UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
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August 9, 2005

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 05000275/2005003 AND 05000323/2005003

Dear Mr. Rueger:

On June 30, 2005, the U.S. Nuclear Regulatory Commission completed an inspection at your Diablo Canyon Power Plant, Units 1 and 2, facility. The enclosed integrated report documents the inspection findings that were discussed on July 5, 2005, 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 was one NRC-identified finding, one self-revealing finding, and two licensee-identified findings of very low safety significance (Green) identified in this report. These findings involved violations of NRC requirements. However, because of their very low risk significance and because they are entered into your corrective action program, the NRC is treating these three findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Diablo Canyon Power Plant.

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

Sincerely,

/RA/

William B. Jones, Chief
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Division of Reactor Projects

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

Enclosure:
NRC Inspection Report 05000275/2005003
and 05000323/2005003
w/attachment: Supplemental Information

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8/9/05	8/9/05	8/4/05	8/5/05	8/4/05

C:DRS/EB1	C:DRS/EB2	C:DRP/B	
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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-275, 50-323
Licenses:	DPR-80, DPR-82
Report:	05000275/2005003 05000323/2005003
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	April 1 through June 30, 2005
Inspectors:	D. L. Proulx, Senior Resident Inspector T. W. Jackson, Senior Resident Inspector T. A. McConnell, Resident Inspector J. H. Nadel, Reactor Inspector R. E. Lantz, Senior Emergency Preparedness Inspector T. F. Stetka, Senior Operations Engineer G. W. Johnston, Senior Operations Engineer L. T. Ricketson, Senior Health Physicist J. F. Drake, Operations Engineer
Approved By:	W. B. Jones, Chief, Project Branch B Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000275/2005-003, 05000323/2005-003; 04/01/05 - 06/30/05; Diablo Canyon Power Plant Units 1 and 2; problem identification and resolution and maintenance risk assessment.

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

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A self-revealing NCV was identified for the failure to correct a condition adverse to quality, in accordance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions." Specifically, Pacific Gas and Electric Company failed to effectively implement interim corrective actions to remove carbonized lube oil from Diesel Engine Generator 1-1 lube oil system, which led to Diesel Engine Generator 1-1 unplanned unavailability. A problem identification and resolution crosscutting aspect was identified for the failure to effectively correct the impact of carbonized lube oil on Diesel Engine Generator 1-1. This issue has been entered into the corrective action program as Action Request A0638887.

  The finding impacted the Mitigating Systems Cornerstone and was more than minor since it impacted the cornerstone objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. With respect to this finding, the carbonized oil clogged the precirculation lube oil line and required the unplanned unavailability of Diesel Engine Generator 1-1 to clean the line. Using the significance determination process Phase 1 screening worksheet in Appendix A of IMC 0609, the inspectors determined that there was no loss of an actual safety function, no loss of a safety-related train for greater than the diesel engine generator Technical Specification allowed outage time, and the finding is not potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event. Therefore, the finding was determined to be of very low safety significance (Section 1R13).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, for failure to take corrective actions to prevent recurrence for a significant condition adverse to quality. On January 27, 2005, Pacific Gas and Electric Company identified that the Unit 2 pressurizer safety valve lift setpoints were determined to be significantly out of tolerance, as compared to the historical and industry-wide experience. A problem identification and resolution crosscutting aspect was identified for the failure to identify the root cause and propose any corrective actions to prevent recurrence, despite a history of pressurizer safety valve lift setpoints being out of tolerance. This issue has been entered into the corrective action program as Action Request A0630775.

The finding impacted the Mitigating Systems Cornerstone and was determined to be more than minor because it impacted the cornerstone objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. Using the significance determination process Phase 1 screening worksheet of Inspection Manual Chapter 0609, the finding was determined to be of very low safety significance since it did not represent an actual loss of safety function, represent an actual loss of a safety function for a single train for greater than the Technical Specification allowed outage time, or screen as potentially risk significant due to seismic, fire, flooding, or severe weather initiating events. Specifically, analysis demonstrated that the two valves having lift setpoints 4.4 and 3.6 percent low would not adversely affect the proper lift of the power-operated relief valves, and would not result in a spurious lift of the pressurizer safety valves during a normal transient (Section 4OA2.1).

B. Licensee-Identified Violations

Violations of very low safety significance, which were identified by Pacific Gas & Electric Company have been reviewed by the inspectors. Corrective actions taken or planned by Pacific Gas and Electric Company have been entered into their corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Diablo Canyon Unit 1 began this inspection period at 100 percent power. On June 3, 2005, operators reduced Unit 1 reactor power to 50 percent due to a main condenser tube leak. Operators returned Unit 1 reactor power to 100 percent on June 5, 2005. Unit 1 remained at 100 percent power for the rest of the inspection period.

Diablo Canyon Unit 2 began this inspection period at 100 percent power. 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

1R01 Adverse Weather (71111.01)

a. Inspection Scope

The inspectors performed one adverse weather protection inspection this quarter. The inspectors performed reviews of the design features, equipment, and plant preparation for the hot weather. Specifically, the inspectors reviewed the hot weather protection procedures, the condition of ventilation equipment, and the condition of temperature monitoring instruments.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

Partial System Walkdowns

a. Inspection Scope

The inspectors performed three partial system walkdowns during this inspection period. The inspectors observed valve alignment, the availability of electrical power and cooling water, labeling, lubrication, ventilation, structural support, and material condition. The following systems were inspected during the inspection period:

- Unit 1 Component Cooling Water Pumps 1-2 and 1-3 when Component Cooling Water Pump 1-1 was in a maintenance outage window on April 20, 2005

- Unit 2 Residual Heat Removal (RHR) Pump 2-2 when RHR Pump 2-1 was in a maintenance outage window on May 10, 2005

- Units 1 and 2 diesel engine generators (DEGs) when Startup Transformer 1-1 was in a maintenance outage window on June 13, 2005

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

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

.1 Routine Observations

a. Inspection Scope

The inspectors performed nine 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 35; STP M-69B, “Monthly CO2 Hose Reel and Deluge Valve Inspection,” Revision 14; STP M-70C, “Inspection/Maintenance of Doors,” Revision 10; and OM8.ID4, “Control of Flammable and Combustible Materials,” Revision 14. Specific risk-significant areas inspected included:

- Unit 1, Fire Area 7-C, communications room
- Unit 2, Fire Area 7-D, communications room
- Unit 1, Fire Area 12-A, 4kV cable spreading room
- Unit 1, Fire Area 12-B, 4kV cable spreading room
- Unit 1, Fire Area 12-C, 4kV cable spreading room
- Unit 2, Fire Area 23-A, 4kV cable spreading room
- Unit 2, Fire Area 23-B, 4kV cable spreading room
- Unit 2, Fire Area 23-C/C1, 4kV cable spreading room
- Unit 1, compensatory measures for out-of-service intake fire hydrants

b. Findings

No findings of significance were identified.

