” submitted November 4, 2003. This revision replaced the control room main annunciator printer with a computer and touch screen monitor to provide the same functions.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

One inspection sample was performed. The inspector reviewed the following documents related to PG&E’s corrective action program to determine PG&E’s ability to identify and correct problems in accordance with 10 CFR 50.47(b)(14) and 10 CFR Part 50, Appendix E:

- Summaries of corrective actions assigned to the emergency preparedness department between September 2001 and October 2003

- Detailed review of 27 action requests

- Annual exercise and quarterly drill self-assessments from October 23, 2002; May 28, 2003; and July 17, 2003

- Emergency Preparedness Self-Assessment, April 9-11, 2003

- 50.54(t) Review, May 11, 2002; and April 4, 2003

- Quality Performance Assessment Report, Third Period 2003, July 1 to September 30, 2003

b. Findings

No findings of significance were identified.

1EP6 Emergency Preparedness Evaluation (71114.06)

a. Inspection Scope

The inspectors witnessed one emergency preparedness drill that included emergency plan implementation conducted on October 29, 2003. The scenario simulated a large break loss-of-coolant accident, coupled with clogging of the containment recirculation sump. The scenario continued with damage to fission product barriers, core damage, and a radiological release to the environment to demonstrate PG&E's capabilities to implement the emergency plan. The inspectors witnessed PG&E performance in the control room (i.e., simulator), the Technical Support Center, and the Emergency Offsite Facility. The inspectors also attended PG&E's self-critique of the scenario. The following procedures were used to evaluate the performance:

- Procedure EOP E-0, "Reactor Trip or Safety Injection," Revision 27
- Procedure EOP E-1, "Loss of Reactor or Secondary Coolant," Revision 18
- Procedure EOP FR-C.1, "Response to Inadequate Core Cooling," Revision 15

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY
Cornerstone: Occupational Radiation Safety

2OS2 As Low as is Reasonable Achievable (ALARA) Planning and Controls (71121.02)

a. Inspection Scope

The inspector completed eight samples of ALARA planning and controls.

The inspector assessed PG&E's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, and high radiation areas, radiation worker practices, and work activity dose results against procedural and regulatory requirements. No high exposure work activities in high radiation or airborne areas were performed during the inspection. Therefore, this aspect could not be evaluated.

The inspector interviewed radiation protection staff and other radiation workers to determine the level of planning, communication, ALARA practices, and supervisory oversight integrated into work planning and work activities. The inspector reviewed initial and emergent work scopes and estimated man-hours provided to the radiation protection group for accuracy. In addition, the following items were reviewed and compared with procedural and regulatory requirements to assess PG&E's program to maintain occupational exposures ALARA:

- Plant collective exposure history for the past 3 years, current exposure trends, source term measurements, and 3-year rolling average dose information
- ALARA program procedures
- Processes, methodology, and bases used to estimate, justify, adjust, track, and evaluate exposures
- Three ALARA prejob, in-progress, and postjob reviews and associated radiation work permit (RWP) packages from Unit 2 Refueling Outage 11 activities which resulted in some of the highest personnel collective exposures (RWPs 03-2002, 03-2044, and 03-2005)
- Temporary shielding program and implementation
- Hot spot tracking and reduction program
- Quality Verification Audit 031700023, Quality Verification Assessment Report for the Third Period 2003, Quality Verification Assessment Report 030410010, and the 2002 Annual Review of the DCPP Radiation Protection Program
- Three ALARA Review Committee meeting minutes (February 6, June 19, and October 14, 2003)
- Declared pregnant worker and embryo/fetus dose evaluation, monitoring, and controls
- Summary of corrective action documents written since the last inspection and selected documents relating to exposure tracking, higher than planned exposure levels, radiation worker practices, and repetitive and significant individual deficiencies.

b. Findings

Introduction. The inspector identified collective doses for reactor coolant pump (RCP) work activities performed during Unit 2 Refueling Outage 11 were not maintained ALARA. Specifically, the inspector determined that the work activity associated with RWP 03-2055, "Reactor Coolant Pump (RCP) 2-2, 10 year inspection," exceeded 5 person-rem and the dose estimation by more than 50 percent.

