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

February 14, 2006

John S. Keenan, Chief Nuclear Officer
Pacific Gas and Electric Company
Mail Code B32
P.O. Box 770000
San Francisco, California 94177-0001

SUBJECT: DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000275/2005005 AND 05000323/2005005

Dear Mr. Keenan:

On December 31, 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 January 12, 2006, with Mr. David Oatley and members of your staff.

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

There were two NRC-identified findings and two self-revealing findings of very low safety significance (Green) identified in this report. These findings involved violations of NRC requirements. In addition, licensee-identified violations which were determined to be of very low safety significance are listed in the report. One additional NRC-identified finding was reviewed under the NRC traditional enforcement process and determined to be a Severity Level IV violation of NRC requirements. Because of their very low risk significance and because they are entered into your corrective action program, the NRC is treating these five findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Diablo Canyon Power Plant.

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

Enclosure:
Inspection Report 05000275/2005005
and 05000323/2005005
w/attachment: Supplemental Information

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| RIV:RI:DRP/B | SRI:DRP/B | C:DRS/PSB | C:DRS/OB | C:DRS/PEB |
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

| | |
|---|---|
| Dockets: | 50-275, 50-323 |
| Licenses: | DPR-80, DPR-82 |
| Report: | 05000275/2005005<br>05000323/2005005 |
| 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<br>Avila Beach, California |
| Dates: | October 1 through December 31, 2005 |
| Inspectors: | T. Jackson, Senior Resident Inspector<br>T. McConnell, Resident Inspector<br>R. Lantz, Senior Emergency Preparedness Inspector<br>R. Kopriva, Senior Project Engineer<br>L. Ricketson, PE, Senior Health Physicist<br>J. Adams, Reactor Inspector<br>L. Ellershaw, PE, Consultant |
| Approved By: | W. B. Jones, Chief, Projects Branch B<br>Division of Reactor Projects |

**TABLE OF CONTENTS**

PAGE

## SUMMARY OF FINDINGS

IR 05000275/2005-005, 05000323/2005-005; 10/1/05 - 12/31/05; Diablo Canyon Power Plant Units 1 and 2; Personnel Performance Related to Nonroutine Plant Evolutions and Events, and Problem Identification and Resolution, Access Control to Radiologically Significant Areas, and Performance Indicator Verification.

This report covered a 13-week period of inspection by resident inspectors and announced inspections in the areas of radiation protection and in-service inspections. Two self-revealing and two NRC- identified, Green, noncited violations were identified. Additionally, a Severity Level IV violation was 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 noncited violation of 10 CFR 50.65(a)(4) was identified for the failure of maintenance personnel to adequately assess and manage the risk associated with maintenance on Startup Transformer 1-1. On November 19, 2005, when maintenance personnel were performing work on Startup Transformer 1-1, they failed to conduct a circuit isolation plan which was a risk management action required by Procedures AD7.DC8, "Work Control," Revision 20 and MA1.DC11, "Risk Assessment," Revision 5A. The circuit isolation plan would have provided an opportunity to identify the potential of disrupting startup power to Unit 2, which occurred as a result of the maintenance activities. This issue was entered into Pacific Gas and Electric Company's corrective action program as Action Request A0652421.

  The finding was greater than minor because it is related to Inspection Manual Chapter 0612, Appendix B, Section 3(5)(I), in that maintenance personnel failed to fully implement Procedures AD7.DC8 and MA1.DC11, which called for a circuit isolation plan for medium- to high-risk maintenance activities as a risk management action. The finding affected the Mitigating Systems Cornerstone. Using Inspection Manual Chapter 0609, Appendix K, "Maintenance Risk Assessment and Risk Management Significance Determination Process, Flowchart 2 - Assessment of Risk Management Actions, the incremental core damage probability was less than 1E-6 and the incremental large early release frequency was less than 1E-7. The finding was assessed as having very low safety significance. The cause of the finding is related to the cross-cutting element of human performance in that maintenance personnel failed to follow procedures (Section 1R14).

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified for the failure of operations personnel to properly implement Procedure OP B-3B:I, "Accumulators - Fill and Pressurize," Revision 23. On November 27, 2005, operators failed to correctly align valves according to Procedure OP B-3B:I in order to fill Safety Injection Accumulator 1-3. As a result, the safety injection pumps injected into the reactor coolant system causing the pressurizer heatup rate to be exceeded and contributing to the safety injection discharge header pressurization due to perturbation of check Valve SI-1-8948B. This violation was entered into Pacific Gas and Electric Company's corrective action program as Action Request A0653564.

  The finding is greater than minor because it is associated with the Mitigating System Cornerstone attribute of configuration control and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Inspection Manual Chapter 0609, "Significance Determination Process," Appendix G, Checklist 4, the finding did not require quantitative screening. Therefore, the finding was assessed as having very low safety significance. The cause of the finding is related to the crosscutting element of human performance in that operations personnel did not follow procedures (Section 1R14).

- Green. An NRC-identified noncited violation of 10 CFR Part 50, Criterion XVI, was identified for the failure to promptly correct emergency core cooling system check valve back-leakage. Since 2000, Units 1 and 2 have experienced emergency core cooling system check valve back-leakage. Pacific Gas and Electric Company has failed to adequately take into consideration industry experience and provide for timely corrective actions regarding emergency core cooling system check valve back-leakage and its potential to cause gas-binding of emergency core cooling system pumps and/or water hammer of emergency core cooling system piping. This issue was entered into Pacific Gas and Electric Company's corrective action program as Action Requests A0526037 and A0610421.

  The finding is greater than minor because it is associated with the Mitigating Systems Cornerstone attribute of equipment performance and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using Inspection Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it did not represent an actual loss of safety function, represent an actual loss of 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. The cause of the finding is related to the crosscutting element of problem identification and resolution in that Pacific Gas and Electric Company did not adequately evaluate and implement timely corrective actions to emergency core cooling system check valve back-leakage (Section 4OA2.2).

Cornerstone: Emergency Preparedness

- Severity Level IV. The inspector identified an noncited violation of 10 CFR 50.9 because Pacific Gas and Electric Company failed to provide complete and accurate information in a submittal of data for the emergency preparedness drill and exercise performance indicator. Specifically, Pacific Gas and Electric Company staff failed to identify three missed opportunities for emergency notification accuracy during the second calendar quarter of 2005. Pacific Gas and Electric Company took prompt action to correct the second quarter data, which resulted in the drill and exercise performance indicator color to cross from GREEN to WHITE. Pacific Gas and Electric Company also initiated a 100 percent review of the second and third quarter drill and exercise performance indicator data and discovered one additional administrative error in the third quarter performance indicator data, which had been previously evaluated, but not yet reported to the NRC. Pacific Gas and Electric Company had previously initiated a root cause evaluation in its corrective action program to determine the reason for the declining indicator and, subsequently, initiated another root cause evaluation to determine the reason for the failure to adequately evaluate and report the performance indicator data. The finding also had human performance crosscutting aspects in that the reviews that were performed were not adequate to identify the actual failures that had occurred.

  Because this issue affected the NRC’s ability to perform its regulatory function, it was evaluated using the traditional enforcement process. Supplement 7, Section D.3, of the NRC Enforcement Policy describes this finding as a Severity Level IV violation. The issue is significant because it indicates a declining trend in the attention to detail shown by senior licensed operators in performing emergency notifications to the state and local authorities. This issue is documented in Pacific Gas and Electric Company's corrective action program as Nonconformance Report N0002200 (Section 4OA1).