.2 Fire Drill (71111.05A)

k. Inspection Scope

On May 10, 2005, Pacific Gas and Electric Company (PG&E) performed a fire drill that involved a fire in Auxiliary Transformer 1-1. The inspectors verified that:

- PG&E firefighting personnel properly donned protective clothing and self-contained breathing apparatus
- fire hoses were properly laid out and could reach the fire
- the fire area of concern was entered in a controlled manner
- adequate equipment was brought to the fire scene
- appropriate command, control, and communication was implemented
- the fire brigade checked for fire victims and potential fire propagation into other plant areas
- preplan firefighting strategies were used

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Licensed Operator Requalification

The inspectors performed one sample of licensed operator requalification.

a. Inspection Scope

On May 3, 2005, the inspectors witnessed one operator requalification examination in the simulator. The first scenario involved an earthquake, a reactor trip with a subsequent loss of all vital 4 kV buses with a power-operated relief valve stuck open. The inspectors verified the crew's ability to meet the objectives of the training scenarios and attended the postscenario critique to verify that crew weaknesses were identified and corrected by PG&E staff.

b. Findings

No findings of significance were identified.

.2 Biennial Inspection

The inspectors performed one biennial inspection on licensed operator requalification on May 16-19, 2005.

a. Inspection Scope

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

Furthermore, the inspectors: (1) interviewed seven personnel, including four operators, two instructors/evaluators, and a training supervisor, regarding the policies and practices for administering requalification examinations; (2) observed the administration of four dynamic simulator scenarios to two requalification crews; and (3) observed six evaluators administer 10 performance measures, including 4 in the control room simulator in a dynamic mode and 6 in the plant under simulated conditions.

The inspectors also reviewed the written and operating examinations and operator performance on those examinations. Examination results were assessed to determine if they were consistent with the guidance contained in NUREG 1021 and Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process."

The review included an assessment of 45 operating examination job performance measures (JPMs) that were used in the biennial requalification cycle to determine if they provided adequate discrimination at the minimum acceptable level of operator performance. The assessment identified that approximately 5 percent of the 45 JPMs did not provide an adequate basis to conclude the operator had demonstrated an understanding of the system. While it was identified that these JPMs covered high risk activities, actions were being taken by PG&E staff to improve the discriminatory validity of these JPMs.

The inspectors also reviewed the remedial process and the results of the biennial written examination. The results of the examinations were assessed to determine PG&E's appraisal of operator performance and the feedback of performance analysis to the requalification training program. The inspectors interviewed members of the training department and operating crews to assess the responsiveness of the licensed operator requalification program. The inspectors also observed the examination security maintenance for the operating tests during the examination week.

In addition, the inspectors assessed the Diablo Canyon Unit 1 plant-referenced simulator for compliance with 10 CFR 55.46, Simulator Facilities, using Baseline Inspection Procedure 71111.11 (Section 03.11). This assessment included the adequacy of PG&E's simulation facility for use in operator licensing examinations and for satisfying experience requirements as prescribed by 10 CFR 55.46. The inspectors reviewed a sample of simulator performance test records (transient tests, surveillance tests, malfunction tests, and scenario-based tests), simulator discrepancy report records, and processes for ensuring simulator fidelity commensurate with 10 CFR 55.46. The inspectors reviewed selected simulator configuration reports generated by PG&E staff that did not result in changes to the configuration of the simulator to assess the responsiveness of PG&E's simulator configuration management program. The inspectors also interviewed members of PG&E's simulator configuration control group as part of this review.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors performed two inspection samples of PG&E's Maintenance Rule implementation for equipment performance problems. The inspectors assessed whether the equipment was properly placed into the scope of the rule, whether the failures were properly characterized, and whether goal setting was recommended, if required. Procedure MA1.ID17, "Maintenance Rule Monitoring Program," Revision 15, was used as guidance. The inspectors reviewed the following action requests (ARs).

- (Unit 2) AR A0634207, "Maintenance Rule Performance Criteria, Goal Setting Review," for the Unit 2 nuclear steam supply sampling system

- (Unit 2) AR A0634831, "Maintenance Rule Performance Criteria, Goal Setting Review," for the Unit 2 containment isolation system

b. Findings

No findings of significance were identified.

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

The inspectors performed eight 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 whether PG&E had properly used their risk categories, preservation of key safety functions, and implementation of work controls. The inspectors used Procedure AD7.DC6, "On-line Maintenance Risk Management," Revision 8, as guidance. The inspectors specifically observed the following work activities during the inspection period.

- (Unit 1) Service cooling water heat exchanger cleaning on May 9, 2005 (AR 0637926)
- (Units 1 and 2) Removing the Morro Bay to Diablo Canyon 230 kV line from service during severe thunderstorm warnings on April 28, 2005
- (Unit 2) Maintenance outage window on the Diesel Fuel Oil Transfer Pump 0-2 on June 7, 2005
- (Unit 1) Maintenance outage window on Startup Transformer 1-1 on June 13, 2005

b. Findings

No findings of significance were identified.

.2 Emergent Work

f. Inspection Scope

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

- (Unit 1) Low pressurizer pressure alarm on April 15, 2005 (AR A0636418)
- (Unit 2) Failed valve position indication on Valve LWS-2-FCV-255 with Valve LWS-2-FCV-256 inoperable due to repairs to failed air operator on April 28, 2005 (AR A0637399)

- (Unit 1) DEG 1-1 low precirculating lube oil pressure (AR A0638887)
- (Unit 2) Solid-State Protection System Logic Board AA205 failed surveillance test on June 13, 2005 (AR A0640156)

b. Findings

Introduction. A Green self-revealing noncited violation (NCV) was identified for the failure to correct a condition adverse to quality, in accordance with 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions.” Specifically, PG&E failed to effectively implement interim corrective actions, which led to the unplanned unavailability of DEG 1-1 to remove carbonized lube oil from the lube oil system.

Description. The lube oil for the DEGs is maintained above 90EF by an electric precirculating lube oil pump and an electric lube oil heater. Once the DEG’s are running, the pre-circulating lube oil pump and heater are bypassed and the lube oil is circulated by a shaft-driven lube oil pump. While the DEG is in standby, the precirculating lube oil pump is constantly running and the heater is controlled by a thermostat. The lube oil travels, in order, from the lube oil reservoir, through the precirculating lube oil pump, the electric heater, the lube oil filter, a flow sensing switch, a check valve, the lube oil heat exchanger, lube oil strainers, and engine components and back to the lube oil reservoir.

