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

April 29, 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, California 93424

SUBJECT: DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000275/2004002 AND 05000323/2004002

Dear Mr. Rueger:

On March 31, 2004, the U.S. Nuclear Regulatory Commission completed an inspection at your Diablo Canyon Power Plant, Units 1 and 2 facility. The enclosed integrated report documents the inspection findings that were discussed on April 8, 2004, with Mr. James R. Becker and members of your staff.

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

There were three NRC-identified findings and one self-revealing finding of very low safety significance (Green) identified in this report. These findings involved violations of NRC requirements. However, because of their very low risk significance and because they were 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.

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.

During the period of December 22, 2003, through March 31, 2004, the NRC has been conducting event followup inspections at the Diablo Canyon Power 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 DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000275/2003008 AND 05000323/2003008, Section 1R14 (ADAMS Accession ML040300257). The results of the inspection conducted January 1-9, 2004, (referred to as Phase 2 of the event followup inspections) and the additional onsite inspections performed during the Unit 1 refueling outage, (referred to as Phase 3 of the event followup inspections) are documented in this inspection report (Section 1R14.1).

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. The Phase 3 activities included additional planned inspections, including the visual inspections in Unit 1 containment that were performed during the March 2004 refueling outage and further review of your Special Report, submitted to the NRC on January 5, 2004, and the Supplement to the Special Report dated March 29, 2004 (ADAMS Accession ML040970068).

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

Sincerely,

/RA/

William B. Jones, Chief
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Division of Reactor Projects

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

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Inspection Report 05000275/2004002
and 05000323/2004002
w/attachment: Supplemental Information

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-275, 50-323
Licenses:	DPR-80, DPR-82
Report:	05000275/2004002 05000323/2004002
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:	January 1 through March 31, 2004
Inspectors:	D. L. Proulx, Senior Resident Inspector T. W. Jackson, Resident Inspector S. M. Wong, Risk Analyst J. I. Tapia, Senior Reactor Inspector
Approved By:	W. B. Jones, Chief, Projects Branch E Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000275/2004-002, 05000323/2004-002; 01/01/04 - 03/31/04; Diablo Canyon Power Plant Units 1 and 2; Equipment Alignments, Operator Performance During Non-Routine Evolutions and Events, and Operator Workarounds.

This report covered a 13-week period of inspection by resident inspectors, a risk analyst and a senior reactor inspector. The NRC identified four Green noncited violations. 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. A noncited violation of 10 CFR Part 50, Appendix B, Criterion III, was identified for the failure to translate the diesel emergency generator fuel oil usage design basis assumptions into procedures. Specifically, Calculation M-786 provided the basis for the Technical Specification minimum required volume of fuel oil in the fuel oil storage tanks to meet a 7 day fuel oil supply following a loss of offsite power for both units. The minimum volume was based on each unit operating only the minimum safety-related loads to achieve and maintain safe shutdown. However, the diesel engine generator minimum safety-related loads were not translated into procedures, nor were any instructions provided to alert operators to take actions to conserve fuel oil. With all six diesel engine generators running fully loaded there is insufficient fuel oil in the fuel oil storage tanks for 7 days of operation.

  This issue affects the mitigating systems cornerstone objective to ensure the availability of onsite emergency AC power during the entire period described in the design basis. This issue is more than minor because it could have an actual impact on the ability of the diesel engine generators to mitigate a long-term loss of offsite power event. Using the Phase 1 significance determination process the inspectors determined that the issue was of very low safety-significance (Green) because the finding does not represent an actual loss of a safety system or a single train and did not meet the criteria for being risk significant because of an external event (Section 1R04.4).

- Green. A noncited violation with two examples was identified by the inspectors for the failure to assure activities affecting quality shall be accomplished in accordance with documented instructions, procedures, or drawings, as required by 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, Pacific Gas and Electric failed to provide adequate procedures for preventive maintenance and operation of Limitorque motor-operated valves. The inadequate procedures resulted in the degraded operation of three Limitorque motor-operated valves in the auxiliary saltwater system during quarterly valve surveillance activities.

The performance deficiency associated with the finding is the failure to provide adequate instructions for preventive maintenance and operation of Limitorque motor-operated valves. The preventive maintenance aspect was evident with the Limitorque valves located in a moist environment. This finding impacted the mitigating systems cornerstone for the reliability of the auxiliary saltwater system that affects both shutdown and operating equipment. The finding is greater than minor because the finding would become a more significant safety concern if the problem was left uncorrected. Specifically, the problems of undiscovered rust formation on the valve declutch lever and the out-of-adjustment tripper fingers would continue to affect manual operation of the Limitorque valves and the ability to re-engage the motor operator. Using the SDP Phase 1 Worksheet in Inspection Manual Chapter 0609, the inspectors determined that this finding is of very low safety significance. Although operation of the three ASW valves were degraded, the three motor-operated valves were available to perform their intended safety functions. The finding did not result in a loss of safety function or screen as potentially risk significant from the consideration of external event impacts (Section 1R04.5).

- Green. A noncited violation of Technical Specification 5.4.1.a. was identified by the inspectors for the failure to adequately control the storage of temporary equipment that has a potential for seismically-induced system interaction with safety systems. Specifically, on March 18 and then on March 31, the inspectors identified an instance were transient equipment was stored in close proximity to safety systems and considered to be potential seismically-induced system interactions. On March 18 Pacific Gas and Electric identified two other instances where temporary equipment could cause a seismically-induce system interaction with safety systems. In each case the equipment was determined not to impact the functionality of the safety systems in the event of an earthquake.

  The finding impacted the mitigating systems cornerstone for protection against external hazards. The issue was determined to be more than minor when compared to Example 4.a of Inspection Manual Chapter 0612, Appendix E. Similar to the example, the inspectors and Pacific Gas and Electric found four examples on the auxiliary building 140 ft. elevation where temporary equipment was stored contrary to procedures to protect safety-related systems from seismic impact. Using the Significance Determination Process Phase I worksheet in Inspection Manual Chapter 0609, Appendix A, the finding is of very low safety significance since it did not screen as potentially risk significant due to a seismic event. Specifically, the inspectors determined that the finding did not involve the loss or degradation of equipment or function specifically designed to mitigate a seismic event and it does not involve the total loss of any safety function with respect to a seismic event (Section 1R14.4).

- Green. A noncited violation was identified by the inspectors for the failure to promptly address operability of Diesel Engine Generator 1-2 in accordance with 10 CFR Part 50, Appendix B, Criterion XVI. Specifically, Pacific Gas and Electric identified a leaking valve that could cause the loss of prime to the fuel oil booster pump, but failed to adequately address the operability of Diesel Engine Generator 1-2 with respect to the leak. The failure resulted in an additional challenge to operators approximately two months later.