Cornerstone: Occupational Radiation Safety

- Green. The inspectors identified an noncited violation of 10 CFR 20.1902 for a failure of Pacific Gas and Electric Company to post a radiation area. Specifically, Pacific Gas and Electric Company did not post an area within Vault 26 in which the radiation dose rates were approximately 30 millirem per hour at 30 centimeters from the surfaces of radioactive material storage containers. The finding was entered into Pacific Gas and Electric Company’s corrective action program as Action Request A0652226 and planned corrective action were still being evaluated. The finding had crosscutting aspects in the area problem identification and resolution (corrective actions), in that a similar violation was previously identified in Inspection Report 050000275; 323/2002004.

The finding was more than minor because it was associated with one of the cornerstone attributes (exposure control and monitoring) and the finding affected the Occupational Radiation Safety Cornerstone objective, in that uninformed workers could unknowingly accrue additional radiation dose. The inspector determined that the finding had no more than very low safety significance because: (1) it did not involve ALARA planning and controls, (2) there was no personnel overexposure, (3) there was no substantial potential for personnel overexposure, and (4) the finding did not compromise Pacific Gas and Electric Company's ability to assess dose (Section 2OS1).

B. Licensee-Identified Violations

Violations of very low safety significance, which have been identified by Pacific Gas and 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 Power Plant Unit 1 began this inspection period at 100 percent power. On October 15, 2005, Unit 1 was curtailed to 93 percent power due to the loss of hydrazine injection into the secondary feedwater system. Unit 1 returned to 100 percent power following the restoration of hydrazine on the same day. On October 22, Unit 1 was curtailed to 23 percent power as a precaution due to high storm ocean swells.

On October 23, 2005, operators commenced a Unit 1 reactor shutdown for Refueling Outage 1R13 and entered Mode 3 (Hot Standby). Operators initiated a plant cooldown and entered Mode 4 (Hot Shutdown) on October 23 and Mode 5 (Cold Shutdown) on October 24. On October 28, Unit 1 entered Mode 6 (Refueling) when maintenance personnel de-tensioned the reactor vessel head. Operators commenced core offload on October 30 and completed core offload on November 1. Unit 1 remained de-fueled until November 17 when Unit 1 entered Mode 6 as a result of operators reloading fuel into the reactor vessel. Unit 1 entered Mode 5 on November 22 when maintenance personnel tensioned the reactor vessel head. Operators began increasing reactor coolant temperature, and Unit 1 entered Mode 4 on November 26. Operators continued to increase reactor coolant temperature, and Unit 1 entered Mode 3 on November 28. On November 29, operators commenced a reactor startup, and Unit 1 reached Mode 2 (Startup). Operators continued to increase reactor power, and Unit 1 entered Mode 1 (Power Operations) on December 2. On December 3, the Unit 1 main generator was paralleled to the grid; ending Refueling Outage 1R13. Unit 1 reached 100 percent power on December 8.

On December 20, 2005, Unit 1 was curtailed to 25 percent power as a precaution due to high ocean swells. Unit 1 was returned to 100 percent power on December 21. Unit 1 remained at 100 percent power for the duration of the inspection period.

Diablo Canyon Power Plant Unit 2 began this inspection period at 100 percent power. On October 1, 2005, Unit 2 was curtailed to 87 percent power to support grid maintenance. Following completion of this maintenance activity, Unit 2 was returned to 100 percent power on October 2. On October 22, Unit 2 was curtailed to 23 percent power as a precaution due to high ocean swells. Unit 2 was returned to 100 percent power on October 24. On November 9, Unit 2 was curtailed to approximately 99 percent power for replacement of a feedwater heater valve. Following valve replacement, Unit 2 was returned to 100 percent power on November 12. On December 20, Unit 2 was curtailed to 25 percent power as a precaution due to high ocean swells. Unit 2 was returned to 100 percent power on December 21. 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 completed a review of Pacific Gas and Electric Company's (PG&E) readiness of seasonal susceptibilities involving extreme low temperatures. The inspectors: (1) reviewed plant procedures, the Final Safety Analysis Report (FSAR) Update, and Technical Specifications (TS) to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the one system listed below to ensure that adverse weather protection features (heat tracing, space heaters, weatherized enclosures, etc.) were sufficient to support operability, including the ability to perform safe shutdown functions; (3) evaluated operator staffing levels to ensure PG&E could maintain the readiness of essential systems required by plant procedures; and (4) reviewed thecorrective action program to determine if PG&E identified and corrected problems related to adverse weather conditions.

- December 22, 2005: Units 1 and 2, Vital Batteries

Documents reviewed by the inspectors included:

- Procedure Action Request (AR) PK15-09, “Electrical Rooms Temp Monitor,” Revision 26
- 
- Design Criteria Memorandum S-67, “125 and 250V DC System,” Revision 2

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

Partial System Walkdowns

a. Inspection Scope

The inspectors: (1) walked down portions of the below listed risk-important system and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walk down to the FSAR Update and CAP to ensure problems were being identified and corrected.

- October 7, 2005: Unit 1, Auxiliary Saltwater Pump 1-1

Documents reviewed by the inspectors included:

- Drawing 106717, “Saltwater,” Sheet 7, Revision 132
- Drawing 106717, “Saltwater,” Sheet 7A, Revision 138

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Inspection

a. Inspection Scope

The inspectors walked down the two below listed plant areas to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional and that access to manual actuators was unobstructed; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features and that the compensatory measures were commensurate with the significance of the deficiency; and (7) reviewed the FSAR Update to determine if PG&E identified and corrected fire protection problems.

- November 7, 2005: Unit 1, Containment Fire Zones 1A, 1B, and 1C
- November 8, 2005: Unit 1, 154 foot Auxiliary Building, Detection Zone A-13

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

Annual External Flooding

a. Inspection Scope

The inspectors: (1) reviewed the FSAR Update, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving external flooding; (2) reviewed the FSAR Update and CAP to determine if PG&E identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of (a) sump pumps, (b) level alarm circuits, (c) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down the one below listed area to verify the adequacy of: (a) equipment seals located below the floodline, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

- December 28, 2005: Units 1 and 2, Turbine Building Louvers

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed PG&E's programs, verified performance against industry standards, and reviewed critical operating parameters and maintenance records for Component Cooling Water Heat Exchangers 1-1 and 1-2. The inspectors verified that : (1) performance tests were satisfactorily conducted for heat exchangers/heat sinks and reviewed for problems or errors; (2) PG&E utilized the periodic maintenance method outlined in EPRI NP-7552, "Heat Exchanger Performance Monitoring Guidelines;" (3) PG&E properly utilized biofouling controls; (4) PG&E's heat exchanger inspections adequately assessed the state of cleanliness of their tubes, and (5) the heat exchanger was correctly categorized under the Maintenance Rule.

Documents reviewed by the inspectors included Procedure PEP M-234, "CCW Heat Exchanger Performance Test," Revision 9.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

Inspection Procedure 71111.08 requires a minimum sample size of four (as identified in Sections 02.01, 02.02, 02.03, and 02.04).