In 1997, PG&E identified the lube oil was carbonizing onto the heating elements. As a corrective action, PG&E increased the surface area of the lube oil heater while maintaining the total heat output to 12 kW. However, PG&E staff continued to find carbonized lube oil in the precirculating lube oil system and the lube oil filter. In response to the low precirculating lube oil pressure on DEG 1-3 (AR A0585511) on June 25, 2003, PG&E established, as part of their corrective actions to prevent recurrence, that downstream piping would be inspected for debris. Procedure STP M-21-ENG.1, “Diesel Engine Generator Inspection,” Revision 5, was changed to include removal and inspection of the flow switch. However, it did not provide direction to inspect the precirculating lube oil piping for carbonized lube oil.

On May 22, 2005, operators noticed that the standby lube oil pressure for DEG 1-1 was 9 psig when its acceptable pressure is to be at least 10 psig. PG&E had completed an operability assessment that assured the DEGs would remain operable at a lube oil pressure of 7 psig when the oil temperature is above 90EF. On May 29, 2005, the pressure decreased to 6 psig and the diesel generator was declared inoperable when the maintenance technicians were no longer able to restore precirculating lube oil pump pressure to above 7 psig by adjusting the pump pressure. PG&E initiated Work Order C0197194 to disassemble and determine the cause of the low pressure. On May 30, 2005, maintenance technicians found the heaters had a layer of carbonized lube oil and that downstream Flow Switch FS-44 and Check Valve DEG-1-173 were blocked by carbonized oil. The operator’s response to the low lube oil pressure was to adjust the pump discharge pressure higher. This increased the pressure against Flow

Switch FS-44 and transferred more carbonized lube oil from the heaters. PG&E staff attributed the clogging of the check valve to transport of the debris from the upstream flow switch. On June 2, 2005, PG&E initiated actions to ensure that the other DEG's precirculating lube oil systems were inspected and cleaned as needed.

The inspectors determined that PG&E failed to take effective corrective actions to prevent carbonized lube oil from impacting DEG 1-1 operability and availability. As discussed in NRC Inspection Report 05000275; 323/2003007, the inspectors had previously addressed the carbonized lube oil found in the Diablo Canyon DEGs. In that report, the inspectors discussed the failure of PG&E to take corrective actions to mitigate the carbonized lube oil impact on DEG 1-3. The inspectors found that PG&E had initiated interim corrective actions since the finding with DEG 1-3; however, the interim corrective actions to inspect the precirculating lube oil piping as well as the flow switch were not included in Procedure STP M-21-ENG.1 or other instructions. The inspectors determined that this finding had crosscutting aspects in the area of problem identification and resolution for the failure to implement the interim corrective actions.

Analysis. The performance deficiency associated with this finding is the failure to implement the interim corrective actions to prevent carbonized oil from accumulating on the lube oil filter and affecting DEG operability and availability. This finding impacted the mitigating systems cornerstone and was more than minor since it impacted the cornerstone objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. Using the SDP Phase 1 Screening Worksheet in Appendix A of Inspection Manual Chapter (IMC) 0609, the inspectors determined that there was no loss of an actual safety function, no loss of a safety-related train for greater than the DEG Technical Specification allowed outage time, and the finding is not potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event. This 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, such as nonconformances, are to be promptly identified and corrected. Contrary to the above, PG&E failed effectively to correct the impact of carbonized lube oil that partially blocked a precirculation lube oil line for DEG 1-1. Because the failure to correct this nonconformance was determined to be of very low safety significance and has been entered into the corrective action program (CAP) as AR A0638887, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/05-03-01, Failure to Correct Diesel Engine Generator Lube Oil Carbonization.

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

The inspectors observed two nonroutine plant evolutions/events during this inspection period.

.1 (Unit 2) Failed Eagle 21 Instrument Rack

a. Inspection Scope

(Unit 2) On May 6, 2005, the Eagle 21 rack shut down due to the loss of function in the automatic loop communication circuit. The operators performed Operating Procedure OP AP-5, “Malfunction of Protection or Control Channel,” Revision 23, without any complications. The system was restored to full operational capability within 12 hours of the fault. There were no system actuations due to this failure. The inspectors observed the performance of the operating procedure, the test, and restoration activities.

b. Findings

No findings of significance were identified.

.2 (Unit 1) Main Condenser Tube Leak

a. Inspection Scope

On June 3, 2005, reactor power was reduced to approximately 50 percent. This was necessary to allow the identification and repair of a main condenser saltwater tube leak. The inspectors observed the downpower reactivity changes according to the ramp plan, the turbine load changes, and the securing of the circulating water system. The inspectors observed the control room operators' usage of the operating procedures.

b. Findings

No significant findings were identified.

1R15 Operability Evaluations (71111.15)

c. Inspection Scope

The inspectors reviewed four 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 ARs and operability evaluations:

- (Unit 2) Discoloration and water in the same conduit as Auxiliary Saltwater Pump 2-1 vault exhaust fan power cable (AR A0634925)

- (Unit 2) Oil leak from Centrifugal Charging Pump 2-1 auxiliary oil pump (AR A0637233)

- (Unit 1) DEG 1-1 low lube oil pressure (ARs A0638887 and A0589167)

- (Unit 2) Undocumented repairs and out-of-tolerances for DEG 2-3 turbo charger (AR A0640858)

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

.1 Cumulative Review of Operator Workarounds

a. Inspection Scope

The inspectors reviewed the cumulative effect of operator workarounds to identify any potential impacts on the functionality of mitigating systems or the operator's ability to implement abnormal and emergency operating procedures. As part of the inspection effort, the inspectors considered PG&E's evaluation of the workarounds, operational practices, the amount of training or knowledge needed for the workaround, corrective actions, compensatory measures, and adverse operational environments.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed the permanent modification packages for the installation of redundant differential current relays for the 230 kV and 500 kV systems for both Units 1 and 2. The system is designed to sense a fault in the electrical distribution system and isolate the fault by tripping the appropriate breakers. The differential relay system would subsequently initiate a reactor trip signal. The inspectors reviewed the precautions, seismic and fire risk assessments, and scope of the modification. The inspectors also reviewed the design basis, licensing bases, and performance capability of risk significant systems and components to ensure that they were not degraded by this modification.

b. Inspection Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

b. Inspection Scope

The inspectors reviewed two 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) DEG 2-1 differential overcurrent relay calibration and replacement on April 30, 2005 (Work Order C0196108)

- (Units 1 and 2) component cooling water pressurization nitrogen system relief valve and pressure regulator replacement (Work Order C0190390)

- (Unit 2) RHR heat exchanger Drain Valve RHR-2-8722B replacement (Work Order C0196397)

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors evaluated six routine surveillance tests to determine if PG&E complied with the applicable Technical Specification requirements to demonstrate that the 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 the proper test equipment was utilized, preconditioning occurred, test acceptance criteria agreed with the equipment design basis, and the equipment was returned to normal alignment following the test. The following tests were evaluated during the inspection period:

- (Unit 2) Procedure STP I-37-N50, “NIS Flux deviation N50 Calibration,” Revision 4 on April 6