  The finding impacted the mitigating systems cornerstone for reliability of an emergency AC power source. The issue was more than minor since it affected the configuration control and procedure quality attributes for the mitigating system cornerstone. Using the significance determination process Phase 1 worksheet in Inspection Manual Chapter 0609, the inspectors determined that the deficiency was confirmed not to result in a loss of function per Generic Letter 91-18. The finding was determined to be of very low safety significance (Section 1R16).

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Diablo Canyon Unit 1 began this inspection period at 100 percent power. On January 15, 2004, operators reduced reactor power to approximately 50 percent power to inspect the main condenser for saltwater in-leakage. After condenser tube inspections and repairs were completed, operators began increasing Unit 1 reactor power on January 17 and reached 100 percent power on January 18. On February 23 operators reduced Unit 1 power level to 80 percent due to high inlet stator pressure on the stator coil cooling water system. By reducing reactor power to 80 percent, operators alleviated concerns with maintaining main generator hydrogen purity. On February 25 operators further reduced reactor power to 24 percent due to a high Pacific Ocean swell warning. Operators increased reactor power to 85 percent on February 27 once the swell warning had been terminated. Unit 1 remained at 85 percent power until the beginning of Refueling Outage 1R12.

On March 22 operators commenced a reactor shutdown for Refueling Outage 1R12 and entered Mode 3 (Hot Standby). Operators initiated a plant cooldown and entered Mode 4 (Hot Shutdown) on March 22 and Mode 5 (Cold Shutdown) on March 23. On March 27 Unit 1 entered Mode 6 (Refueling) when maintenance personnel de-tensioned the reactor vessel head. Operators commenced core offload on March 30 and completed core offload on March 31. The Unit 1 reactor remained de-fueled at the completion of the inspection period.

Diablo Canyon Unit 2 began this inspection period at 100 percent power. On February 25 operators reduced reactor power to 24 percent power due to high Pacific Ocean swells. Operators increased reactor power to 100 percent on February 27 once the swell warning had been terminated. Operators reduced reactor power to 85 percent on March 27 to perform main turbine valve testing. Upon completion of testing, operators returned reactor power to 100 percent 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 Auxiliary Feedwater (AFW) System

a. Inspection Scope

On January 7, 2004, while AFW Pump 2-1 was in a maintenance outage window, the inspectors performed a partial system walkdown of Unit 2 AFW Pumps 2-2 and 2-3.

The inspectors observed AFW system valve alignment, the availability of electrical power and cooling water, labeling, lubrication, ventilation, structural support, and material condition. The inspectors used Drawing 107703, “Feedwater,” Sheet 3, Revision 41, and Attachment 9.2 of Procedure OP D-1:II, “Auxiliary Feedwater System - Alignment Verification Checklist,” Revision 24, during the inspection.

b. Findings

No findings of significance.

.2 Unit 1 Residual Heat Removal (RHR) System

a. Inspection Scope

On February 11, 2004, while RHR Pump 1-2 was in a maintenance outage window, the inspectors performed a partial system walkdown of Unit 1 RHR Pump 1-1. The inspectors observed valve alignment, the availability of electrical power and cooling water, labeling, lubrication, ventilation, structural support, and material condition. The inspectors used Drawing 106710, “Residual Heat Removal,” Sheet 2, Revision 33, and Procedure OP B-2:I, “RHR System Alignment Verification for Plant Startup,” Revision 16, during the inspection.

b. Findings

No findings of significance were identified.

.3 Unit 1 Component Cooling Water (CCW) System

a. Inspection Scope

On February 17, 2004, while CCW Pump 1-2 was in a maintenance outage window, the inspectors performed a partial system walkdown of Unit 1 CCW Pumps 1-1 and 1-3. The inspectors observed valve alignment, the availability of electrical power and cooling water, labeling, lubrication, ventilation, structural support, and material condition. The inspectors used the following documents during the inspection:

- Drawing 106714, “Component Cooling Water,”
  - Sheet 2, Revision 45
  - Sheet 3, Revision 49
  - Sheet 4, Revision 49

- Procedure OP F-2:VI, “CCW System Alignment Verification for Plant Startup,” Revision 27

- Plant Engineering Procedure PEP-EN-1, "Plant Accident Mitigation Diagnostic Aids and Guidelines,” Revision 13

b. Findings

No findings of significance were identified.

.4 Diesel Fuel Oil Transfer and Storage System (Units 1 and 2)

a. Inspection Scope

From February 9-13, 2004, the inspectors performed a partial system walkdown of the diesel engine generator (DEG) fuel oil transfer and storage system, including design basis calculations for the diesel fuel oil storage tank capacity. The inspectors used Procedures OP AP-26, "Loss of Offsite Power," Revision 7B, and OP J-6C:I, "Diesel Fuel Oil Transfer System – Make Available and Place in Service," Revision 7A and Calculation M-786 "Emergency Diesel Generator Fuel Oil Storage," Revision 13, to support the inspection.

b. Findings

Introduction. A Green noncited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion III, was identified for the failure to translate the DEG fuel oil usage design basis assumptions into procedures. Specifically, Calculation M-786 provided the basis for the Technical Specification minimum required volume of fuel oil in the fuel oil storage tanks to meet a 7 day fuel oil supply following a loss of offsite power for both units. The minimum volume was based on each unit operating only the minimum safety-related loads to achieve and maintain safe shutdown. However, the DEG minimum safety-related loads were not translated into procedures, nor were any instructions provided to alert operators to take actions to conserve fuel oil. With all six DEGs running fully loaded there in insufficient fuel oil is the fuel oil storage tanks for 7 days of operation.

Description. Diablo Canyon is licensed for fuel oil storage capacity of 65,000 gallons. The basis of this capacity is a loss of offsite power and a loss of coolant accident in one operating unit, then achieving and maintaining safe shutdown in both units for 7 days. Calculation M-786 assumed that each unit would only operate the minimum safety-related loads necessary to achieve these conditions for the duration of the 7 days. In the license amendment request justifying this capacity, Pacific Gas and Electric Company (PG&E) stated that these loading conditions would not be directly cited in procedures to give operators flexibility. However, neither Procedure OP AP-26, nor PEP-EN-1 provided any direction to operators to take action to minimize fuel consumption for a long term loss of offsite power requiring several days of diesel fuel oil usage. The inspectors noted that if all six diesel generators on both units ran continuously fully loaded, the fuel oil would only last two days. Without directions to take action to minimize loads and conserve fuel, PG&E could not meet the 7 day design basis and may run out of fuel during a prolonged loss of offsite power event.

Analysis. This issue affects the mitigating systems cornerstone objective to ensure the availability of onsite emergency AC power during the entire period described in the design basis. This issue is more than minor because it could have an actual impact on the ability of the DEGs to mitigate a long-term loss of offsite power event. Using the Phase 1 significance determination process (SDP) the inspectors determined that the issue was of very low safety-significance (Green) because the finding does not represent an actual loss of a safety system or a single train and did not meet the criteria for being risk significant because of an external event. PG&E also identified an alternate means to obtain additional fuel oil from offsite sources in an expeditious manner.