02.01: Performance of Nondestructive Examination Activities Other Than Steam Generator Tube Inspections, Pressurized Water Reactor Vessel Upper Head Penetration Inspections, Boric Acid Corrosion Control

a. Inspection Scope

The inspection procedure requires the review of nondestructive examination activities consisting of two or three different types (i.e., volumetric, surface, or visual). The inspectors observed the performance of ultrasonic examinations (volumetric) on eight reactor vessel upper head penetration nozzles and radiographic examinations (volumetric) on two emergency core cooling system pipe welds. In addition, the inspectors observed three liquid penetrant examinations (surface) performed on residual heat removal system components and reviewed liquid penetrant reports of two examinations performed on emergency core cooling system pipe welds. The table below identifies the above examinations, which were conducted using three methods and two different examination types.

| Component | Identity | Examination Type | Examination Method |
|---|---|---|---|
| Reactor Vessel Upper Head Penetration Nozzles | 30,31,33,36,37,43, 57, and the vent line weld | Volumetric | Ultrasonic |
| Emergency Core Cooling System Suction Void Header | Welds WIC 1 and WIC 2 | Volumetric | Radiography |
| Residual Heat Removal System Pipe Support Lug welds | 58N-49R (2 each) | Surface | Liquid Penetrant |
| Residual Heat Removal System Pipe Support Bracket | 58N-52A | Surface | Liquid Penetrant |
| Emergency Core Cooling System Pipe-To-Elbow welds | Welds FW 25 and FW 26 | Surface | Liquid Penetrant |

For each of the nondestructive examination activities reviewed, the inspectors verified that the examinations were performed in accordance with the specific site procedures and the applicable American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) requirements.

During review of each examination, the inspectors verified that appropriate nondestructive examination procedures were used, examinations and conditions were as specified in the procedure, and test instrumentation or equipment was properly calibrated and within the allowable calibration period. The inspectors also verified the nondestructive examination certifications of the personnel who performed the above ultrasonic and radiographic examinations. Finally, the inspectors observed that indications identified during the ultrasonic and radiographic examinations were dispositioned in accordance with the ASME qualified nondestructive examination procedures used to perform the examinations.

In addition to observation of ultrasonic examinations performed on the eight reactor vessel upper head penetration nozzles identified in the table above, the inspectors observed portions of the ultrasonic examination data analysis associated with the following nine nozzle penetrations: 17, 21, 27, 31, 34, 35, 36, 40, and 74.

The inspection procedure requires review of one or two examinations with recordable indications that were accepted for continued service to ensure that the disposition was made in accordance with the ASME Code. The inspectors reviewed AR A0650500, which documented identification of a flaw in the Loop 3 cold leg nozzle-to-safe end Weld WIB-RC-3-18(SE). The flaw was identified and documented on November 6, 2005, during an ultrasonic (volumetric) examination. PG&E's contractor (WesDyne International) performed an indication sizing assessment on November 7, 2005, using Procedure PDI-ISI-254-SE, "Flaw Sizing," Revision 2. The result of the flaw sizing evaluation, which showed that the flaw was acceptable, supported continued Unit 1 operation. The inspectors verified that the evaluation was performed in accordance with the 1989 Edition of the ASME Code, Section XI, Tables IWB-3514-2 and IWB-3514-1, which provide the specific rules for the performance of such evaluations.

One other instance was identified in which an indication was detected during liquid penetrant (surface) examination of residual heat removal pipe support Bracket 58N-52A. The 0.2 inch linear indication was evaluated in accordance with ASME Code requirements and was found to meet the specified acceptance standards. PG&E personnel documented the size and location of the indication in the liquid penetrant examination report.

The inspection procedure further requires verification of one to three welds on Class 1 or 2 pressure boundary piping to ensure that the welding process and welding examinations were performed in accordance with the ASME Code. The inspectors verified through record review that welding and subsequent examinations performed on the Class 2 emergency core cooling system suction void header Welds WIC 1, WIC 2, FW 25, and FW 26 were performed in accordance with Sections V, IX, and XI of the 1989 Edition of the ASME Code. This included review of welding material issue slips to establish that the appropriate welding materials had been used, verification of welder qualifications, verification that the welding procedure specification (WPS-51) had been properly qualified, and verification that the applicable nondestructive examination procedures used to perform the examinations had been qualified. The inspectors also verified that weld filler materials were properly stored and controlled and that proper administrative controls were being implemented with respect to issuance and return of weld filler materials.

The inspectors completed one sample under this section.

b. Findings

No findings of significance were identified.

02.02: Reactor Vessel Upper Head Penetration Inspection Activities

The inspection procedure requires this section to be performed after completion of Temporary Instruction (TI) 2515/150. The TI had not been completed at the time of this inspection; therefore, this section was not performed.

02.03: Boric Acid Corrosion Control Inspection Activities (Pressurized Water Reactors)

a. Inspection Scope

The inspectors evaluated the implementation of PG&E's boric acid corrosion control program for monitoring degradation of those systems that could be deleteriously affected by boric acid corrosion.

The inspection procedure requires review of a sample of boric acid corrosion control walkdown visual examination activities through either direct observation or record review. The inspectors reviewed the documentation associated with PG&E's boric acid corrosion control walkdown as specified in Procedure ER1.ID2, "Boric Acid Corrosion Control Program," Revision 1. Samples of documented visual inspection records and filmed results of inspections of components and equipment were also reviewed by the inspectors.

Additionally, the inspectors performed independent observations of piping containing boric acid during walkdowns of the containment building and the auxiliary building.

The inspection procedure requires verification that visual inspections emphasize locations where boric acid leaks can cause degradation of safety significant components. The inspectors verified through direct observation and program/record review that PG&E's boric acid corrosion control inspection efforts are directed towards locations where boric acid leaks can cause degradation of safety-related components.

The inspection procedure requires both a review of one to three engineering evaluations performed for boric acid leaks found on reactor coolant system piping and components, and one to three corrective actions performed for identified boric acid leaks. The inspectors reviewed engineering evaluations associated with ARs A0649000, A0649209, and A0649215, which addressed boric acid leaks identified on a body-to-bonnet bolted connection on a valve in the safety injection system and valve packing leaks on valves in the reactor coolant system and the safety injection system. The evaluations appropriately addressed the causes and corrective actions. Additionally, the inspectors reviewed ARs A0649207 and A0649959 that identified minor boric acid leaks that did not require formal engineering evaluations to effect corrective actions.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

02.04: Steam Generator Tube Inspection Activities

a. Inspection Scope

The inspection procedure specified performance of an assessment of in-situ screening criteria to assure consistency between assumed nondestructive examination flaw sizing accuracy and data from the Electric Power Research Institute (EPRI) examination technique specification sheets. It further specified assessment of appropriateness of tubes selected for in situ pressure testing, observation of in situ pressure testing, and review of in situ pressure test results.

By letter dated October 28, 2005, the NRC issued Amendment 182 to Facility Operating License DPR-80 and Amendment 184 to Facility Operating License DPR-82 for the Diablo Canyon Power Plant, Units 1 and 2, respectively. These amendments consist of changes to the TS and allow use of the steam generator tube W* (W-star) alternate repair criteria for indications in the Westinghouse explosive tube expansion (WEXTEX) region on a permanent basis. The W* alternate repair criteria allows axial primary stress corrosion cracking in the WEXTEX region to remain in service provided the indication remains below the bottom of the WEXTEX transition during the next operating cycle. The length of the tube required to be inspected within the hot leg tubesheet is referred to as the W* distance. While implementation of the W* alternate repair criteria eliminated the current W* in-situ testing program, other requirements for in-situ testing remain.

At the time of this inspection, no conditions had been identified that warranted in-situ pressure testing. The inspectors did, however, review PG&E's report, Steam Generator Degradation Assessment for Diablo Canyon Unit 1 Refueling Outage 1R13, October 2005, Revision 0, dated October 28, 2005, and compared the in-situ test screening parameters to the guidelines contained in the EPRI document, In Situ Pressure Test Guidelines, Revision 2. This review determined that the remaining screening parameters were consistent with the EPRI guidelines.

In addition, the inspectors reviewed both PG&E site-validated and qualified acquisition and analysis technique sheets used during this refueling outage and the qualifying EPRI examination technique specification sheets to verify that the essential variables regarding flaw sizing accuracy, tubing, equipment, technique, and analysis had been identified and qualified through demonstration. The inspector-reviewed acquisition technique and analysis technique sheets are identified in the Attachment.