Description. During a review of RWP packages and accumulated dose for Unit 2 Refueling Outage 11 work, the inspector identified that work associated with RCP 2-2 was originally estimated on January 10, 2003, to be completed for 1.5 person-rem. Due to concerns identified during the inspection of RCP 2-2, the work scope was expanded to include similar work on RCP 2-1. On February 15, 2003, the job dose was properly re-estimated and justified, for the known work scope, to be 2.9 person-rem. However, due to the failure to communicate the full work scope and radiological conditions among the predictive maintenance personnel, the RCP component engineer, and the ALARA staff, the 2.9 person-rem estimate was exceeded. Specifically, the ALARA staff and the RCP component engineer were not informed by the predictive maintenance staff that the maintenance task included numerous motor stator balance efforts that would be performed during the time the steam generators were drained. The job was completed for 5.4 person-rem (86 percent greater than the justified estimate).

Analysis. The failure to maintain collective doses ALARA is a performance deficiency. This finding was more than minor because it is associated with the Occupational Radiation Safety Cornerstone attribute (program and process) and affected the associated cornerstone objective (to ensure adequate protection of worker health and safety from exposure to radiation). This occurrence involved inadequate planning, which resulted in unplanned, unintended occupational collective dose for a work activity. When processed through the Occupational Radiation Safety SDP, this finding was found to have no more than very low safety significance because the finding was an ALARA planning issue and the PG&E's 3-year rolling average collective dose was less than 135 person-rem. PG&E entered this finding into their corrective action program as AR A0595776 (FIN 50-323/2003-08-04, Failure to maintain job dose ALARA).

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

Three inspection samples were performed. The inspector sampled PG&E submittals for the performance indicators listed below for the period from October 31, 2002, through September 30, 2003. The definitions and guidance of NEI (Nuclear Energy Institute 99-02, "Regulatory Assessment Indicator Guideline," were used to verify PG&E's basis for reporting each data element in order to verify the accuracy of performance indicator data reported during the assessment period. PG&E's performance indicator data were reviewed against the requirements of Procedure AWP EP-001, "Emergency Preparedness Performance Indicators."

Emergency Preparedness Cornerstone:

- Drill and Exercise Performance (DEP)
- Emergency Response Organization Participation (ERO)
- Alert and Notification System Reliability

The inspector reviewed a sample of drill and exercise scenarios and licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. PG&E's performance was reviewed against the requirements of the PG&E's Emergency Plan and EP G-3, "Emergency Notification of Off-Site Agencies." The inspector reviewed a sample of 8 emergency responder qualification and training records and a sample of 10 drill participation records. The inspector reviewed alert and notification system testing procedures, maintenance records, and a 100 percent sample of siren test records.

b. Findings

The inspector observed one instance where a DEP performance indicator opportunity for notification accuracy and timeliness was incorrectly judged as a successful opportunity. During an operator continuing training simulator session, the scenario conditions required an Alert declaration and changed approximately 3 minutes later to require a Site Area Emergency declaration. The first emergency declaration was made as a Site Area Emergency approximately 17 minutes after conditions required the Alert declaration. This performance was critiqued thoroughly by the PG&E operations and emergency preparedness staff, and it was concluded to be acceptable performance due to the rapidly changing plant conditions. The DEP performance indicator for event classification was also evaluated as successful. The inspectors discussed this evaluation with the emergency preparedness staff and concluded that the classification opportunity should have been evaluated as a missed opportunity. NEI 99-02 requires that the classification opportunity be evaluated as unsuccessful if the declaration of the emergency classification is not made within 15 minutes of the time that conditions that require the declaration are available to the decision maker. Based on that criteria in this case, the performance indicator would be successful if an Alert or Site Area Emergency had been declared within 15 minutes of the time that conditions for an Alert were available. This change would not have affected the reported performance indicator color.