- (Unit 1) Procedure STP M-12B, “Battery Charger Performance Test,” Revision 13 on April 26

- (Unit 2) Procedure STP P-RHR-21, “Routine Surveillance test of RHR Pump 2-1,” Revision 18 on May 11

- (Unit 1) Procedure STP M-21A, “Main Turbine/Generator Trip Functional Tests,” Revision 33, on June 19, 2005

- (Unit 2) Procedure STP I-2B, “Nuclear Power Range Channel Analog Channel Operational Test,” Revision 31, on June 20, 2005

- (Unit 1) Procedure STP M-9A, “Diesel Engine Generator Routine Surveillance Test,” Revision 68A, on June 25, 2005

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

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

The inspectors completed one sample of emergency action level and emergency plan changes during the inspection period.

a. Inspection Scope

The inspectors reviewed the Diablo Canyon Emergency Plan, Revision 4, Change 5, to Section 7, submitted in December 2004. The revision updated the seismic monitoring system description based on installation of a new seismic monitoring and indication system. The terminology of basic and supplemental seismic systems was removed, the functions of which were combined and improved into the new seismic monitoring system. Section 3 of the FSAR was referenced for a description of the new seismic system. The role of the earthquake force monitor was also emphasized as the indicator on which emergency classification is based.

The revisions were compared to the previous revisions, to the criteria of NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants,” Revision 1, and to the requirements of 10 CFR 50.47(b) to determine if PG&E adequately implemented the emergency plan change process described in 10 CFR 50.54(q).

b. Findings

No findings of significance were identified.

1EP6 Emergency Preparedness Evaluation (71114.06)

a. Inspection Scope

On May 3, 2005, the inspectors witnessed an operator requalification examination in the simulator that included emergency preparedness performance indicator opportunities for emergency classification and notification. The scenario simulated an earthquake, with damage resulting in a loss-of-coolant accident (LOCA). During the scenario, conditions arose that required operators to declare an Alert due to the earthquake and a Site Area Emergency due to the loss of coolant accident. The inspectors attended and verified PG&E's self-critique of the scenario.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Problem Identification and Resolution (71152)

.1 Unit 2 Pressurizer Safety Valve Lift Setpoints

a. Inspection Scope

The inspectors reviewed Licensee Event Report (LER) 2005-01-00, "Technical Specification 3.4.10 not Met During Pressurizer Safety Valve Testing due to Random Lift Spread," and AR A0630775 to evaluate the effectiveness of PG&E's corrective actions with respect to out-of-tolerance lift setpoints of the Unit 2 pressurizer safety valves. In addition, the inspectors reviewed the operating experience information and previous LERs on this subject to determine if PG&E had adequately addressed this issue.

b. Findings

Introduction. The inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion XVI, for failure to take corrective actions to prevent recurrence for a significant condition adverse to quality. On January 27, 2005, PG&E identified that the Unit 2 pressurizer safety valve lift setpoints were determined to be significantly out of tolerance, as compared to the historical and industry-wide experience. However, PG&E failed to identify the root cause and propose any corrective actions to prevent recurrence, despite a history of pressurizer safety valve lift setpoints being out of tolerance.

Description. Diablo Canyon was designed with three pressurizer safety valves per unit to protect the plant from overpressure transients. The plant has 6-inch Crosby relief valves (Model HP-BP-86 686) installed to meet this function. The nominal lift setpoint was determined to be 2485 psig. Technical Specification 3.4.10 requires three pressurizer safety valves to be operable with lift settings between 2460 and 2510 psig (i.e., 2485+/- 1 percent). The bases for this Technical Specification states that the minimum setting is based on not interfering with the power-operated relief valve lift setpoints and ensuring that spurious lifts of the pressurizer safety valves do not occur. The maximum setting is based on preventing the reactor coolant system from exceeding the American Society of Mechanical Engineers (ASME) code limit of 110 percent design pressure (2750 psig).

On March 28, 2005, PG&E submitted LER 50-323/2005-001-00. During Refueling Outage 2R11, two pressurizer safety valves were removed from Unit 2 and tested at an offsite facility. On January 27, 2005, the vendor reported that as-found lift setpoints for Valves RCS-2-RV-8010B and RCS-2-RV-8010C were outside of the Technical Specification 3.4.10 tolerance of +/- 1 percent. The as-found lifts were 4.4 and 3.6 percent low, respectively.

The LER stated that no corrective actions to prevent recurrence were necessary. PG&E stated that the condition was caused by normal/expected setpoint drift. PG&E also stated that the out-of-tolerance lifts had no safety significance and the valves could not inherently meet a +/- 1 percent tolerance. Therefore, corrective action to prevent recurrence was unnecessary. The LER also stated that the nonrepeatability of pressurizer safety valve lift setpoints was an industry-wide problem being addressed generically with the Westinghouse Owners Group. The LER cites WCAP-12910, "Pressurizer Safety Valve Set Pressure," as a reference for these statements.

The inspectors performed a search of the LER database and noted that other licensees had submitted LERs concerning out-of-tolerance pressurizer safety valve lift setpoints. However, the inspectors noted that PG&E had submitted five LERs in the past 5 years, while no other licensees had submitted more than two for the same time period. In addition, only one other licensee had as-found lift setpoints of the pressurizer safety valves greater than 3 percent out of tolerance. The licensee determined that the root cause was the relaxation of the actuating spring and initiated a preventive maintenance task to examine and replace these springs as needed. Licensees that submitted LERs because of pressurizer safety valves being up to about 2 percent out of tolerance pursued Technical Specification amendments or performed re-analyses of transient response to relax the setpoint tolerances of the pressurizer safety valves to +/- 3 percent.

The inspectors concluded that, because of the magnitude of the out-of-tolerance lift setpoints for the Unit 2 pressurizer safety valves (up to 4.4 percent), PG&E did not take adequate action to determine the root cause and provide corrective action to prevent recurrence. The magnitude of the out-of-tolerance lift setpoints was in excess of that seen in the industry and at Diablo Canyon, which cannot be attributed to routine setpoint drift. The failure to determine the root cause and provide for corrective actions to prevent recurrence for this significant condition adverse to quality is a violation of 10 CFR Part 50, Appendix B, Criterion XVI. This issue is a problem identification and resolution crosscutting aspect for failure to determine the root cause and provide corrective action to prevent recurrence for significant Unit 2 pressurizer safety valve lift setpoint out-of-tolerance conditions. PG&E has initiated Nonconformance Report (NCR) N0002197 to determine the root cause and provide for corrective actions to prevent recurrence of the significant pressurizer safety valve lift setpoint out-of-tolerance condition.