The inspection procedure specified comparing the estimated size and number of tube flaws detected during the current outage against the previous outage operational assessment predictions to assess the licensee's prediction capability. The inspectors compared the previous outage operational assessment predictions with the flaws identified thus far during the current steam generator tube inspection effort. Compared to the projected damage mechanisms identified by PG&E, the number of identified indications fell within the range of prediction and were quite consistent with predictions. The number of circular outside diameter stress corrosion cracking flaws, however, was higher than predicted. Thus, the number of tubes identified for plugging was higher than expected. As a result, PG&E placed Steam Generators 1-1 and 1-2 in TS C-3 category based on the total number of defective tubes identified during eddy current testing. The consequence of entering C-3 category requires an increase in tube sample size for eddy current examination, but since PG&E was already performing eddy current examinations on 100 percent of the available tubes, it had no impact on sample size. The inspectors determined that the flaw degradation severity levels found, thus far, were well within the predicted expectations.

The inspection procedure specified confirmation that the steam generator tube eddy current test scope and expansion criteria meet TS requirements, EPRI guidelines, and commitments made to the NRC. The inspectors evaluated the recommended steam generator tube eddy current test scope established by TS requirements and the Diablo Canyon Power Plant Power Plant degradation assessment report. The inspectors compared the recommended test scope to the actual test scope and found that PG&E had accounted for all known flaws and had, as a minimum, established a test scope that met TS requirements, EPRI guidelines, and commitments made to the NRC.

The inspection procedure specified, if new degradation mechanisms were identified, verification that the licensee fully enveloped the problem in its analysis of extended conditions including operating concerns and had taken appropriate corrective actions before plant startup. To date, the eddy current test results had not identified any new degradation mechanisms.

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

The inspection procedure further requires verification that repair processes being used were approved in the TS. At the time of this inspection, it was estimated that a total of approximately 108 tubes would be plugged using mechanically rolled plugs, none of which had been installed. The inspectors verified that this particular plugging operation was an NRC-approved repair process.

The inspection procedure also requires confirmation of adherence to the TS plugging limit, unless alternate repair criteria have been approved. The inspection procedure further requires determination whether depth-sizing repair criteria were being applied for indications other than wear or axial primary water stress corrosion cracking in dented tube support plate intersections. The inspectors determined that the TS plugging limits were being adhered to (i.e., 40 percent maximum through-wall indication).

If steam generator leakage greater than 3 gallons per day was identified during operations or during post shutdown visual inspections of the tubesheet face, the inspection procedure requires verification that the licensee had identified a reasonable cause based on inspection results and that corrective actions were taken or planned to address the cause for the leakage. The inspectors did not conduct an assessment because this condition did not exist.

The inspection procedure requires confirmation that the eddy current test probes and equipment were qualified for the expected types of tube degradation and an assessment of the site-specific qualification of one or more techniques. The inspectors observed portions of eddy current tests performed on the tubes in Steam Generators 1-1, 1-2, 1-3, and 1-4. During these examinations, the inspectors verified that: (1) the probes appropriate for identifying the expected types of indications were being used, (2) probe position location verification was performed, (3) calibration requirements were adhered, and (4) probe travel speed was in accordance with procedural requirements. The inspectors performed a review of site-specific qualifications of the techniques being used. These are identified in the Attachment.

If loose parts or foreign material on the secondary side were identified, the inspection procedure specified confirmation that the licensee had taken or planned appropriate repairs of affected steam generator tubes and that they inspected the secondary side to either remove the accessible foreign objects or perform an evaluation of the potential effects of inaccessible object migration and tube fretting damage. During this inspection, three small pieces of wire (possibly from a wire brush) were identified in Steam Generator 1-2 during foreign object search and retrieval (FOSAR) inspections. These were removed.

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

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved reactor coolant system leakage, an earthquake, a loss-of-coolant accident, and a radiological release from the containment.

Documents reviewed by the inspectors included Lesson ES 1213A, "LOCA," Revision 12.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the five below listed maintenance activities to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the Maintenance Rule, 10 CFR Part 50, Appendix B, and the TS.

- October 5, 2005: Units 1 and 2, fan belts,
- December 12, 2005: Unit 1, Startup Transformer 1-1 Load Tap Changer,
- December 16, 2005: Unit 1, Seismic Monitor ENSTA3 and Trip Device Y-203,
- December 16, 2005: Units 1 and 2, Auxiliary Transformer 1-1 oil analysis,

Documents reviewed by the inspectors are listed in the Attachment.

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

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

.1 Risk Assessments and Management of Risk

a. Inspection Scope

The inspectors reviewed the below listed assessment activities to verify: (1) performance of risk assessments when required by 10 CFR 50.65(a)(4) and PG&E procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that PG&E recognizes, and/or enters as applicable, the appropriate risk category according to the risk assessment results and PG&E procedures; and (4) PG&E identified and corrected problems related to maintenance risk assessments.

- October 6, 2005: Unit 1, Component Cooling Water Pump 1-1 maintenance and 500 kV Breaker 532 replacement

Documents reviewed by the inspectors included Procedure AD7.DC6, "On-line Maintenance Risk Management," Revision 9.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Emergent Work

f. Inspection Scope

The inspectors: (1) verified that PG&E performed actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems and barrier integrity systems; (2) verified that emergent work-related activities such as troubleshooting, work planning/scheduling, establishing plant conditions, aligning equipment, tagging, temporary modifications, and equipment restoration did not place the plant in an unacceptable configuration; and (3) reviewed the FSAR Update to determine if PG&E identified and corrected risk assessment and emergent work control problems.

- October 24, 2005: Unit 1, Vital Inverter IY-13 trip

- November 6, 2005: Unit 2, spent fuel pool level drop

- November 23, 2005: Unit 2, Diesel Engine Generator 2-3 lube oil heater contactor failure and pre-circulating lube oil pump vibration

Documents reviewed by the inspectors are listed in the Attachment.

The inspectors completed three samples.

b. Findings

Section 4OA7 discusses findings of very low safety significance identified by PG&E.

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

a. Inspection Scope

The inspectors: (1) reviewed operator logs, plant computer data, and/or strip charts for the below listed evolutions to evaluate operator performance in coping with non-routine events and transients; (2) verified that operator actions were in accordance with the response required by plant procedures and training; and (3) verified that PG&E has identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the non-routine evolutions sampled.

- October 12, 2005: Unit 1, Operators and engineers observed several nuclear instrument spikes near the end of core life, as well as a half-step inward on the controlling group control rods.

- November 19, 2005: Unit 2, While performing maintenance on Startup Transformer 1-1, Sudden Pressure Relay 80MRST11 was actuated and resulted in the opening of Breaker 212 in the 230 kV switchyard and the loss of startup power to Unit 2.

- November 27, 2005: While performing a refill of Safety Injection Accumulator 1-1 using the safety injection system pumps, the operators inadvertently injected into the reactor coolant system.

Documents reviewed by the inspectors are listed in the Attachment.

The inspectors completed three samples.

b. Findings

(1) Loss of Startup Power to Unit 2

Introduction: A Green, self-revealing NCV was identified for the failure to adequately assess and manage the risk associated with maintenance on Startup Transformer 1-1, as required by 10 CFR 50.65(a)(4). Specifically, PG&E failed to conduct a circuit isolation plan, which was a risk management action required by procedures. As a result, startup power to Unit 2 was lost.