The inspector also noted that Procedures EP G-2 and EP G-3 discussed the role of the unaffected unit shift foreman as the control room communicator with responsibilities including gathering information and completing the offsite notification form and performing the communications to the offsite agencies. This would require that the unit shift foremen be tracked in the ERO performance indicator as control room communicators, in addition to the Shift Manager, who also performs those functions. PG&E only tracks the shift manager for the ERO performance indicator, since, in practice, the shift manager is the only individual who completes the notification form. PG&E entered the procedure inconsistency in the corrective action process as AR A0594284 to change Procedures EP G-2 and EP G-3 to reflect the site practice that only the shift manager performs the communicator functions of filling out the notification forms.

4OA2 Problem Identification and Resolution (71152)

.1 Emergency Planning Annual Sample Review

a. Inspection Scope

The inspector selected 27 action requests for detailed review. The entries were reviewed to ensure that the full extent of the issues was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspector reviewed seven assessment reports and corrective actions resulting from those assessments. The inspector evaluated corrective actions against the requirements of Procedure OM7.ID1, “Problem Identification and Resolution-Action Requests,” and Emergency Planning Guide EPG01, “Problem Identification.”

b. Findings

No findings of significance were identified.

.2 Packing Gland Follower Failure (Unit 1)

a. Inspection Scope

The inspectors reviewed the licensee response and actions that led to a packing gland follower failure and leak from Valve SI-1-8890. The inspectors reviewed operator actions on December 3, 2003, upon discovery of a significant leak from the packing gland of Valve SI-1-8890 (as discussed in AR A0595692). The inspectors also evaluated PG&E operating experience reviews dating to December 2000 that discussed the potential for packing gland follower failures in Rockwell-Edwards valves (AR A0522770).

b. Findings

Introduction. A self-revealing Green noncited violation was identified for the failure to adequately evaluate operating experience related to failed packing gland followers for Rockwell-Edwards valves. This was a violation of 10 CFR Part 50, Appendix B, Criterion XVI, for failure to identify and correct a condition adverse to quality.

Description. On December 3, 2003, at 10:24 a.m., inservice inspection engineers identified that Unit 1 Valve SI-1-8890A (the hot leg injection equalizing valve) had a 30 drop per minute leak rate from the packing gland. The inservice inspection engineer initiated AR A0595692 to enter this item into the corrective action program. This information was reported to the control room but not immediately acted upon. The engineers reported this information to the system and component engineers, who inspected the valve. The system engineer found that the packing gland follower flange for Valve SI-1-8890 had split in two and that the valve leakage was excessive for the low pressure condition with no pumps running. The system engineer reported this additional information to the control room and stated that the packing would be rejected from the valve and an excessive amount of leakage (on the order of several gallons per minute) would result if the safety injection pumps were running.

The shift foreman evaluated this condition and, due to the cross-connected alignment of the safety injection system, declared both trains of safety injection inoperable at 1:10 p.m. This entry into Technical Specification 3.0.3 required PG&E to take action to shut down Unit 1 within 1 hour and go to Hot Standby within the following 6 hours. At 1:18 p.m., operators closed Valve SI-1-8821A, the cross-connect valve between the two safety injection trains. Thus, safety injection Pump 1-2 was isolated from the leak and failed packing follower of Valve SI-1-8890A, and the shift foreman exited Technical Specification 3.0.3. The shift foreman entered the 72-hour limiting condition for operation for inoperable safety injection Pump 1-2. On December 4, 2003, the mechanics repaired and retested Valve SI-1-8890A and declared safety injection Pump 1-2 operable.

Valve SI-1-8890A was a one-inch manual globe valve purchased from the Rockwell-Edwards company. Operating experience Letter OE11685 issued in December 2000 discussed a failure of a Rockwell-Edwards 1-inch manual globe valve at another facility that resulted in a reactor trip. The valve failure at the other facility also resulted from the splitting in two of the packing gland follower flange, ejecting the packing gland follower, causing excessive packing leakage. The other licensee analyzed this failure and determined that the packing gland follower flange was made from 410 stainless steel, a material with a very high hardness that was very susceptible to intergranular stress corrosion cracking.