Enforcement. 10 CFR Part 50, Appendix B, Criterion III states, in part, that the design bases must be translated into instructions, procedures and drawings. The DEG load assumptions in Calculation M-786, "Diesel Generator Fuel Oil Storage," Revision 13, which establishes the volume of diesel fuel oil needed for 7 days following a loss of offsite power and a loss of coolant accident on one unit is based on PG&E's assumption that only the minimum loads necessary to achieve and maintain safe shutdown are loaded on the diesels. Contrary to 10 CFR Part 50, Appendix B, Criterion III, the DEG load assumptions developed in Calculation M-786, were not translated into instructions, procedures, or drawings. Neither Procedures OP AP-26, PEP-EN-1, nor any other instruction or procedure was found to contain direction for the operators to take action to conserve fuel (i.e. disconnecting unnecessary loads) to mitigate a long term loss of offsite power. Because this violation was of very low safety significance and has been entered into the corrective action program as Action Request (AR) A0602053, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275; 323/04-02-01, Failure to Translate DEG Fuel Oil Volume Design Basis Assumptions into Implementing Procedures.

Complete System Walkdown

.5 Unit 1 & 2 Auxiliary Saltwater (ASW) Systems

a. Inspection Scope

On February 20, 2004, the inspectors performed a complete system walkdown of Units 1 and 2 ASW systems. The inspectors observed pump and valve alignments, the availability of electrical power, labeling, lubrication, ventilation, structural support, and material condition. The inspectors also reviewed past and present deficiencies. The inspectors used the following documents during the inspection:

- Procedure E-5:I, "Auxiliary Saltwater System – Alignment Verification Checklist," Revision 26A
- Procedure MP E-53.10A, "Preventive Maintenance of Limitorque Motor Operators," Revision 26

- Procedure STP V-3F1, "Exercising Valve FCV-495, ASW Pump 2 Crosstie Valve," Revision 20

- Procedure OP O-9, “Manual Seating of Motor Operated Valves,” Revision 15

- Drawing 106717, “Saltwater,”
  - Sheet 7, Revision 129
  - Sheet 7A, Revision 127

b. Findings

Introduction. A Green, self-revealing, NCV was identified for the failure to assure activities affecting quality were accomplished in accordance with documented instructions, procedures, or drawings, as required by 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings. “ Specifically, PG&E failed to provide adequate procedures for preventive maintenance and operation of Limitorque motor-operated valves located in a moist environment. The inadequate procedures resulted in the degraded operation of three Limitorque motor-operated valves in the ASW system during quarterly valve surveillance activities.

Description. On October 16, 2003, the closing torque of Valve SW-2-FCV-495 was found to be approaching the valve weak link limit. The cause of the high closing torque was due to the buildup of marine deposits on the disk seating surface. The valve was replaced. Maintenance personnel used Procedure MP E-53.10A, “Preventive Maintenance of Limitorque Motor Operators,” Revision 26, to verify the adequacy of maintenance and testing of Valve SW-2-FCV-495 following replacement of the valve.

On January 21, 2004, Valve SW-2-FCV-495 failed to stroke close electrically and its actuator motor tripped on thermal overload following the performance of Procedure STP V-3F1, “Exercising Valve FCV-495, ASW Pump 2 Crosstie Valve,” Revision 20. The thermal overload occurred after Valve SW-2-FCV-495 was declutched and manually stroked in the close position after 5 turns. Visual observation of Valve SW-2-FCV-495 indicated that the valve was in mid-travel between the open and closed position. Maintenance personnel found that excessive rust formation on the valve declutch lever prevented the valve actuator from fully switching from manual to its electric operation. The inspectors reviewed the October 16, 2003, records of postmaintenance testing activities for Valve SW-2-FCV-495. Based on the review, the inspectors determined that incipient rust formation occurred on the valve declutch lever and could have been discovered during postmaintenance testing activities on October 16, 2003. The inspectors noted that the preventive maintenance Procedure MP E-53.10A did not provide instructions to remove the declutch lever and handwheel for cleaning and inspection. Subsequently, PG&E added additional instructions to Procedure MP E-53.10A to ensure that the declutch lever and handwheel are removed for cleaning and inspection during preventive maintenance of Limitorque motor operated valves located in a moist environment.

On January 22, 2004, Valve SW-1-FCV-495 was found to require its declutch lever to be held in the engaged position for manual stroking of the valve during performance of Procedure STP V-3F1. The valve declutch lever did not stay in the "manual" position as expected while the handwheel was turned during manual operation of Valve SW-1-FCV-495. Valve SW-1-FCV-496 also experienced similar problems. The probable cause of the declutch lever failing to remain engaged when in its manual position was determined to be due to the tripper fingers being out of adjustment. PG&E personnel indicated that the tripper fingers could be out of adjustment due to the improper adjustment of the fingers when the valve was initially installed, or from improper lever manipulation during valve surveillance activities.

The inspectors reviewed Procedure MP E-53.10A and determined that the preventive maintenance procedure did not properly address manual operation of the Limitorque motor actuators, which is to depress the declutch lever and release. The lever should remain in the depressed position until the electric motor is engaged. The plant operators had been using Procedure OP O-9, "Manual Seating of Motor Operated Valves," Revision 15, for manual operation of safety-related motor-operated valves. The inspectors reviewed this procedure and determined that the procedure did not contain adequate instructions to hold the declutch lever down during a manual stroking operation of the valve. Additional instructions are now provided in Procedure OP O-9 to initiate an AR when the declutch lever does not remain depressed for manual valve operation.

Based on the examples discussed above, the inspectors concluded that inadequate preventive maintenance and operating instructions for Limitorque motor-operated valves had resulted in degraded operation of Valves SW-1-FCV-495; SW-1-FCV-496, and SW-2-FCV-495 located in the Unit 1 and Unit 2 ASW systems.

Analysis. The performance deficiency associated with the finding is the failure to provide adequate instructions for preventive maintenance and operation of Limitorque motor-operated valves. The preventive maintenance aspect was evident with the Limitorque valves located in a moist environment. This finding impacted the mitigating systems cornerstone for the reliability of the auxiliary saltwater system that affects both shutdown and operating equipment. The finding is greater than minor because the finding would become a more significant safety concern if the problem was left uncorrected. Specifically, the problems of undiscovered rust formation on the valve declutch lever and the out-of-adjustment tripper fingers would continue to affect manual operation of the Limitorque valves and the ability to re-engage the motor operator. Using the SDP Phase 1 Worksheet in Inspection Manual Chapter (IMC) 0609, the inspectors determined that this finding is of very low safety significance. Although operation of the three ASW valves were degraded, the three motor-operated valves were available to perform their intended safety functions. The finding did not result in a loss of safety function or screen as potentially risk significant from the consideration of external event impacts.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,“ states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances, and the instructions, procedures, and drawings shall include appropriate quantitative and qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to the above, the procedures for preventive maintenance and operation of Limitorque motor-operated valves did not provide adequate instructions for conducting preventive maintenance on Limitorque valves, which were located in a moist environment, as well as manual valve operation. The lack of adequate instructions resulted in degraded operation of Valves SW-1-FCV-495; SW-1-FCV-496, and SW-2-FCV-495 located in the Unit 1 and Unit 2 ASW systems on January 21 - 22, 2004. Because this failure to provide adequate instructions for the the preventive maintenance and manual operation of Limitorque valves is of very low safety significance and has been entered into the correction action program as AR A0598902, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275; 323/04-02-02, Failure to Provide Adequate Instructions for Preventive Maintenance and Operation of Limitorque Motor-Operated Valves.