Description: On November 19, 2005, maintenance technicians were performing a functional test of Relay 80MRST11 when a sudden pressure relay trip alarmed on Startup Transformer 1-1 and Breaker 212, which provides startup power to both units, tripped open in the 230 kV switchyard. This resulted in a loss of startup power to Unit 2. Unit 1 was not affected because startup power was cleared for that unit. The Unit 2 diesel engine generators auto-started on the loss of startup power but did not load because the associate vital buses remained energized. The Unit 2 diesel generator engines were subsequently shutdown by the operators. PG&E staff determined that Sudden Pressure Relay 80MRST11 was not adequately isolated from the protective circuit for Startup Transformer 1-1. Therefore, when the maintenance technician tested the relay, a signal was sent to Breaker 212 to open.

The apparent cause was identified as a human performance error in failing to review applicable drawings and take appropriate actions prior to relay actuation. Additionally, the inspectors recognized that Procedure AD7.DC8, "Work Control," Revision 20, stated that any work with a performance frequency of greater than quarterly shall be considered as "non-routine" and should be evaluated against Procedure MA1.DC11, "Risk Assessment," Revision 5A. Procedure MA1.DC11 required that a circuit isolation plan be developed for work that imposed medium- to high -risk. The use of the circuit isolation plan would have added an opportunity to identify the potential impact to Unit 2 startup power.

Analysis: The performance deficiency associated with this finding involved the failure to adequately assess and manage the risk associated with maintenance on the Startup Transformer 1-1 relay. The finding was greater than minor because it is related to IMC 0612, Appendix B, Section 3(5)(I), for a failure to implement any prescribed significance compensatory measures or failure to effectively manage those issues. In this case, maintenance personnel failed to fully implement Procedures AD7.DC8 and MA1.DC11, which called for a circuit isolation plan for medium- to high-risk maintenance activities as a risk management action. The finding affected the Mitigating Systems Cornerstone. Using IMC 0609, Appendix K, "Maintenance Risk Assessment and Risk Management Significance Determination Process, Flowchart 2 - Assessment of Risk Management Actions," the incremental core damage probability was less than 1E-6 and the incremental large early release frequency was less than 1E-7. The finding was assessed as having very low safety significance. The cause of the finding is related to the crosscutting element of human performance in that maintenance personnel failed to follow procedures.

Enforcement: 10 CFR 50.65(a)(4) requires, in part, that before performing maintenance activities, the licensee shall assess and manage the risk that may result from the proposed maintenance activities. Contrary to this, on November 19, 2005, maintenance personnel failed to adequately assess and manage the risk associated with protective relay maintenance on Startup Transformer 1-1, which resulted in the loss of startup power to Unit 2. Specifically, maintenance personnel failed to implement a risk management action (circuit isolation plan), which would have provided an opportunity to identify the potential loss of startup power to Unit 2. The corrective actions to restore compliance included revision of the protective relay work orders requiring circuit isolation plans, a review of work involving startup transformers, and additional training on protective relay work. Because the finding is of very low safety significance and has been entered into the CAP as AR A0652421, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 50-275/05-05-01, Failure to Adequately Assess and Manage Risk Associated With Startup Transformer 1-1 Maintenance.

- Inadvertent Injection Into the Reactor Coolant System

Introduction: A Green, self-revealing NCV of Technical Specifications 5.4.1.a was identified for improper implementation of Operating Procedure OP B-3B:I, "Accumulators- Fill and Pressurize," Revision 23. The failure to follow Procedure OP B-3B:I resulted in exceeding the cooldown rate for the pressurizer and contributing to safety injection discharger header pressurization due to perturbation of check Valve SI-1-8948B.

Description: On November 27, 2005, operators were using Procedure OP B-3B:I to align the safety injection system for filling Accumulator 1-3 using the safety injection pumps. Procedure OP B-3B:I, step 6.1, directs the operators to perform step 6.7 if primary plant pressure is at or near normal operating pressure. Contrary to this, at the time of the evolution primary plant pressure was lower than normal operating pressure. Operators aligned the safety injection system according to Step 6.7, and the resultant alignment caused water to be transferred into the reactor coolant system rather than Accumulator 1-3. The increase in primary plant inventory raised pressurizer level from 40 to 72 percent, or approximately 1800 gallons. The high pressurizer level alarm was received at the 70 percent level setpoint. As a result of the change in level, the pressurizer liquid space temperature decreased from 539EF to 370EF in 15 minutes. The operators then energized all of the pressurizer heaters and restored the pressurizer liquid temperature to the normal steady state temperature of 530EF over the next hour. Equipment Control Guideline 7.5 specified a pressurizer heat-up limit of 100EF in one hour. This heat-up was exceeded in approximately 15 minutes when liquid temperatures reached 471EF.

Additionally, as a result of the safety injection system misalignment, the first off and second off emergency core cooling system check valves had become unseated. Valve SI-1-8948B was later identified to be leaking. This leakage from the primary to the safety injection system had two primary effects; Accumulators 1-1 and 1-3 boron concentration was being diluted and the safety injection header pressure was slowly being pressurized. These conditions required additional procedures to be changed and implemented to assure that boron concentration remained within TS limits, and the safety injection header pressure did not pressurize to a point where the header relief valves would actuate at 1750 psig. These conditions are identified in PG&E's CAP by AR's A0653564, A0610421, and A0653644. Further discussion of historical check valve performance is discussed in this report under Section 4OA2, "Identification and Resolution of Problems."

Analysis: The performance deficiency associated with this finding involved operations personnel failing to perform the appropriate sections of Procedure OP B-3B:I with regard to existing plant conditions. The finding is greater than minor because it was associated with the Mitigating System Cornerstone attribute of configuration control and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using IMC 0609, "Significance Determination Process," Appendix G, Checklist 4, the finding did not require quantitative screening. Therefore, the finding was assessed as having very low safety significance. The cause of the finding is related to the crosscutting element of human performance in that operations personnel did not follow procedures.

Enforcement: TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Appendix A, “Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors,” of Regulatory Guide 1.33, “Quality Assurance Program Requirements (Operation),” dated February 1978. Regulatory Guide 1.33, Appendix A, Section 3.d requires procedures for emergency core cooling systems. Procedure OP B-3B:I, “Accumulators- Fill and Pressurize,” Revision 23, required that operators go to Step 6.7 only if filling accumulators from about normal pressure and level. Contrary to this, on November 27, 2005, operators failed to implement the steps prior to Step 6.7 to properly align the safety injection system when reactor coolant system pressure and level were not at normal values. Improper alignment of the safety injection system allowed injection into the reactor coolant system; exceeding the pressurizer heatup limits and contributing to Valve 8948B back-leakage. PG&E has initiated actions to determined the apparent cause and appropriate corrective actions. Because this finding is of very low safety significance and it was entered into PG&E’s CAP, it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 50-275/05-05-02, Failure to Properly Implement Procedure for Safety Injection System Operation.

1R15 Operability Evaluations (71111.15)

m. Inspection Scope

The inspectors: (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the FSAR Update and design bases documents to review the technical adequacy of the operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any TS; (5) used the SDP to evaluate the risk significance of degraded or inoperable equipment; and (5) verified that PG&E has identified and implemented appropriate corrective actions associated with degraded components.

- October 5, 2005: Units 1 and 2, Fire protection and the potential loss of reactor coolant pump seal cooling

- October 5, 2005: Units 1 and 2, Evaluation of Information Notice 2005-04, "Non-conservatism Leakage Detection Sensitivity"

- October 31, 2005: Unit 1, Auxiliary Feedwater Pump 1-2 inboard motor bearing oil leak

- October 31, 2005, Hannifin check valves

- November 1, 2005: Unit 2, Particulate matter found in Centrifugal Charging Pump 2-2 lube oil system

- November 4, 2005: Unit 1, Structural beam damage at Main Steam Lead 4 pipe restraint

- November 4, 2005: Unit 1, Startup transformer load tap changer in manual

- November 8, 2005: Unit 1, Source Range Detector N31 intermittent alarm for loss of detector voltage

- November 9, 2005: Unit 1, Motor-operated Valve FW-1-LCV-107 failed to shut on demand

- December 15, 2005: Unit 1 and 2, TS Limiting Condition of Operation 3.4.1 TAVG limit inconsistent with current analysis

- December 15, 2005: Unit 1 and 2, Doppler acoustic sounder not functioning

Documents reviewed by the inspectors are listed in the Attachment.