PG&E analyzed operating experience Letter OE11685 and determined that this operating experience was applicable to Diablo Canyon. PG&E initiated AR A0522770 to evaluate the impact of this industry experience on Diablo Canyon and take corrective actions as deemed necessary. The engineers noted that Diablo Canyon had 225 Rockwell-Edwards valves installed, 113 for Unit 1 and 112 for Unit 2. PG&E staff determined that, since the operating experience letter described an event in which the packing gland follower flange failure resulted in a reactor trip, the evaluation for Diablo Canyon need only encompass valves whose failure could cause a reactor trip. The engineers did not consider taking action for valves in emergency core cooling systems or valves that served as containment isolation valves, nor did the evaluation examine the impact on plant risk. Thus, PG&E identified that only 12 valves at Diablo Canyon needed to be repaired or back seated to meet the intent of operating experience Letter OE11685.

The inspectors evaluated PG&E's review in AR A0522770 and determined that this review of industry experience was insufficient, lacked thoroughness, and did not meet the intent of determining the impact of the operating experience on plant safety. The inspectors determined that this was a missed opportunity to identify and correct this condition at Diablo Canyon, a violation of 10 CFR Part 50, Appendix B, Criterion XVI. PG&E initiated AR A0595762 to enter this item into the corrective action program and reevaluate operating experience OE 11685. PG&E then prioritized and took action to either backseat, repair, or use a strongback on risk important valves.

<u>Analysis</u>. The inspectors determined that PG&E's failure to promptly identify and correct a condition adverse to quality, which resulted in a packing gland follower failure and leak from Valve SI-1-8890, was a performance deficiency. The finding impacts the mitigating system cornerstone through degraded overall availability of the components within a system used to assess and respond to initiating events to prevent undesirable consequences and is greater than minor because the finding would become a more significant safety concern if the leaky valve condition was left uncorrected. The amount

of leakage from the valve would be significantly greater than a 30 drop per minute leak rate, if the safety injection pumps were fully running in the hot leg injection mode. The Valve SI-1-8890A leak rate is bounded by a RHR pump seal failure. Although PG&E declared both trains of the safety injection system to be inoperable and entered Technical Specification 3.0.3 upon discovery of the condition, the safety injection system was considered to be operable but degraded because both safety injection system trains would be available to provide adequate flow when a demand occurs. Using the SDP Phase 1 worksheet in IMC 0609, Appendix A, the finding was determined to be of very low safety significance, since there is no loss of an actual safety function, no loss of a safety-related train for greater than the Technical Specification allowed outage time, and the finding is not potentially risk significant due to a seismic, fire flooding, or severe weather initiating event.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, states, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, in December 2000, PG&E failed to identify and correct the population of Rockwell-Edwards valves in safety-related and risk-significant systems that were susceptible to intergranular stress corrosion cracking and failure of the packing gland follower flange. As a result, on December 3, 2003, the packing gland follower flange for Valve SI-1-8890A on the hot leg injection line failed, due to intergranular stress corrosion cracking. Because the failure to promptly identify and correct Rockwell-Edwards valves that were susceptible to the hardened packing gland follower flanges is of very low safety significance and has been entered into the corrective action program as AR A0595762, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy:
NCV 50-275/03-08-05, Failure to promptly identify and correct Rockwell-Edwards valves susceptible to packing gland follower flange failures.

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

Section 1RO5.2 of this report describes a PI&R crosscutting aspect for corrective actions not being promptly implemented, related to the Fire Protection Program, following concerns with implementation of the operations responder position.

4OA3 Event Followup (71153)

.1 (Closed) Licensee Event Report 50-275/03-001-00: Technical Specification 3.8.1, Action B.1, Not Met Due to Personnel Error.