1R05 Fire Protection (71111.05)

The inspectors performed eight fire protection walkdowns during this inspection period.

.1 Routine Observations

a. Inspection Scope

The inspectors performed eight 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, containment spray pump rooms
- Units 1 and 2, intake structure
- Units 1 and 2, diesel generator rooms of the turbine building
- Units 1 and 2, battery and battery charger rooms

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06)

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

.1 Internal Flood Protection

a. Inspection Scope

The inspectors reviewed the internal flood protection measures in the event of a failure of a break in a fire main in the fuel building and auxiliary building. The inspectors reviewed the FSAR and examined the condition of floor drains.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

Annual Review

a. Inspection Scope

The inspectors reviewed the inspection results of the Unit 2 component cooling water heat exchangers. The inspectors reviewed design information found in Chapter 9 of the FSAR – Update and verified the microfouling and macrofouling data obtained after performance of Procedure MA1.DC51, “Preventive Maintenance Program,” Revision 8.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

The inspectors witnessed one operator requalification exam 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 operating crew responded to two scenarios during the evaluation. The first scenario involved a seismic event followed by a small break loss-of-coolant accident and loss of all high pressure injection, which required the operators to mitigate the scenario using functional recovery procedures. The second scenario involved a steam generator tube rupture and loss of one safety bus.

The inspectors used the following procedures as guidance:

- OP AP-3, "Steam Generator Tube Rupture," Revision 5
- OP AP-17, "Loss of Charging," Revision 23
- OP AP-27, "Loss of Vital 4kV or 480V Bus," Revision 0A
- E-0, "Reactor Trip or Safety Injection,"Revision 27
- E-1, "Loss of Reactor or Secondary Coolant," Revision 19
- E-1.2, "Post LOCA [Loss of Coolant Accident] Cooldown and Depressurization," Revision 16
- FR-C.1, "Response to Inadequate Core Cooling," Revision 15
- FR-C.2, "Response to Degraded Core Cooling," Revision 13

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors performed two 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 if required, whether goal setting was recommended. Procedure MA1.ID17, “Maintenance Rule Monitoring Program,” Revision 12, was used as guidance. The inspectors reviewed the following action requests:

- A0576690, “Investigate/Repair 52VU23 Breaker”
- A0566266, “2S-45 Failed To Start,” and A0599961, “S-43 Swapped Back To S-44 Due To Unexpected Shutdown Of S-43"

b. Findings

No findings of significance were identified.

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

The inspectors performed six 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 2, troubleshooting pressurizer relief tank pressure increase by closing power operated relief block Valve RCS-2-8000C, on January 5 and 6
- Unit 1, maintenance outage windows for control room ventilation system dampers VAC-1-MOD-2/2A and VAC-1-MOD-3/3A, Residual Heat Removal Pump 1-2, and auxiliary building ventilation system exhaust fan E-2, on February 11
- Unit 1, maintenance outage windows for CCW Pump 1-2 and Battery Charger 1-2, on February 17
- Unit 1, maintenance outage windows for RHR Pump 1-1 and Battery Charger 1-2 calibration of main feedwater Pump 1-1 lube oil cooler outlet Switch TS-17, and change-out of electro-hydraulic filters for the main turbine on February 19
- Unit 2, maintenance outage window for Auxiliary Feedwater Pump 2-3 and severe Pacific storm, on February 25

b. Findings

No findings of significance were identified.

.2 Emergent Work

a. Inspection Scope

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

- Unit 2, DEG 2-2 air start motor solenoid Valve SV-278 air leak (AR A0600322 and Work Order C0186894)

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

The inspectors evaluated operator performance for four samples of nonroutine evolutions or events.

.1 Followup to San Simeon Earthquake

a. Inspection Scope

Background on Earthquake

On December 22, 2003, at 11:16 a.m. PST, a 6.5 magnitude earthquake occurred 35 miles NNW of Diablo Canyon Power Plant at a depth of about 4 miles. The epicenter of the earthquake was located 6 miles NE of San Simeon, California. Based on the elastic waves that radiated from the source, the earthquake was a result of reverse faulting between the Oceanic and Nacimiento faults in the Santa Lucia mountains, north of the town of Cambria. Reverse faulting occurs when adjacent crustal blocks are thrust together, one riding over the other. The reverse faulting that resulted in this earthquake was caused by the release of compressive stress that was generated by the motion of crustal blocks within the overall strike-slip fault zone. The tectonics of coastal Central California are dominated by the northwestwards motion of the Pacific plate with respect to the North American plate. The majority of the relative plate motion is accommodated by slip on major strike-slip faults, such as the San Andreas fault, situated about 37.3 miles NE of the epicenter. However, reverse fault earthquakes are not uncommon in this area due to the relatively small compression component of the overall differential motion between the plates. Other central California seismic events of nearly the same size, which have had this type of reverse motion, include the 1983 Coalinga (magnitude 6.4), and 1985 Kettleman Hills (magnitude 5.9) earthquakes. In November 1952, the Bryson earthquake (magnitude 6.0) occurred in the same general area of the December 22, 2003, earthquake.

The resultant ground acceleration at Diablo Canyon Power Plant was measured as 0.041g horizontal and 0.036g vertical. These values were measured by a sensor on the top of the Unit 1 containment base and were sufficient to activate the seismic system analog and digital recorders. Subsequent review of the seismic data disclosed that the frequency response spectra peaked at 3 to 4 Hz for all three components of motion. This was typical and expected for foundation conditions at Diablo Canyon Power Plant. The seismic design criteria for Diablo Canyon Power Plant are substantially higher than the recorded values. The original Design Earthquake values are 0.20g horizontal and 0.133g vertical. These design criteria define the ground motion for which those features necessary for continued operation without undue risk would remain functional. A Double Design Earthquake with values 0.40g horizontal and 0.267g vertical was also utilized. These criteria define the ground motion for which certain structures, systems, and components must be designed to ensure integrity of the reactor coolant system boundary and the capability to shut down the reactor and maintain it in a safe condition. The criteria also applies to structures, systems and components intended to prevent or mitigate the consequences of accidents that could result in unacceptable offsite radioactive exposures. In addition to these two original design earthquakes, Diablo Canyon Power Plant was subsequently evaluated to ensure the ability to accommodate a magnitude 7.5 earthquake originating in the Hosgri fault. The design criteria used for the Hosgri analysis were 0.75g horizontal and 0.50g vertical. Several plant modifications were implemented to provide the required margin against these design criteria.