The inspectors completed eleven samples.

b. Findings

Introduction: An unresolved item was identified to further evaluate the corrective actions that were implemented following failures of auxiliary feedwater valve level control valves.

Description: Valve FW-1-LCV-107 is a discharge valve from the turbine-driven auxiliary feedwater pump to Steam Generator 1-2. Its safety function is to close in order to isolate auxiliary feedwater flow to that steam generator if it is faulted.

On November 3, 2005, operators were stroking Valve FW-1-LCV-107 per Procedure STP V-2U2D, "Exercising S/G No. 2 AFW Supply Valves LVC-107 and LCV-111," Revision 4, after valve packing had been replaced. Valve FW-1-LCV-107 had been stroked open and closed successfully from the control room. Operational control for the valve was then transferred to the hot shutdown panel, and the valve was opened, but not able to be shut. Several other attempts to shut the valve from the hot shutdown panel and the control room were also unsuccessful. PG&E staff later determined that the Limitorque valve actuator's torque limit switch exhibited high resistance across its contacts. This Limitorque actuator (Model SMB-000) used leaf-spring contacts in a non-wiping configuration for the torque switch. A visual inspection of the contacts revealed some particulates and dust laying about the contact fingers. Maintenance records indicated that the contacts were burnished prior to valve packing maintenance, providing an opportunity for maintenance to introduce the loose material into the valve actuator.

Inspectors observed that the same torque limit switch had prevented Valve FW-1-LCV-107 from operating 14 months previously. This failure, as described in AR A0616766, also occurred after preventive maintenance to clean and lubricate the valve actuator on August 19, 2004. The apparent cause in AR A0616766 stated "the DCPP [Diablo Canyon Power Plant] PM [preventive maintenance] program inadequately inspects and cleans torque switch contacts. The close torque switch contacts for Valve 1-LCV-107 were dirty and/or oxidized." PG&E staff had performed a search of industry operating experience in AR A0616766 and found several events where dirty torque switch contacts prevented a Limitorque actuator from functioning. The recommended corrective action in AR A0616766 was to revise Procedure MP E-53.10A, "Preventive Maintenance of Limitorque Motor Operators," Revision 28, to require inspecting the torque switch contact surfaces and cleaning contacts, if needed, during the inspection and lubrication of the actuator. The response to the recommended corrective actions in AR A0616766 stated that the procedure already contained a step to inspect the condition and alignment of torque switch contacts. Subsequently, a step to burnish the contacts of the torque switches was added to Procedure MP E-53.10A.

The inspectors observed an additional case where dirty contacts on a torque limit switch may have prevented Valve FW-2-LCV-109 from closing on March 15, 2003. Valve FW-2-LCV-109 is also a discharge valve for the turbine-driven auxiliary feedwater pump on Unit 2. AR A0578562 stated that operators attempted to close Valve FW-2-LCV-109 during a test of the turbine-driven AFW pump, but the valve failed to close. However, the valve was opened before adequate troubleshooting could be initiated to determine the cause. Therefore, PG&E could not determine the cause of the actuator failure since the valve actuator performed appropriately thereafter. An additional failure of Valve FW-1-LCV-108 occurred in February 2006.

<u>Analysis</u>: No analysis has been performed based on additional inspection is needed to determine whether a performance deficiency exists. The inspection will consider any common cause aspects between the three valves that have experienced failures.

<u>Enforcement</u>: No enforcement action has been identified. URI 50-275/05-05-03, Corrective Actions to Prevent Repetitive Failures of Auxiliary Feedwater Limitorque Valves (Section 1R15).

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the six below listed postmaintenance test activities of risk-significant systems or components. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design basis documents to determine the safety functions; (2) evaluate the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly re-aligned, and deficiencies during testing were documented. The inspectors also reviewed the FSAR Update to determine if PG&E identified and corrected problems related to postmaintenance testing.

- October 11, 2005: Unit 2, Tension hold-down bolts for Centrifugal Charging Pump 2-1
- November 7, 2005: Unit 1, Battery 1-3 modified performance test
- November 23, 2005: Unit 2, Diesel Engine Generator 2-3 lube oil heater contactor failure
- November 27, 2005: Unit 1, Repair of torn structural I-beam
- November 23, 2005: Unit 1, Diesel Engine Generator 1-2 breaker was slow to close
- November 24, 2005: Unit 1, Component Cooling Water Pump 1-2 failed to start on a safety injection signal
- December 19, 2005: Unit 1, Vital Battery Cells 37 and 60 replacement

Documents reviewed by the inspectors are listed in the Attachment.

The inspectors completed seven samples

b. Findings

(1) Vital Battery Cells 37 and 60 Replacement

10 CFR Part 50, Appendix B, Criterion II, “Quality Assurance Program,” requires, in part, that the quality assurance program shall provide for indoctrination and training of personnel performing activities affecting quality as necessary to assure that suitable proficiency is achieved and maintained. Contrary to this, on November 16, 2005, PG&E failed to provide for adequate indoctrination and

training of personnel for Vital Battery 1-2 cell replacement in order to assure that suitable proficiency is achieved and maintained. Specifically, step 5.12.4 of Procedure TQ2.ID4, "Training Program Implementation," Revision 8, required maintenance personnel to document the circumstances for requiring the use of an unqualified worker given that a subject matter expert was providing work oversight. The vital battery system engineer provided oversight of unqualified workers to replace Cells 37 and 60 on Vital Battery 1-2 since qualified staff were unavailable to perform the work. However, maintenance personnel failed to document the circumstances for requiring the use of the unqualified workers to perform the work and the system engineer (subject matter expert) to oversee the work. Using IMC 0612, Appendix B, this issue was determined to be a minor violation of NRC requirements because the failure to provide documentation did not affect the capability of Vital Battery 1-2 to perform its safety function. Furthermore, critical aspects of the cell replacement were adequately performed. The finding has been entered into PG&E's CAP as AR A0655870.

(2) Agastat ETR Time-Delay Relay Failures

Introduction: An unresolved item was identified regarding Agastat ETR time-delay relays and how they caused the slow feeder breaker closure for DEG 1-2 and the failure of CCW 1-2 to start on a safety injection signal. Resolution is pending upon completion of the relay failure analysis performed by PG&E and the vendor.

Description. While performing surveillance test STP M-13G, "4kV Bus G Non-SI Auto-Transfer Test," Revision 28A, on November 21, 2005, PG&E staff noted that DEG 1-2 feeder breaker closed at 23 seconds versus the 17-second acceptance criteria in the test procedure. Engineers and maintenance technicians subsequently performed troubleshooting and determined that Relay 62HG3B was the source of the slow breaker closure. Relay 62HG3B was an Agastat ETR14D time-delay relay. Maintenance technicians bench-tested the relay and found that it exhibited considerable drift from its time-delay setpoint of 17 seconds (as-found was 19.98 seconds). Maintenance technicians replaced the relay, and operators successfully reperformed STP M-13G.

On November 23, 2005, while performing surveillance test STP M-15, "Integrated Test of Engineered Safeguards and Diesel Generators," Revision 38A, CCW Pump 1-2 failed to start on a safety injection signal. Engineers and maintenance technicians performed troubleshooting and found that Relay 2HG12/TD (Agastat ETR14D time-delay relay) failed to actuate. Technicians subsequently replaced the relay, and operators were able to successfully run CCW Pump 1-2 from a safety injection signal.