Analysis. The performance deficiency associated with this finding is the failure to determine the root cause and provide for the corrective actions to prevent recurrence of a significant condition adverse to quality. The finding impacted the Mitigating Systems Cornerstone and was determined to be more than minor because it impacted the cornerstone objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. Using the significance determination process Phase 1 screening worksheet of IMC 0609, the finding was determined to be of very low safety significance since it did not represent an actual loss of safety function, represent an actual loss of a safety function for a single train for greater than the Technical Specification allowed outage time, or screen as potentially risk significant due to seismic, fire, flooding, or severe weather initiating events. Specifically, analysis demonstrated that the two valves having lift setpoints 4.4 and 3.6 percent low would not adversely affect the proper lift of the power-operated relief valves and would not result in a spurious lift of the pressurizer safety valves during a normal transient.

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 and, in the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action is taken to preclude repetition. Contrary to the above, as of March 28, 2005, a significant condition adverse to quality existed, but the cause was not determined and corrective actions to preclude repetition were not provided. Specifically, Pressurizer Safety Valves RCS-2-RV-8010B and RCS-2-RV-8010C had as-found lift setpoints that were 4.4 and 3.6 percent out of tolerance (greater than the Technical Specification allowable +/- 1 percent), but PG&E did not determine the root cause nor provide corrective action to preclude repetition. Because this violation is of very low safety significance and because it has been entered into the CAP as AR A0630775 and NCR N0002197, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/05-03-02, Failure to Provide Corrective Action to Prevent Recurrence for Pressurizer Safety Valve Out-of-Tolerance Lift Setpoints.

.2 Semiannual Review

h. Inspection Scope

The inspectors performed a semiannual review of PG&E- and NRC-identified trends that might indicate the existence of more significant safety issues. In particular, the inspectors reviewed the following:

- System and component health reports

- Quality assurance audits reports
- Trend reports
- Diablo Canyon internal performance indicators
- NRC inspection reports
- NRC end-of-cycle assessment

b. Findings

No findings of significance were identified.

In the 2003 end-of-cycle assessment letter dated March 3, 2004, and as updated in the 2004 midcycle assessment letter dated August 30, 2004, the NRC determined that there was a substantive crosscutting issue in the area of problem identification and resolution. This crosscutting issue was identified based on a number of corrective action findings, including those that involved inadequate extent of condition review, long-standing degraded equipment conditions, and inadequate root cause and problem analysis. Since that time, PG&E has taken several actions to improve their CAP. These improvements include the following:

- Management review of select ARs
- Initiation of a Corrective Action Review Board
- Enhancement of the apparent cause evaluations process (including training)
- Implementation of a CAP significance category and response matrix
- Revision of the root cause analysis process (including training)
- Establishment of CAP coordinators in the line organizations
- Improvements to the operability determination process
- Improvements to the CAP trending program
- Implementation of metrics to measure the performance of CAP

The inspectors reviewed the CAP performance metrics for the second quarter of 2005. The inspectors found that PG&E's metrics covering the operability determination program, corrective action due date extensions, quality of apparent cause analyses, effectiveness evaluations, use of operating experience, and self assessments demonstrated positive performance. However, the inspectors found that performance indicators covering significant repeat events and apparent cause average age would require additional attention from PG&E staff to improve trends in these two areas. Repeat issues in 2004 regarding a component cooling water leak on the Reactor Coolant Pump 1-3 oil cooler and emergency core cooling system pipe voiding highlighted the significant repeat events performance indicator. Also, six departments had an average apparent cause evaluation age of greater than 30 days for the month of May 2005. The inspectors noted that this trend was improving since there were 15 departments in the previous month that had an average apparent cause evaluation age of greater than 30 days.

Since the beginning of 2005, the inspectors have addressed four issues involving problem identification and resolution aspects. These issues are DEG lube oil carbonization (Section 1R13), pressurizer safety valve out-of-tolerance lift setpoints (Section 4OA2.1), refueling water storage tank (RWST) leakage (Section 4OA7), and RHR check valve leak-by (Section 4OA7).

The first issue involved inadequate interim corrective actions caused by poor translation of corrective actions to work orders and procedures. The other three issues involved long-standing degraded equipment conditions. In regard to the pressurizer safety valve issue, the inspectors discovered that PG&E did not have corrective actions to address the long-standing degraded condition. The RWST leakage issue has existed for a significant period of time. Although the overall leakage was bounded by the design basis for ECCS leakage, this degraded condition was allowed to exist without determining the actual source(s) for the leakage until the leakage increased to 6 gph in January 2005.

The RHR check valve issue had been in existence since Refueling Outage 1R6, but the inspectors determined that the cause determination and planned corrective actions were adequate to eliminate this long-standing equipment issue.

The inspectors acknowledged that NCR N0002195, “Long Standing Equipment Problems,” has provided several corrective actions to address the issue of long-standing degraded equipment conditions. NCR N0002195 identified the root causes of the long-standing degraded equipment conditions to be: (1) misaligned prioritization, authorization, and funding processes; and (2) and ineffective funding process. As corrective actions, PG&E is establishing a plant health committee and a senior review committee to facilitate the funding process. These committees will provide for a systematic funding process that maintains an overall perspective of plant issues, ensures that projects are funded based on safety, and will be intolerant to compensatory measures as long-term solutions. PG&E is also implementing a cost estimating and forecasting initiative action plan to systematically plan, schedule, and approve projects. Since this NCR was completed in June 2005, it is too soon to determine the effectiveness of these corrective actions.

As part of the effort to determine the root cause of long-standing equipment problems in NCR N0002195, PG&E reviewed several long-standing equipment issues, including those involving safety-related and/or risk-significant equipment. Examples of ongoing long-standing equipment issues that are being addressed by PG&E staff include ECCS voiding and containment fan cooler unit reverse rotation. The inspectors reviewed the list of long-standing equipment issues generated for NCR N0002195 and acknowledged that PG&E is taking action to identify the cause and apply corrective actions to the issues.

4OA3 Event Followup (71153)

.1 (Closed) LER 50-275/2003-001-00: Technical Specification 3.8.1, Action B.1, not Met due to Personnel Error.

This LER discussed an event in which Unit 1 operators failed to perform a conditional surveillance required in the Technical Specification. Technical Specification 3.8.1.B.1 requires, in part, that if one diesel engine generator is inoperable, then within one hour verify correct breaker alignment and power availability for the offsite power circuits. Contrary to the above, on October 9, 2003, DEG 1-3 became inoperable, but operators failed to perform the offsite power breaker alignment and power availability checks required by Technical Specification 3.8.1.B.1 because of personnel error. The inspectors determined that this was a violation of NRC requirements. However, this violation was considered a minor violation not subject to formal enforcement in accordance with Section IV of the NRC enforcement policy. This LER is closed.

.2 (Closed) LER 50-275/2004-001-00: Steam Generator Tube Plugging due to Stress Corrosion Cracking.

This LER discussed an event in which greater than one percent of the tubes in the Unit 1 steam generators required plugging. Technical Specification 5.5.9 requires that PG&E submit an LER to the NRC if, during steam generator eddy-current testing, greater than one percent of tubes required plugging. This LER satisfies the reporting requirement. No violations of NRC requirements were identified. This LER is closed.