Inspection of Structures, Systems and Components

A detailed inspection of all levels of the turbine, auxiliary, fuel handling, saltwater intake, and Unit 2 containment buildings was conducted during the period of January 5 - 9, 2004. During the inspection, particular attention was given to systems and components having the most risk significance as determined by a review of the Diablo Canyon Power Plant Probabilistic Risk Assessment. The inspection effort focused on detecting evidence of movement resulting from the seismic acceleration, as well as damage or degradation of any structure, system, or component. Inspection attributes included: misalignment of structures or components; changes in seismic gaps between buildings; movement at the juncture between a structure or component and adjacent material; repositioned components; cracks in paint, concrete, grout or masonry; movement of any kind in the surrounding environment. Components and their supports inspected included: tanks, piping, pipe restraints, snubbers, spring cans, instrumentation lines, ducting, conduits, cable trays, pumps, motors, heat exchangers, batteries, and equipment cabinets. The following items were specifically included during the inspection:

- Diesel generators
- Main steam piping
- Control room pressurization system
- Control room panels
- Cable spreading room components
- Vital batteries, chargers, and inverters
- 480v switchgear and load centers
- Component cooling water heat exchangers
- Component cooling water surge tanks
- Control rod drive motor-generator sets
- Auxiliary salt water pumps and piping
- 4kV switchgear
- Main and auxiliary transformers
- Spent fuel pools
- Boric acid storage tank
- Auxiliary feedwater pumps
- Spent fuel pool pumps
- Safety injection pumps
- Containment spray pumps
- Charging pumps
- Residual heat removal pumps
- Containment sump
- Containment fan cooler units

During the period March 30 - 31, 2004, the Unit 1 containment building was inspected. The inspection effort focused on detecting evidence of movement, as well as damage or degradation of any structure, system, or component. Inspection attributes included: misalignment of structures or components; changes in seismic gaps; movement at the juncture between a structure or component and adjacent material; repositioned components; cracks in paint, or concrete; movement of any kind in the surrounding environment. Components and their supports inspected included: piping, pipe restraints, snubbers, spring cans, instrumentation lines, ducting, conduits, cable trays, and equipment cabinets. Particular attention was given to containment spray piping and supports at the top of the containment building.

Review of Earthquake Response Procedure

The revision to Casualty Procedure M-4, “Earthquake,” was reviewed. This procedure had been revised to incorporate lessons learned from the December 22, 2003, earthquake. The revision included additional walkdown criteria for plant systems, components, scaffolding, transient equipment and outside areas.

Review of Special Report

The inspection also included a review of PG&E's Special Report 03-04, dated January 5, 2004. The report, required by the facility operating license, provides an evaluation of the magnitude of the ground motion and resultant effect on facility features important to safety. A verification of the required surveillance and calibration of seismic monitoring instruments was performed as part of this review. The adequacy of PG&E's response to the earthquake, with respect to the assessment of any damage, was also evaluated.

Review of Special Report Supplement

The inspection also included a review of the PG&E's Supplement to Special Report 03-04, dated March 29, 2004. The report was supplemented to provide the analyses of data from all actuated seismic monitoring instruments. The calculated San Simeon earthquake response spectra for the recorded responses were enveloped by the Diablo Canyon design basis response spectra for all instrument locations with the exception of the vertical response from the instrument located at the top of the Unit 1 containment building. The vertical response at this location exceeded the modeled design earthquake response by approximately 17 to 44 percent over the frequency range of 11 to 40 Hertz. A review of the seismic design basis disclosed that the effects of dynamic amplification were considered for the horizontal component of the input ground motion in the determination of the horizontal response of structures for the three design basis earthquakes: the design earthquake, the double design earthquake, and the Hosgri earthquake. The effects of dynamic amplification of the vertical component of the input ground motion was considered for the Hosgri earthquake, but not for the design earthquake or double design earthquake. The original design earthquake and double design earthquake design assumed that the structures would be rigid in the vertical direction and that, as a result, there would be insignificant amplification of vertical seismic motion. This assumption was an accepted engineering approach to seismic analysis at the time of the original design. Subsequent to the discovery of the Hosgri fault, a new analysis was performed, which recognized that the structures were not rigid in the vertical direction. This new analysis considered amplification of vertical seismic motion and resulted in modifications, however, the design earthquake and double design earthquake licensing basis criteria remained unchanged. Although the Hosgri earthquake analysis takes into account vertical amplification and was validated by the measured San Simeon earthquake, the design earthquake and double design earthquake acceptance criteria is different from that of the Hosgri earthquake analysis. Consequently, the licensee plans to perform further analyses to quantify the effect of the dynamic amplification of the vertical component of earthquake motion for the design earthquake and double design earthquake.

b. Findings

No findings of significance were identified. No system, structure or component damage nor evidence of any movement or deflection was detected, and no site ground effects were noted during exterior inspections. PG&E's physical inspections were comprehensive and effective in evaluating whether any structural damage occurred.

The inspectors determined that the seismic response data reported in the Special Report was limited to the Unit 1 containment base and a free field pit. PG&E's analysis of the earthquake's effect on the plant did not include actual measurements from all available locations. PG&E submitted a supplement report to describe the analyses of data from all actuated seismic monitoring instruments at Diablo Canyon Power Plant. This supplemental report was reviewed to compare the magnitude and frequency of the observed plant response to the design values at corresponding locations in the plant. The review disclosed that additional analysis is necessary to address the effect of vertical amplification. PG&E plans to quantify the effect of the dynamic amplification of the vertical component of earthquake motion for the design earthquake and double design earthquake. This analysis will be subsequently reviewed after receipt to verify that the acceptance criteria are satisfied.

.2 Unit 1 Curtailment Due to Stator Coil Cooling Water (SCCW) Issues

a. Inspection Scope

On February 23 operators reduced Unit 1 reactor power from 100 percent to 80 percent due to high inlet stator pressure on the SCCW system. PG&E management determined that the high stator pressure would eventually impact the operator's ability to maintain main generator hydrogen purity. By reducing reactor power level to 80 percent, the inlet stator pressure was decreased. The inspectors reviewed operator performance prior to, during, and following Unit 1 curtailment.

b. Findings

No findings of significance were identified.