PG&E staff reviewed industry operating experience on the Agastat ETR14D time-delay relays and found approximately 25 issues in the past 21 years. Most of the issues involved poor solder connections. The inspectors also reviewed operating experience on the Agastat ETR14D time-delay relays but did not find any applicable experience. Most operating experience associated with Agastat time-delay relays has been associated with the electro-pneumatic models. A subsequent search of operating experience with the relays at Diablo Canyon Power Plant showed only four reliability issues, with only one issue in the past year. Currently, PG&E does not consider the two relay failures to be indicative of a larger problem with the Agastat ETR14D time-delay relays based on good performance from the relays in the past and successful testing of the other relays on Unit 1 during Refueling Outage 1R13.

PG&E planned to send the two failed relays to the vendor for failure analysis. The inspectors will review the failure analysis upon its completion.

Analysis: The safety significance of any performance issues identified upon review of PG&E's failure analysis will be determined at that time.

Enforcement: This issue remains unresolved pending NRC review of the relay failure analysis: URI 50-275/05-05-04; Assess Failure of Agastat ETR Time-Delay Relays.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the following risk-significant refueling items or outage activities to verify defense-in-depth commensurate with the outage risk control plan, compliance with the TS, and adherence to commitments in response to Generic Letter 88-17, "Loss of Decay Heat Removal:" (1) the risk control plan; (2) tagging/clearance activities; (3) reactor coolant system instrumentation; (4) electrical power; (5) decay heat removal; (6) spent fuel pool cooling; (7) inventory control; (8) reactivity control; (9) containment closure; (10) reduced inventory or midloop conditions; (11) refueling activities; (12) heatup and cooldown activities; (13) restart activities; and (14) identification and implementation of appropriate corrective actions associated with refueling and outage activities. The inspectors' containment inspections included observations of the containment sump for damage and loose material; and supports, braces, and snubbers for evidence of excessive stress, water hammer, or aging. Documents reviewed by the inspectors included the Unit 1 Refueling Outage 1R13 Outage Safety Plan.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the FSAR Update, procedure requirements, and TS to ensure that the three below listed surveillance activities demonstrated that the SSC's tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumpers; (7) test data; (8) testing frequency and method demonstrated TS operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarm setpoints. The inspectors also verified that PG&E identified and implemented any needed corrective actions associated with the surveillance testing.

- October 7, 2005: Unit 1 - Inservice Test, Procedure STP V-3F1, "Exercising Valve FCV-495, ASW Pump 2 Crosstie Valve," Revision 21

- November 21, 2005: Unit 1, Procedure STP M-13G, "4kV Bus G Non-SI Auto-Transfer Test," Revision 28A

- November 22, 2005: Unit 2, Procedure STP M-15, "Integrated Test of Engineered Safeguards and Diesel Generators," Revision 38A

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert Notification System Testing (71114.02)

a. Inspection Scope

The inspector discussed with PG&E staff the status of offsite siren and tone alert radio systems and PG&E changes to the siren testing methodology to determine the adequacy of PG&E methods for testing the alert and notification system in accordance with 10 CFR Part 50, Appendix E. PG&E's alert and notification system testing program was compared with criteria in NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1; Federal Emergency Management Agency (FEMA) Report REP-10, "Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants"; and PG&E's current FEMA-approved alert and notification system design report.

The inspector completed one sample.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a. Inspection Scope

The inspector reviewed the following documents related to the emergency response organization augmentation system to determine PG&E's ability to staff emergency response facilities in accordance with PG&E's emergency plan and the requirements of 10 CFR Part 50, Appendix E:

- OM10.DC2, "ERO on-call," Revision 4
- OM10.ID4, "ERO Management," Revision 7
- Evaluations for call-in and drive-in drills conducted in 2005

The inspector completed one sample.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspector reviewed the following documents related to PG&E's corrective action program to determine PG&E's ability to identify and correct problems in accordance with 10 CFR 50.47(b)(14) and 10 CFR 50, Appendix E:

- EPG 01, "Problem Identification," May 17, 2002

- Summaries of all corrective actions assigned to the emergency preparedness department during calendar years 2004 and 2005

- Procedure OM7.ID1, "Problem Identification and Resolution - Action Requests," Revision 20A

- Details of 42 selected actions requests

- Five quality assurance audits and assessments

- Three drill and exercise drill reports

The inspector completed one sample.

b. Findings

No findings of significance were identified.

1EP6 Emergency Preparedness Evaluation (71114.06)

a. Inspection Scope

For the one below simulator-based training evolution contributing to Drill/Exercise Performance and Emergency Response Organization Performance Indicators, the inspectors: (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and Protective Action Recommendation development activities; (2) compared the identified weaknesses and deficiencies against PG&E identified findings to determine whether PG&E is properly identifying failures; and (3) determined whether PG&E performance is in accordance with the guidance of the NEI 99-02, "Voluntary Submission of Performance Indicator Data," acceptance criteria.

- November 10, 2005: Unit 1, Shift Manager classification and declaration of separate events involving main turbine damage, high effluent discharge, anticipated transient without scram, steam generator tube rupture, fuel assembly damage, and a tsunami

Documents reviewed by the inspectors included:

- Procedure EP G-3, "Emergency Notification of Off-Site Agencies," Revision 44
- Diablo Canyon Power Plant Emergency Plan, Revision 4

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety [OS]

2OS1 Access Control To Radiologically Significant Areas (71121.01)

a. Inspection Scope

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

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

- Controls (surveys, posting, and barricades) of three radiation, high radiation, or airborne radioactivity areas

- Radiation work permits, procedures, engineering controls, and air sampler locations

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

- Adequacy of PG&E's internal dose assessment for any actual internal exposure greater than 50 millirem committed effective dose equivalent

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

- Self-assessments, audits, licensee event reports, and special reports related to the access control program since the last inspection

- Corrective action documents related to access controls

- PG&E actions in cases of repetitive deficiencies or significant individual deficiencies

- Radiation work permit briefings and worker instructions

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

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

- Changes in PG&E procedural controls of high dose rate - high radiation areas and very high radiation areas

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

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

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

Either because the conditions did not exist or an event had not occurred, no opportunities were available to review the following items:

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

The inspector completed 21 of the required 21 samples.

b. Findings

Introduction: The inspector identified a NCV of 10 CFR 20.1902 because PG&E failed to post a radiation area. The violation had very low safety significance.

Description: On November 15, 2005, the inspector toured the 115-foot yard area. Inside Vault 26, the inspector identified, through independent measurements, an area in which the radiation dose rates were approximately 30 millirem per hour at 30 centimeters from the surfaces of radioactive material containers. The dose rate was confirmed by a radiation protection technician using an ion chamber radiation detection device. The inspector observed that neither the discrete area nor the open entrance to Vault 26 was posted with a radiation area warning sign, although the auxiliary building doorway to the yard was posted as a radiation area.

The inspector reviewed the applicable guidance in NUREG/CR-5569, Revision 1, Health Physics Positions 036, “Posting of Entrances to a Large Room or Building as a Radiation Area,” and 066, “Guidance for Posting Radiation Areas.” Because the yard area was large and very little of it was a radiation area, the inspector concluded that posting on the doorway to the yard rather than the discrete areas was not sufficient to inform radiation workers of radiological hazards in their work areas.