.3 (Closed) LER 50-323/2004-001-00: Unplanned Valid Diesel Generator Auto-Start during Phase Sequence Check.

This LER discussed an event in which an unplanned start of DEG 2-1 during phase sequence checks on Unit 2 Bus G. Technicians connected test leads to the secondary windings of a potential transformer instead of the primary windings required by procedure because of personnel error. This event is discussed in detail in NRC Inspection Report 50-275; 323/2004-05, and a self-revealing violation of NRC requirements was identified (NCV 50-323/2004-05-09). No new information was provided in the LER that would change the disposition. This LER is closed.

.4 (Closed) LER 50-275/2004-002-00: Technical Specification 3.0.3 Required Shutdown Due to Technical Specification 3.7.7, "Vital CCW System," Not Met.

This LER discussed an event in which a Unit 1 Technical Specification 3.0.3 required shutdown occurred because Technical Specification 3.7.7 was not met. A weld leak, because of high cycle fatigue in the nonvital section of the Unit 1 component cooling water system, was identified and necessitated the shutdown. No violations of NRC requirements were identified. The inspectors determined that the LER adequately described the event, identified the root cause, and listed the corrective actions. This LER is closed.

.5 Tsunami Warning

a. Inspection Scope

At 7:50 p.m on June 14, 2005, a 7.0 magnitude earthquake struck approximately 90 miles northwest of Eureka, California. Based on the likelihood of a tsunami, the National Oceanic and Atmospheric Administration issued a tsunami warning at 7:51 p.m for the west coast of the United States. Due to the lack of expected wave action from the earthquake, the tsunami warning was canceled at 9:09 p.m.

At 8:41 p.m., Diablo Canyon Power Plant Units 1 and 2 received verbal notification of the tsunami warning, followed by a fax notification, from the San Luis Obispo Emergency Operations Center. At 8:50 p.m Diablo Canyon Power Plant Units 1 and 2 declared a Notification of Unusual Event (NOUE) due to the receipt of a tsunami warning from the California State Warning Center. Following receipt of the tsunami warning cancellation, Diablo Canyon Units 1 and 2 terminated the NOUE at 9:38 p.m. The earthquake was not sensed onsite by either the operators or the seismic instrumentation and no tsunami wave action was detected at the site.

Following the notification of a tsunami warning, operators entered Procedure CP M-5, "Tsunami Warning," Revision 11D. Per the procedure, PG&E staff evacuated the intake basin area and assembled the fire brigade to prepare for search and rescue activities and to observe water levels at the intake structure.

The inspectors followed operator actions in response the tsunami warning. Additionally, the inspectors reviewed the operator's actions associated with the NOUE and lessons learned from the event.

b. Findings

No findings of significance were identified.

4OA4 Crosscutting Aspects of Findings

Section 1R13 identified a problem identification and resolution crosscutting aspect for the failure to effectively correct the impact of carbonized lube oil on DEG 1-1.

Section 4OA2.1 identified a problem identification and resolution crosscutting aspect for the failure to determine the root cause and provide corrective action to prevent recurrence for significant Unit 2 pressurizer safety valve lift setpoint out-of-tolerance conditions.

4OA5 Other

.1 TI 2515/161 - Transportation of Reactor Control Rod Drives in Type A Packages

The inspectors completed one inspection sample of transportation of reactor control rod drives in Type A packages.

a. Inspection Scope

This area was inspected to verify that PG&E’s radioactive material transportation program complies with specific requirements of 10 CFR Parts 20, 71, and the Department of Transportation regulations contained in 49 CFR Part 173. The inspectors interviewed PG&E personnel and determined that PG&E had undergone refueling/defueling activities between January 1, 2002, and present, but it had not shipped irradiated control rod drives in Department of Transportation Specification 7A Type A packages.

b. Findings

No findings of significance were identified.

.2 TI 2515/163, Operational Readiness of Offsite Power

The inspectors completed seven samples of operational readiness of offsite power.

a. Inspection Scope

The inspectors collected data pursuant to TI 2515/163, "Operational Readiness of Offsite Power." The inspectors reviewed the licensee's procedures related to General Design Criteria 17, "Electric Power Systems"; 10 CFR 50.63, "Loss of All Alternating Current Power"; 10 CFR 50.65(a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"; and the Technical Specifications for the offsite power system. The data was provided to the Office of Nuclear Reactor Regulation for further review. Documents reviewed for this TI are listed in the attachment.

b. Findings

No findings of significance were identified.

.3 (Closed) Unresolved Item (URI) 05000323/2004005-03: Adequacy of Alarm Procedure for Feedwater Heater Level Control Malfunctions

b. Inspection Scope

The inspectors performed additional inspection associated with this unresolved item to determine any performance issues associated with the operators’ response to the event and the adequacy of the alarm procedure.

c. Findings

Description. On December 23, 2004, operators received on Alarm PK 10-21, Input 646, Feedwater Heater 2-2B high level trip. The Unit 2 shift foreman dispatched the work control lead (senior reactor operator) and turbine building nonlicensed operator to investigate the cause of the alarm. Control room operators then entered Alarm Procedure AR PK 10-21, “Feedwater Heaters High Level Trip,” Revision 4, when the alarm annunciated and took actions to trip the reactor if necessary. The control room operators observed the condensate flow increase as the Heater Drain 2 tank level and main feedwater pump suction pressure decreased. The work control lead was instructed by the control room to investigate the cause of the feedwater heater high level trip alarm and noticed that the level was high out-of-sight and the controlling air pressure to the level control valve was low.

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

The inspectors reviewed the operator response to the event and determined that the operators took appropriate action according to their procedures and training. Procedure OP1.DC11, “Conduct of Operations-Abnormal Plant Conditions,” Revision 25, discussed how the shift foreman has the responsibility to determine the appropriate response to annunciators. The shift foreman directed the work control lead to investigate the level problem with Feedwater Heater 2-2B, which was necessary to determine if the feedwater heater level was out-of-sight high. The work control lead readily identified a controller malfunction as the cause of the feedwater high level and adjusted the controller setpoint to alleviate the level condition. Although conditions existed per AR PK 10-21 for a reactor trip and closure of main steam isolation valves, the control room was not aware of the condition until after the condition was no longer present. Operators were not required to perform procedure steps for conditions that no longer exist unless specified in the procedure.

The inspectors noted that Procedure AR PK 10-21, step 5.1.1, stated that “if flow has not increased, then the high level condition may be due to a malfunction of the level control system,” and “if flow has increased, this could be an indication of a tube leak.” The inspectors determined that these statements in the procedure provided diagnostic information to the operators, namely an increase in condensate flow and a high out-of-sight level on the feedwater heaters as evidence of a feedwater heater tube rupture or a feedwater heater controller malfunction. The inspectors determined that PG&E had not developed a procedural basis for the actions specified by step 5.1.1 that would provide for different responses between a feedwater heater tube rupture and a feedwater level controller malfunction.