.3 Units 1 and 2 Downpowers Due To High Pacific Ocean Swells

a. Inspection Scope

On February 25 and 26 the Diablo Canyon Power Plant, Units 1 and 2 experienced high Pacific Ocean swells. Prior to the arrival of the high swells, PG&E management determined that the reactors' power would be reduced to approximately 24 percent in order to reduce the risk of a reactor trip, provided a circulating water pump tripped as a result of the high swells. At 4:00 p.m. on February 25 operators began the decrease in reactor power and completed the down-power at approximately 9:30 p.m. The inspectors observed operator performance during the down-power and operator response to any high differential pressure across the traveling screens.

b. Findings

No findings of significance were identified.

.4 Magnitude 4.5 San Simeon Earthquake

a. Inspection Scope

At 3:53 p.m. PST on March 17, 2004, a magnitude 4.5 earthquake struck approximately 35 miles NNW of Diablo Canyon. This earthquake was considered an aftershock from the magnitude 6.5 earthquake that occurred on December 22, 2003, at a nearby location. The inspectors immediately informed the Region IV branch chief of the earthquake and responded to the control room to monitor plant conditions and operator actions. The inspectors observed that:

- The seismic monitoring equipment located in the control room did not register any motion from the earthquake;
- The control room operators did not feel the earthquake;
- No equipment alarms were activated as a result of the earthquake; and
- No tank levels had changed as indicated on the plant process computer.

The inspectors reviewed Procedure CP M-4, “Earthquake,” Revision 18, which required plant walkdowns and inspections if the earthquake was felt by a consensus of operators in the control room and registered at least 0.01g on the control room seismic monitor. Since the control room operators did not feel the earthquake, and the earthquake did not register on the seismic monitor, no specific walkdowns or inspections with regards to the earthquake were undertaken by PG&E staff.

On March 18 the inspectors performed a walkdown of select safety systems following the 4.5 earthquake. These systems included the refueling water storage tanks, condensate storage tanks, firewater storage tank, auxiliary feedwater pumps, emergency core cooling system pumps, component cooling water system, auxiliary saltwater pumps, diesel generators, vital electrical switchgear, and spent fuel pools. The inspectors verified the absence of structural cracks, leaks, and movement of equipment due to the earthquake.

b. Findings

Introduction. A Green NCV was identified by the inspectors for the failure to adequately control the potential for seismically-induced impact of stored, temporary equipment on safety systems, as required by Technical Specification 5.4.1.a.

Description. During the walkdown of safety systems on March 18, 2004, the inspectors observed that a large amount of temporary equipment was stored on the Auxiliary Building 140 ft. elevation in preparation for Refueling Outage 1R12. Upon inspection of the stored equipment, the inspectors identified a ladder that was stored approximately 4.5 ft. from safety-related electrical conduit. Procedure AD4.ID3, “SISIP Housekeeping Activities,” Revision 4B, stated in Table 2 that flat lying objects are considered seismically-induced system interaction (SISI) housekeeping concerns if they are located within 5 ft. of SISI targets (safety systems) and do not have a specific engineering analysis to allow storage at that location. The inspectors also identified two large toolboxes that were tied off next to the temporary hydrogen recombiner connection piping, but the piping was not considered to be a SISI target.

The inspectors notified the shift manager, who requested the assistance of civil engineering staff to assess the storage of equipment on the Auxiliary Building 140 ft. elevation. The civil engineers identified two other items that were also SISI housekeeping concerns. Two items required additional engineering review to determine if the items would have damaged safety systems in the event of a design basis earthquake. The first item was a conduit bender that was located on the northwest side of the Unit 1 atmospheric dump valve platform. PG&E’s engineering staff determined that structural steel on the platform would have prevented damage to control equipment, piping, and tubing related to the atmospheric dump valves. The second item was a set of barrels, of unknown weight and material/equipment inside, located on a pallet approximately 4 ft. from the Unit 2 auxiliary building supply fan air louvers. PG&E’s engineering staff determined that the barrels would not sufficiently block air flow or damage the louvers to impact the functionality of the auxiliary building ventilation system.

On March 31 during the review of the above mentioned items, the inspectors identified a crate approximately 4 ft. long, 4 ft. wide, and 3 ft. tall located adjacent, but not in front of an auxiliary building supply fan air louver. The crate contained metal sign stanchions. Figure 10 and other related figures in the “Seismically Induced Systems Interaction Manual,” Revision 7, did not mark the louver for which the crate was adjacent as a SISI target, but the text of the manual did identify it as a SISI target.

The inspectors confirmed that the identified SISI housekeeping concerns would not have impacted the affected safety systems in a design basis seismic event. However, Procedure AD4.ID3 stated that supervisors are responsible for ensuring assigned activities do not create potential SISI housekeeping concerns. The inspectors determined that PG&E staff did not control the creation of SISI housekeeping concerns on the Auxiliary Building 140 ft. elevation, since four items were confirmed to be SISI housekeeping concerns.

Analysis. The inspectors determined that PG&E’s failure to control seismically-induced impacts of temporarily stored equipment on safety systems, in accordance with procedures, was a performance deficiency. The finding impacted the mitigating systems cornerstone and was more than minor when compared to Example 4.a of IMC 0612, Appendix E. Similar to the example, the inspectors and PG&E staff found four examples on the Auxiliary Building 140 ft. elevation where temporary equipment was stored contrary to procedures to protect safety-related systems from seismic impact. Using the SDP Phase I worksheet in IMC 0609, Appendix A, the finding is of very low safety significance since it did not screen as potentially risk significant due to a seismic event. Specifically, the inspectors determined that the finding did not involve the loss or degradation of equipment or function specifically designed to mitigate a seismic event, and it does not involve the total loss of any safety function with respect to a seismic event.

Enforcement. Technical Specification 5.4.1.a states, in part, that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A. Regulatory Guide 1.33. , Appendix A, Item 1, to Regulatory Guide 1.33, requires that procedures be implemented for equipment control. Contrary to the above, Procedure AD4.ID3 was not followed in that four items were placed within 5 ft. of SISI targets and were considered to be SISI housekeeping concerns. Procedure AD4.ID3 also stated that supervisors were responsible for not creating SISI housekeeping concerns. Because the failure to follow Procedure AD4.ID3 was of very low safety significance and has been entered into the corrective action program as AR A0603148, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275; 323/04-02-03, Failure to Control Placement of Temporary Equipment With Regards to Potential Seismic Impact on Safety-Related Systems.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

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

- Unit 1, Centrifugal Charging Pump 1-2 recirculation check Valve CVCS-1-8479B sticks open (ARs A0586882 and A0597376)

- Unit 2, DEG 2-1 failed to reach rated voltage in less than 13 seconds (AR A0600770)

- Units 1 and 2, Ineffective vibration monitoring for DEG components (AR A0553700)

- Unit 2, Battery Charger 2-1 loose lugs (AR A601561)
- Unit 1, Operability of the turbine building superstructure (OE 2003-04)
- Unit 1, Evaluate control room ventilation with potentially degraded dampers (AR A0598418)

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds

a. Inspection Scope (71111.16)

The inspectors reviewed one sample of an operator workaround to identify any potential effect on the functionality of mitigating systems. An operator workaround is an operator action taken to compensate for a degraded or nonconforming condition that complicates the operation of plant equipment. The inspectors assessed training and knowledge needed to perform the workaround and compared the workaround to the operation of similar equipment and longstanding operational practices. The inspectors also evaluated environmental aspects for performing the operator workaround and the compatibility of the workaround to other equipment. The following operator workarounds were reviewed during this inspection period:

- Unit 1, DEG 1-2 increased loss of fuel oil level in priming tank (ARs A0595440 and A0599710)

b. Findings

Introduction. A Green NCV was identified by the inspectors for the failure to promptly address operability of DEG 1-2 in accordance with 10 CFR Part 50, Appendix B, Criterion XVI. Specifically, PG&E suspected that a leaking valve was causing the potential loss of prime to the fuel oil booster pump, but failed to adequately address the operability of DEG 1-2 with respect to the leak. The failure resulted in an additional challenge to operators approximately two months later.