On October 9, 2003, a unit shift foreman recognized that operators failed to perform an offsite power circuit check when an emergency diesel generator was declared inoperable for exhaust stack slide bearing replacement. Technical Specification 3.8.1, “AC Sources – Operating,” Action B.1, requires that an offsite power circuit check be performed within one hour upon declaring an emergency diesel generator inoperable. PG&E determined that the cause of Technical Specification violation was a failure of the Unit 1 shift foreman to recognize the need to perform the offsite power circuit check.

The operators subsequently determined that two independent circuits between the off-site transmission network and the on-site distribution system were operable. Corrective actions include briefing all operating crews on effective control room communication and modifying the Technical Specification tracking module to require a sign-off that any required conditional surveillances are being implemented upon declaring equipment inoperable. No new findings were identified in the inspector's review. The finding constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. PG&E documented the problem in Nonconformance Report N0002172. This licensee event report is closed.

40A4 Crosscutting Aspects of Findings

Section 1R12 of the report describes a human performance crosscutting issue where maintenance personnel performed improper maintenance practices on Valve FW-1-FCV-437.

Section 1R19 of the report describes a human performance crosscutting issue where personnel inappropriately assembled the core exit thermocouples and subsequently failed to recognize for an extended period the thermocouple readings were not consistent with the core design.

40A5 Other

Evaluation of Diablo Canyon Safety Condition in Light of Financial Conditions

a. Inspection Scope

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

b. Findings

No findings of significance were identified.

40A6 Management Meetings

Exit Meeting Summary

The resident inspection results were presented on January 8, 2004, to Mr. David H. Oatley, Vice President and General Manager, 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 reviewed by the inspectors and left with PG&E at the end of the inspection.

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. Hays, Director, Maintenance Services
S. Ketelsen, Manager, Regulatory Services
T. King, Manager, Learning Services
M. Lemke, Manager, Emergency Preparedness
D. Oatley, Vice President and General Manager, Diablo Canyon
P. Roller, Director, Operations Services
J. Tompkins, Director, Site Services
L. Womack, Vice President Nuclear Services

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

50-275; 323/03-08-01	NCV	Failure to Establish and Implement Fire Program Procedural Changes for Operations Responders in Support of the Fire Brigade (Section 1R05.2)
50-275/03-08-02	NCV	Failure to Adequately Monitor Auxiliary Feedwater System According to 10 CFR 50.65(a)(2) (Section 1R12)
50-275/03-08-03	NCV	Failure to Provide Adequate Technical Bases for Core Exit Thermocouple Radial Temperature Measurement (Section 1R19)
50-323/03-08-04	FIN	Failure to Maintain Job Dose ALARA (Section 2OS2)
50-275;323/03-08-05	NCV	Failure to promptly identify and correct Rockwell-Edwards valves susceptible to packing gland follower flange failures (Section 4OA2.2)

Closed

50-275/03-001-00	LER	Technical Specification 3.8.1, Action B.1, Not Met Due to Personnel Error (Section 4OA3.1)

A-1 Attachment

LIST OF DOCUMENTS REVIEWED

Section 1R04: Complete System Walkdown

Action Requests

A0546025	A0565358	A0575523	A0585572
A0546040	A0565369	A0575525	A0586410
A0547457	A0566251	A0575726	A0586489
A0549020	A0566911	A0577029	A0588816
A0549960	A0569438	A0577556	A0589346
A0552544	A0570386	A0577805	A0589783
A0553380	A0571874	A0579085	A0593236
A0558563	A0572253	A0583139	A0593493
A0560487	A0573626	A0584455	A0593495
A0560628	A0574099	A0584487	
A0564139	A0575499	A0584685	
A0564837	A0575511	A0584839	

Section 1R05: Fire Protection

Licensing Basis Impact Evaluation Screen 1998-146, “FSAR Section 9.5H - Revision 12"
Licensing Basis Impact Evaluation Screen 2003-004, “FSAR Section 9.5H - Revision 14"