Analysis. No performance deficiency was identified; therefore, no safety significance analysis was performed.

Enforcement. No violation of NRC requirements was identified. This unresolved item (URI 05000323/2004005-03: Adequacy of Alarm Procedure for Feedwater Heater Level Control Malfunctions) is closed.

.4 Review of the Institute for Nuclear Power Operations (INPO) Biennial Evaluation

On June 29, 2005, the inspectors reviewed the INPO Evaluation and Assessment Report for PG&E. The inspectors noted that the INPO report was generally commensurate with NRC assessment of performance and that no significant safety issues requiring separate NRC follow-up were identified.

40A6 Management Meetings

Exit Meeting Summary

The resident inspection results were presented on July 5, 2005, to Mr. David Oatley, Vice President and General Manager, Diablo Canyon and other members of PG&E management. PG&E acknowledged the findings presented.

On May 17, 2005, the inspectors discussed the inspection findings on emergency action level and emergency plan changes with Mr. M. Lemke, Manager, Emergency Preparedness. PG&E acknowledged the findings presented.

On May 20, 2005, the inspectors discussed the inspection findings on transportation of reactor control rod drives in Type A packages with Mr. R. Hite, Manager, Radiation Protection. PG&E acknowledged the findings presented.

On May 31, 2005, following the NRC's review of the final grading for this requalification cycle, the inspectors conducted a telephonic exit meeting with Mr. D. Burns, Training Supervisor, and other members of his staff. PG&E acknowledged the findings presented.

The inspectors asked PG&E whether any materials examined during the inspection should be considered proprietary. Copies of proprietary information were reviewed by the inspectors and destroyed at the end of the inspection.

4OA7 Licensee-Identified Violations

The following findings of very low safety significance (Green) were identified by PG&E and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions,” states, in part, that measures be established to assure that conditions adverse to quality, such as nonconformances, are promptly identified and corrected. Contrary to this, from 2001 to the present, Check Valve RHR-2-8742B has shown a degrading trend in backseat leakage due to a minor manufacturing defect. This was identified in PG&E’s CAP as AR A05992204 to be replaced in Refueling Outage 2R13. The check valve has a safety function to fully open, which has not been impacted by the defect. This finding is of very low safety significance because it does not represent a degradation to the safety functions of the RHR system.

- 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions,” states, in part, that measures be established to assure that conditions adverse to quality, such as nonconformances, are promptly identified and corrected. This was identified in PG&E’s CAP as AR A0538530. Contrary to this, from August 2001 to September 2004, PG&E staff noted that RWST leakage had increased to 3 gph, as documented in AR A0538530, but did not identify and correct the source of the leakage. PG&E staff walked down the ECCS systems but was unsuccessful in finding the source of the leakage. In September 2004, PG&E staff planned to review plant work that may have increased RWST leakage from ECCS drain valves. In January 2005, the RWST leakage increased to 6 gph. The inspectors questioned PG&E staff as to the adequacy of their troubleshooting activities to identify the leakage paths and their bases for determining that the leakage was not coming from the RWST but a leaking ECCS drain line. PG&E staff added discussion to AR A0538530 regarding their bases for why they had concluded that the leakage was not coming from the RWST (i.e., past ground water samples did not indicate boric acid, the tank is a concrete tank with a steel liner, and no boric acid observed outside the tank). Subsequently, PG&E staff was able to identify two valves that contributed to a large part of the RWST leakage. These valves were CS-2-21, Containment Spray Pump 2-1 discharge drain line, and RHR-2-8722B, drain line from RHR Heat Exchanger 2-2. Valve RHR-2-8722B is in the post-LOCA recirculation path, but it did not cause the actual adjusted recirculation path leakage to exceed the FSAR Update limit of 1.64 gpm. Both valves have subsequently been replaced, and during the replacement of Valve RHR-2-8722B, maintenance technicians found that Valve RHR-2-8723B was also leaking.

  Using IMC 0609, Appendices A and H, the finding involved an actual bypass of containment, but it screened as very low safety significance since Valves RHR-2-8722B and RHR-2-8723B were not important to the large early release frequency and it drains to a closed drain system (miscellaneous equipment drain tank) where the contents of that tank are filtered and processed through demineralizers.

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
D. Burns, Training Manager, Learning Services
S. Chesnut, Director, Engineering Services
S. David, Manager, Operations
J. Fledderman, Director, Site Services
C. Harbor, Manager, Problem Prevention and Resolution
R. Hite, Manager, Radiation Protection
D. Jacobs, Vice President Nuclear Services
S. Ketelsen, Manager, Regulatory Services
M. Lemke, Manager, Emergency Preparedness
D. Oatley, Vice President and General Manager, Diablo Canyon
P. Roller, Director, Operations Services

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

50-275/2005-003-01	NCV	Failure to Promptly Identify and Correct Diesel Engine Generator Lube Oil Carbonization (Section 1R13)
50-323/2005-003-02	NCV	Failure to Provide Corrective Actions to Prevent Recurrence for Pressurizer Safety Valve Out-of-Tolerance Lift Setpoints (Section 4OA2.1)

Closed

50-275/2003-001-00	LER	Technical Specification 3.8.1, Action B.1, not Met due to Personnel Error (Section 4OA3.1)
50-275/2004-001-00	LER	Steam Generator Tube Plugging due to Stress Corrosion Cracking (Section 4OA3.2)
50-323/2004-001-00	LER	Unplanned Valid Diesel Generator Auto-start during Phase Sequence Check (Section 4OA3.3)

50-275/2004-002-00	LER	Technical Specification 3.0.3 Required Shutdown Due to Technical Specification 3.7.7, "Vital CCW System," Not Met (Section 4OA3.4)
50-323/2004-005-03	URI	Adequacy of Alarm Procedure for Feedwater Heater Level Control Malfunctions (Section 4OA5.2)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather

Procedures

Number	Title	Revision
AR DG13-2-3	High Temperature Room Air Radiator Discharge	0
AR PK 15-05	Ambient Air Temp PPC	16
AR PK 15-09	Electrical Rooms Temp Monitor	25
AR PK 15-10	ESF Equipment Rooms Temp Monitor	16

Section 1R04: Equipment Alignment

Drawings

Number	Title	Sheet	Revision
106714	Component Cooling Water	2	45
107710	Residual Heat Removal	2	27

Procedures

Number	Title	Revision
OP B-2:I	RHR System Alignment Verification for Plant Startup	19
OP F-2:I	Component Cooling Water System - Make Available	25