Description. The fuel oil day tanks for the DEGs at the Diablo Canyon Power Plant are located underneath the DEGs. Therefore, the fuel oil priming tank for each DEG is located at a sufficient height to maintain prime to the fuel oil booster pump. The fuel oil booster pumps, in turn, supply sufficient pressure to the individual fuel oil injector pumps at each cylinder. Loss of prime to the fuel oil booster pumps would cause a slow DEG start. To maintain adequate level in the fuel oil priming tank, a magnetic priming pump is automatically run once a day (auto mode). The magnetic priming pump can also be run continuously (manual mode).

Following a test run of DEG 1-2 on November 27, 2003, operators received the fuel oil high/low level alarm in the control room and found the DEG 1-2 priming tank sight glass empty. To recover adequate fuel oil level in the priming tank, operators switched the magnetic priming pump from auto to manual mode. Without the magnetic priming pump running continuously, operators noticed that the fuel oil priming pump was losing level at approximately one inch per 20 minutes. PG&E staff postulated that debris may be holding a check valve partially open in the fuel oil day tank and allowing fuel oil to drain out of the priming tank. PG&E staff determined that the magnetic priming pump should be in manual and that DEG 1-2 was operable as long as adequate fuel oil level was maintained in the priming tank. Operators tracked the manual running mode of the magnetic priming pump through the shift foreman turnover logs for approximately two days, after which it was no longer tracked.

Following a test run of DEG 1-2 on January 23, 2004, operators received the fuel oil high/low level alarm in the control room, found the DEG 1-2 priming tank sight glass empty, and discovered that the magnetic priming pump was in the auto run mode. Subsequently, operators returned the magnetic priming pump back to manual mode to restore priming tank level. Procedure STP M-9A, “Diesel Engine Generator Routine Surveillance Test,” Revision 65, was used for the test run, and it directed operators to place the magnetic priming pump in auto at the completion of the test. On February 3 PG&E staff determined that the fuel oil pressure regulating valves on all DEGs should have a buna pad as a soft seat. However, none of the valves had the buna pad. PG&E staff felt that the lack of a soft seat for the fuel oil pressure regulating valve on DEG 1-2 was at least a contributor, if not the cause, of the loss of priming tank level. On February 4 PG&E staff developed a prompt operability assessment for the lack of soft seats on the fuel oil pressure regulating valves. The prompt operability assessment was developed using Procedure OM7.ID12, “Operability Determination,” Revision 8, and it also encompassed the loss of priming tank level for DEG 1-2.

PG&E staff determined that a prompt operability assessment was not necessary following the November 27, 2003 discovery of the increased loss of priming tank level because the condition was within the design of the plant and would be adequately addressed through plant procedures. For that reason, PG&E staff did not consider the increased loss of priming tank level to be a degraded condition. The inspectors compared PG&E’s reasoning against Procedure OM7.ID12 and Generic Letter 91-18, “Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions,” Revision 1.

Generic Letter 91-18 describes a degraded condition as a condition in which there has been any loss of quality or functional capability. The DEG priming tanks gradually lose some level, and that level is regained by the daily automatic running of the magnetic priming pumps. However, DEG 1-2 experienced a marked increase in priming tank leakage on November 27, 2003. The inspectors determined that, without any operator action, DEG 1-2 would become inoperable in 1.5 to 2.0 hours following the receipt of the low level alarm. PG&E staff speculated that the cause of the increased leak rate was a check valve potentially sticking open in the fuel oil day tank. Maintenance activities under Work Order C0186005 later verified that the check valve was not the source of the increased leak rate. Due to the marked increase in the DEG 1-2 priming tank leak rate, and the lack of a definitive cause for the increase, the inspectors determined that a degraded condition existed on DEG 1-2.

Procedure OM7.ID12 and Generic Letter 91-18 stated that substitution of automatic actions with manual actions require written procedures and consideration of pertinent differences such as operator timing and training. The inspectors reviewed Procedure AR PK17-07, “Diesel 12 Fuel Oil System,” Revision 11A, and found that while it instructed operators to verify level in the priming tank, it did not instruct them on how to address a low priming tank level. Additionally, Procedure STP M-9A directed operators to place the magnetic priming pump in auto following the test run. This action would cause the priming tank level to decrease until an operator placed the pump back into manual. Furthermore, PG&E staff did not analyze the required time for operators to respond to the alarm before prime would be lost in the fuel oil booster pump. Therefore, the inspectors determined that the plant procedures did not adequately address the degraded condition.

AR A0595440 stated that “As long as level is maintained in the priming tank, the diesel remains operable.” AR A0595440 also stated that running the magnetic priming pump in manual was a interim measure. Operators discovered that if the priming pump was not running in manual, level would be lost in the priming tank. Per Procedure OM7.ID12, a compensatory measure is an action that must be taken to maintain operability of a system, and if a compensatory measure is taken, then a prompt operability assessment is required. The inspectors determined that running the magnetic priming pump in manual was a compensatory measure because it was an action taken outside of the normal equipment configuration and procedural guidance, in order to maintain operability until a permanent corrective action is put into place. Therefore, the inspectors determined that PG&E staff failed to promptly address a degraded condition with regards to DEG 1-2 priming tank level.