Section 1R06: Flood Protection

Action Requests

A0565300	A0568332	A0572819	A0581849
A0566672	A0571777	A0573248	A0592884
A0566894	A0572772	A0573508	

Work Orders

R0239570

Section 1R19: Post-Maintenance Testing

Action Requests

A0528665
A0538684
A0590156

Work Orders

C0176158
C0176579

Other Documents

Diablo Canyon Units 1 & 2, Technical Specification Bases, B3.3.3, “PAM Instrumentation,” Revision 2
Procedure STP R-27A, “Monthly Incore Thermocouple Evaluation,” Revisions 6 & 8
Troubleshooting Log for A0590156
NRC Safety Evaluation Report SSER 31, “Diablo Canyon – SSER 31: Staff Evaluation of Miscellaneous Matters for Unit 2 (Board Notification No. 85-051),” May 2, 1985

Section 1EP2: Alert Notification System Testing

DCPP EWS Operating System - Project Proposal, November 2000
FEMA Region IX letters to PG&E, February 22 and May 11, 2001
PGE letter to FEMA Region IX, April 24, 2001
FEMA Early Warning System Design Report, December 1984

Section 1EP3: Emergency Response Organization Augmentation Testing

Rapid response drill reports from January 22, May 17, and September 9, 2003

Section 1EP4: Emergency Action Level and Emergency Plan Changes

OM10.ID2, “Emergency Plan Revision and Review”

Section 1EP5: Correction of Emergency Preparedness Weaknesses and Deficiencies

Action Requests: 0547774, 0550693, 0551200, 0554959, 0555070, 0558465, 0558491, 0558493, 0559139, 0566575, 0567256, 0567309, 0570531, 0572729, 0579860, 0580113, 0580122, 0580152, 0580154, 0582237, 0583140, 0583142, 0583391, 0584767, 0587734, 0589170, 0592987

Section 4OA2: Problem Identification and Resolution

Self-Assessment for NRC Information Notice 2002-14, October 3, 2003
Self-Assessment, Bravo Team Graded Exercise, October 23, 2002
Self-Assessment, Charlie Team Drill, May 28, 2003
Self-Assessment, Alpha Team Drill, July 17, 2003

Section 2OS2: ALARA Planning and Controls

Procedures:

AD2.ID1	Procedure Use and Adherence, Revision 11
RP1	Radiation Protection, Revision 3
RP1.DC4	Radiological Hot Spot Identification and Control Program, Revision 1A
RP1.ID1	Requirements For The ALARA Program, Revision 2B
RP1.ID2	Use and Control of Temporary Radiation Shielding, Revision 5B
RP1.ID10	Embryo/Fetus Protection Program, Revision 2A
RCP D-205	Performing ALARA Reviews, Revision 13
RCP D-240	Radiological Posting, Revision 12A

Temporary Shielding Packages:
91-163
98-059

Hot Spot Packages:
113
116

Action Requests:
ETR-V0042728, AR- A0536032, A0571273, A0572734, A0572911, A0575867, A0577951, A0578496, A0579604, A0581774, A0585060, A0589289, A0591813, and A0592291

LIST OF ACRONYMS

ADAMS	agency document access and management system
AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
AR	action request
DEG	diesel engine generator
CFR	*Code of Federal Regulations*
DEP	drill and exercise performance
EOF	Emergency Operations Facility
ERO	emergency response organization
FEMA	Federal Emergency Management Agency
FIN	finding
FSAR	Final Safety Analysis Report
IMC	Inspection Manual Chapter
LER	licensee event report
NCR	nonconformance report
NCV	noncited violation
NEI	Nuclear Energy Institute
NOUE	notification of unusual event
NRC	Nuclear Regulatory Commission
PARS	publicly available records system
PG&E	Pacific Gas and Electric Company
RCP	reactor coolant pump
RHR	residual heat removal
RI	resident inspector
RWP	radiation work permit
SDP	significance determination process
SRI	senior resident inspector
URI	unresolved item