Section 1R11: Licensed Operator Requalification

Procedures

Number	Title	Revision
CF2.DC1	Configuration Management Plan for the Operator Training Simulator	4
OM14.ID2	Medical Examinations	5
SQA 99-2	Operator Training Simulator Software Quality Assurance Plan	0
TQ2.DC3	Licensed Operator, Non-Licensed Operator, and Shift Technical Advisor Continuing Training Program	13
TQ2.ID4	Training Program Implementation	8
TQ2.ID6	Training Records Management	3

Written Examinations

R0304 Biennial Exam Package 1, First Run, Test 1
R0304 Biennial Exam Package 2, First Run, Test 2
R0304 Biennial Exam Package 8, Week 1, Test 1
R0304 Biennial Exam Package 4, Week 1, Test 2
R0304 Biennial Exam Package 5, Week 2, Test 1
R0304 Biennial Exam Package 6, Week 2, Test 2
R0304 Biennial Exam Package 9, Week 5, Test 1
R0304 Biennial Exam Package 9, Week 5, Test 2

Scenarios

Number	Title	Revision
E2ECA21-A	Faulted S/G [Steam Generator]	13
E2ECA21-B	Faulted S/G	12A
E2ECA21-C	Faulted S/G	11
E3ECA33-A	SGTR [Steam Generator Tube Rupture]	15
E3ECA33-B	SGTR	12
ECA00-B	Loss of all AC	10A
ECA1112-B	Seismic/Loss of ECR [Emergency Coolant Recirculation] /LOCA	11A
FRC12-B	ICC [Inadequate Core Cooling]/Degraded Core Cooling	9
FRH1-A	Loss of Heat Sink	11
FRP1-A	Imminent PTS [Pressurized Thermal Shock]	11A

FRS1-A	ATWS [Anticipated Transient Without Scram]	13

Job Performance Measures (JPMs)

Number	Title	Revision
LJC-005	Isolate a Ruptured VCT [Volume Control Tank]	19
LJC-009	Respond to High Accumulator Pressure	15
LJC-010	Initiate Containment Spray Manually	15
LJC-011	Isolate Ruptured Steam Generator 12	26
LJC-014	Estimate Decay Heat and Heatup Rate	5
LJC-015	Perform a Boron Concentration Change of the RCS Using CVCS [Chemical Volume and Control System]	15/16
LJC-017	Verify Natural Circulation	21
LJC-021	Perform Control Room Actions Prior to Evacuation	22
LJC-026	Manually Isolate Phase A Components - Train A & B Failures	21
LJC -028	Align RHR Pump 12 for Hot Leg Recirculation	13
LJC-035	Check for an Uncontrolled Cooldown of the RCS	11
LJC-041	Respond to an ATWS	17
LJC-044	Start a Reactor Coolant Pump	12
LJC-049	Depressurize the RCS for Steam Generator Backfill	11
LJC-050	Perform RCS Leak Evaluation - Leak Inside Containment	19
LJC-063	Establish Emergency Boration	20
LJC-077	Increase Accumulator Pressure	10
LJC-086	Parallel Diesel Generator 12 to Bus	16
LJC-108	Classify a Steam Generator Tube Rupture	13
LJC-112	Reestablish Charging	16
LJC-132	Determine the Scope of Core Damage	12
LJC-136	Review an Estimated Critical Position	12
LJC-137	Perform a Shutdown Margin Determination	14
LJC-140	Respond to a Circulating Water Pump Alarm	9
LJC-146	Monitor Critical Safety Function Status Trees	10
LJP-003	Perform a Local Start of a Diesel Generator	23

LJP-004	Operate the Containment Hydrogen Recombiners	16
LJP-007	Align 480V Buses for Control from the Hot Shutdown Panel	9
LJP-008	Close a MSIV [Main Steam Isolation Valve] Locally	15
LJP-012	Reset the Turbine Driven Aux Feedwater Pump	13
LJP-013	Open the Reactor Trip Breakers Locally	18
LJP-029	Transfer Pressurizer Heater Group 12 to Backup Power	19
LJP-058	Transfer the TSC [Technical Support Facility] to Vital Power	20
LJP-062	Isolate Dilution Flow Paths	14
LJP-065	Operate AFW in Manual at the Hot Shutdown Panel	20
LJP-068	Reset Bank Alignment for a Misaligned Rod	12
LJP-070	Recover from a Dropped Rod	12
LJP-073	Transfer Rods to the DC Hold Bus	11
LJP-079	Transfer Pressurizer Heater Group 13 to Backup Power	20
LJP-091	Isolate Hydrogen to a Ruptured VCT	7
LJP-095	De-energize SSPS to Block Safety Injection	10
LJP-098	Isolate a 10% Steam Dump Valve	8
LJP-130	Establish Backup Cooling to a Centrifugal Charging Pump	10
LJP-138	Manually Operate the Cardox System	4
LJP-155	Establish Long Term Cooling to a Steam Generator	13
LJP-158	Establish CCW Train Separation	9
LJP-159	Perform an Emergency Purge of the Main Generator	10
LJP-206	Swap ASDR [Auxiliary Steam Drain Receiver] to Other Unit	6
LJP-207	Align Charging Pump Suction from RWST [Refueling Water Storage Tank]	8
LJP-208	Locally Place the RHR Heat Exchangers in Service	5

Simulator Change Requests

00-018
02-068
03-120
04-075
04-123
04-135
04-142
04-146
04-174
05-001
05-014
05-035
05-36

Section 1R14: Personnel Performance Related to Nonroutine Plant Evolutions and Events

Procedures

Number	Title	Revision
OP1.ID3	Reactivity Management Program	0
OP L-4	Normal Operation at Power	63
OP C-3.111	Changing Turbine Load	17
OP E-4.3	Circulating Water Shutdown and Clearing	3

Section 4OA5.2: TI 2515/163-05, Operational Readiness of Offsite Power

Procedures

Number	Title	Revision
OP J-2:VIII	Guidelines for Reliable Transmission Service for DCPP	5
AD7.DC6	On-line Maintenance Risk Management	8
AP-26	Loss of Offsite Power	8
ECA-0.1	Loss of All AC Power Recovery Without SI Required	13A
ECA-0.2	Loss of All AC Power Recovery With SI Required	9

LIST OF ACRONYMS

ADAMS	agency documents access and management system
AR	action request
CAP	corrective action program
CCW	component cooling water
CFR	*Code of Federal Regulations*
DEG	diesel engine generators
ECCS	emergency core cooling system
FSAR	Final Safety Analysis Report
IMC	inspection manual chapter
INPO	Institute for Nuclear Power Operations
JPM	job performance measure
LER	licensee event report
LOCA	loss-of-coolant accident
NCR	nonconformance report
NCV	noncited violation
NOUE	Notification of Unusual Event
NRC	Nuclear Regulatory Commission
PARS	publicly available records system
PG&E	Pacific Gas and Electric Company
RHR	residual heat removal
RWST	refueling water storage tank
URI	unresolved item