Analysis. The performance deficiency associated with this finding is the failure to promptly identify and address a degraded condition, which resulted in an additional challenge to operators. The finding impacted the mitigating systems cornerstone and was more than minor since it affected the configuration control and procedure quality attributes. By failing to ensure that compensatory measures and/or appropriate procedure modifications were in place to maintain priming tank level, operators were faced with an additional instance of having to restore priming tank level. Using the SDP Phase 1 Worksheet in IMC 0609, the inspectors determined that the deficiency was confirmed not to result in a loss of function per Generic Letter 91-18. Specifically, the inspectors calculated that it would take 1.5 to 2.0 hours before the fuel oil booster pump would lose prime and that operators had responded within that time frame. Therefore, the finding was determined to be of very low safety significance.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI states, in part, that conditions adverse to quality are to be promptly identified and corrected. Contrary to the above, PG&E failed to adequately evaluate the loss of fuel oil in the DEG 1-2 priming tank and institute appropriate measures to ensure operability and prevent further challenges from the degraded condition. Because the failure to promptly identify and correct this degraded condition was determined to be of very low safety significance and has been entered into the corrective action program as AR A0604618, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/04-02-04, Failure to Adequately Address Loss of Diesel Fuel Oil Level in Priming Tank.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed five 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 were compared to the Technical Specifications and the FSAR Update. Additionally, the inspectors verified the tests were adequate for the scope of work and were performed as prescribed, jumpers and test equipment were properly removed after testing, and test equipment range, accuracy, and calibration were consistent for the application. The following selected maintenance activities were reviewed by the inspectors:

- Unit 2, digital rod position indication corrective maintenance for Shutdown Bank Rod N-11 on February 5
- Unit 2, control room pressurization Damper VAC-2-MOD-1A thermal overload preventive maintenance on February 9
- Unit 1, RHR Pump 1-2 routine maintenance outage window on February 11
- Unit 2, DEG 2-1 post-maintenance testing following automatic voltage regulator card replacement on February 19 - 20
- Unit 2, seismic trip X-axis YT-201 was found broken on March 3

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors evaluated one routine surveillance test 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 M-9A, "Diesel Engine Generator Routine Surveillance Test," Revision 65, on January 29 for Unit 1

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

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

- Modify turbine building high energy line break Louvers 11-15 (AR A0595233 and Work Order C0185847)

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Emergency Preparedness Evaluation (71114.06)

a. Inspection Scope

The inspectors witnessed one emergency preparedness drill that included the emergency plan implementation conducted on January 30, 2004. The scenario simulated an earthquake, main steam line break, and a steam generator tube rupture. The scenario continued with damage to fuel cladding and a radiological release to the environment to demonstrate PG&E's capabilities to implement the emergency plan. The inspectors witnessed PG&E staff performance in the Technical Support Center and the Emergency Offsite Facility. The inspectors also attended PG&E's self-critique of the scenario.

b. Findings

No findings of significance were identified.

3. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Reactor Safety Performance Indicator Verification

a. Inspection Scope

The inspectors verified six samples of performance indicators. The inspectors reviewed these indicators for the period from the first quarter of 2003 through the fourth quarter of 2003 to assess the accuracy and completeness of the indicator. The inspectors reviewed plant operating logs and licensee monthly operating reports to support this inspection. The inspectors used NEI 99-02, "Regulatory Assessment Performance Indicator Verification," Revision 2, as guidance for this inspection.

- Units 1 and 2 Reactor Scrams (Trips)
- Units 1 and 2 Reactor Scrams with a Loss of Normal Heat Removal
- Units 1 and 2 Unplanned Transients

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Units 1 and 2 Containment Penetrations

a. Inspection Scope

The inspectors reviewed the performance and maintenance activities associated with the Units 1 and 2 containment penetrations. The inspectors verified that complete and accurate identification of the problem was made in a timely manner, commensurate with its significance and ease of discovery. They also evaluated issues regarding maintenance effectiveness, operability, reportability, generic implications, and extent of condition. For identified problems, the inspectors reviewed their classification and prioritization, root and contributing causes, and corrective actions.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution Crosscutting Aspect

The finding associated with the Diablo Canyon Power Plant Unit 1, DEG 1-2 increased loss of fuel oil level in priming tank was identified as having problem identification and resolution crosscutting aspects (Section 1R16).

4OA5 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 resident inspectors continued to evaluate the following factors to determine whether the financial condition and power needs of the station impacted plant safety. The factors reviewed included: (1) impact on staffing, (2) corrective maintenance backlog, (3) corrective action system backlogs, (4) changes to the planned maintenance schedule, (5) reduction in outage scope, (6) availability of emergency facilities and operability of emergency sirens, and (7) grid stability (i.e., availability of offsite power to the switchyard, status of the operating reserves, and main generator Volt-Ampere reactive loading).

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

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

Exit Meeting Summary

The resident inspection results were presented on April 8, 2004, to Mr. James R. Becker, Vice President - Diablo Canyon Operations and Station Director, 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
L. Cluff, Director, Geosciences Department
J. Hays, Director, Maintenance Services
B. Horstman, Senior Civil Engineer
S. Ketelsen, Manager, Regulatory Services
M. Lemke, Manager, Emergency Preparedness
D. Oatley, Vice President and General Manager, Diablo Canyon
L. Parker, Supervisor, Regulatory Services
P. Roller, Director, Operations Services
J. Shoulders, Manager, Design Engineering
J. Tompkins, Director, Site Services
L. Womack, Vice President, Nuclear Services
D. Wong, Supervisor, Civil Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

50-275:323/04-02-01	NCV	Failure to Translate DEG Fuel Oil Volume Design Basis Assumptions into Implementing Procedure. (Section 1R04.4)
50-275; 323/04-02-02	NCV	Failure to Provide Adequate Procedures for Preventive Maintenance and Operation of Limitorque Motor-Operated Valves (Section 1R04.5)
50-275; 323/04-02-03	NCV	Failure to Control Placement of Temporary Equipment With Regards to Potential Seismic Impact on Safety-Related Systems (Section 1R14.4)
50-275/04-02-04	NCV	Failure to Adequately Address Loss of Diesel Fuel Oil Level in Priming Tank (Section 1R16)

Closed

None

LIST OF DOCUMENTS REVIEWED

Section 1R14: Operator Performance During Non-Routine Evolutions and Events

Procedures
CP M-4, Earthquake, Revisions 18A and 19
STP I-72B, Reactor Seismic Trip Channels Calibration, Revision 16

Special Reports
03-04, Special Report 03-04: San Simeon Earthquake of December 22, 2003
03-03, Special Report 03-03: Seismic Event of October 18, 2003:
03-04, Supplement to Special Report 03-04: San Simeon Earthquake of December 22, 2003

Plans
ERP 2003-02, Event Response Plan 12.22.2003 San Simeon 6.5 Earthquake

Section 1R19: Post-Maintenance Testing

Work Orders
C0184053
C0183559
R0208201
R0022688

Procedures
STP P-RHR-12, "Routine Surveillance Test of RHR Pump 1-2," Revision 14

Section 4OA2: Problem Identification and Resolution

Action Requests

A0553350	A0554890	A0571891	A0581945
A0554116	A0554897	A0576813	A0601304
A0554333	A0563962	A0581659	

LIST OF ACRONYMS

AFW	auxiliary feedwater
AR	action request
DEG	diesel engine generator
CFR	*Code of Federal Regulations*
FSAR	Final Safety Analysis Report
IMC	Inspection Manual Chapter
NCV	noncited violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records System
PG&E	Pacific Gas and Electric Company
RHR	residual heat removal
SDP	Significance Determination Process