Analysis: The failure to post a radiation area is a performance deficiency. The finding was more than minor because it was associated with one of the cornerstone attributes (exposure control and monitoring) and the finding affected the Occupational Radiation Safety cornerstone objective, in that, uninformed workers could unknowingly accrue additional radiation dose. Because the finding involved the potential for unplanned, unintended dose resulting from conditions that were contrary to NRC regulations, the finding was evaluated using the Occupational Radiation Safety Significance Determination Process. The inspector determined that the finding had no more than very low safety significance because: (1) it did not involve American Society of Mechanical Engineers (ALARA) planning and controls, (2) there was no personnel overexposure, (3) there was no substantial potential for personnel overexposure, and (4) the finding did not compromise PG&E’s ability to assess dose. The finding also has cross-cutting aspects related to problem identification and resolution, in that, a similar violation was previously identified during Inspection 05000275/2002004; 0500323/2002004.

Enforcement: 10 CFR 20. 003 defines a radiation area as an area, accessible to individuals, in which radiation levels could result in an individual receiving a dose equivalent in excess of 5 millirem in an hour at 30 centimeters from the radiation source or from any surface that the radiation penetrates. 10 CFR 20. 902 requires each radiation area be posted with a conspicuous sign or signs. PG&E violated this requirement when it did not post the discrete area or the open entrance to Vault 26.

This violation is in PG&E's CAP as AR A0652226. Because this finding is of very low safety significance and it was entered into PG&E's corrective action program, it is being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000275; 323/2005-05-05, Failure to Post a Radiation Area.

## 4. OTHER ACTIVITIES

### 4OA1 Performance Indicator(PI) Verification (71151)

#### .1 Emergency Preparedness Cornerstone

##### a. Inspection Scope

The inspector sampled PG&E submittals for the PIs listed below for the period of October 1, 2004, through September 30, 2005. The definitions and guidance of Nuclear Engineering Institute 99-02, "Regulatory Assessment Indicator Guideline," Revisions 2 and 3, were used to verify PG&E's basis for reporting each data element in order to verify the accuracy of PI data reported during the assessment period. PG&E PI data were also reviewed against the requirements of Procedure AWP EP-001, "Emergency Preparedness Performance Indicators," Revision 5.

- Drill and Exercise Performance
- Emergency Response Organization Participation
- Alert and Notification System Reliability

The inspector reviewed a 100 percent sample of drill and exercise scenarios and licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. The inspector reviewed selected emergency responder qualification, training, and drill participation records. The inspector reviewed the evaluation of the June 14, 2005, Tsunami event. The inspector reviewed alert and notification system testing procedures and a 100 percent sample of siren test records. The inspector also interviewed PG&E personnel responsible for collecting and evaluating PI data.

The inspector completed three samples.

##### b. Findings

Introduction: A Severity Level IV NCV of 10 CFR 50.9 was identified because PG&E failed to provide complete and accurate PI information to the NRC. Specifically, the inspector identified two errors in the second quarter 2005 drill and exercise performance PI opportunities evaluated by PG&E and, when the PI was recalculated, the drill and exercise performance PI crossed the Green-to-White performance band threshold for the second quarter of 2005.

Description: During review of the second quarter 2005 drill and exercise performance PI documentation, the inspector identified two emergency notification forms that were incorrectly annotated as "emergency" vice "drill." Neither of these errors had been evaluated as a missed opportunity for the drill and exercise performance PI, and both had been reported as successful opportunities. Both of these drill and exercise performance opportunities were from the 2005 annual licensed operator requalification operating tests in the plant control room simulator. When the drill and exercise performance PI data for second quarter 2005 was re-evaluated with these two corrections, the indicator crossed the Green-to-White threshold. PG&E subsequently identified a third example of the same error.

The operating tests had been identified for evaluation of emergency preparedness PIs, and operations department learning services training personnel conducted the evaluations. Documentation of the evaluations was then provided to the Emergency Preparedness Department staff, who then reviewed the evaluations and summarized the quarterly results for reporting of the PIs. For the entire second quarter, 33 drill and exercise performance opportunities were identified, and 25 were originally evaluated and reported as successful. Following the inspector's identification of two inaccurate notification forms, PG&E performed a review and identified an additional inaccurate notification form with the same error as identified by the inspector. As an immediate corrective action to the errors noted in the second quarter evaluations, PG&E also conducted a review of the third quarter PI data, which had been prepared for submission, to verify the accuracy of the evaluation of the 162 opportunities that had been performed in the third quarter. One additional error was identified on a notification form where an error had been identified and corrected with the time of the declaration; however, the method of correction did not meet accuracy standards of the facility and; therefore, the notification opportunity was reevaluated as a missed opportunity.

Historically, the drill and exercise performance PI at Diablo Canyon Power Plant was approximately 95 percent. After the second quarter 2005 performance was added to the PI, the indicator dropped to 90.8 percent (before correction). PG&E took corrective action in the third quarter by conducting refresher training and job performance measure evaluations with all shift manager qualified senior licensed operators. This resulted in 162 PI opportunities for the third quarter.

The inspector reviewed the performance deficiencies associated with the missed drill and exercise performance PI opportunities. During the second quarter evaluations, two classification opportunities were missed because of late classifications of a site area emergency, and the remaining nine missed opportunities were accuracy errors on the emergency notification form. During the third quarter evaluations, six missed classifications were identified, and 12 inaccurate notification forms were identified. The inspector observed that over 80 percent of the missed opportunities during the second quarter 2005 were due to inaccurate emergency notification forms and that over 65 percent of the missed opportunities during the third quarter were because of inaccurate emergency notification forms with the same errors being made in both quarters. The inspector noted that the refresher training conducted prior to the job performance measures as a corrective action for the second quarter performance deficiencies was only partially successful but did not correct the error rate to historical facility standards. The inspector concluded that attention to detail errors being made on the notification forms by the senior licensed operators had increased significantly as compared to pre-2005 historical performance.

PG&E submitted corrected second quarter PI data on October 21, 2005, as well as the third quarter PI data. Both quarters indicated the drill and exercise PI as in the White performance band.

Analysis: The failure to accurately report the drill and exercise performance PI data for the second calendar quarter of 2005 was a performance deficiency that was more than minor because it was associated with a cornerstone attribute and affected the emergency preparedness cornerstone objective (to ensure the adequate protection of the public health and safety). The finding had human performance cross-cutting aspects that involved the failure to accurately assess and report the results of evaluated emergency drills, which, if accurately calculated and reported, would have caused the NRC to perform an additional inspection in 2005. This issue was not suited for significance determination process analysis and was evaluated in accordance with NRC's Enforcement Policy. Supplement 7, Section D.3, to the NRC Enforcement Policy describes this finding as a Severity Level IV violation.

Enforcement: 10 CFR 50.9 requires, in part, that "information provided to the Commission . . . by a licensee . . . shall be complete and accurate in all material respects." Contrary to this, PG&E failed to report complete and accurate information for the second calendar quarter of 2005 and that the drill and exercise performance PI had crossed the threshold from the Green into the White performance band. The NRC considers errors in PI data reporting that cause a PI to cross the Green-to-White threshold to be more than minor because such errors have the potential for impacting the NRC's ability to perform its regulatory function, which was in this case to perform a supplemental inspection. This Severity Level IV violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000275; 323/05-05-06, Failure to Accurately Assess and Report Performance Indicator Data). This violation is in PG&E's CAP as ARs A0648578 and A0648581 and Nonconformance Reports N0002199 and N0002200. PG&E's corrective actions included correction of the second quarter 2005 drill and exercise PI data and initiation of a root cause analysis.

.2 Occupational and Public Radiation Safety Cornerstone

a. Inspection Scope

Occupational Radiation Safety Cornerstone

- Occupational Exposure Control Effectiveness

The inspector reviewed PG&E's documents from October 2004 through September 2005. The review included corrective action documentation that identified occurrences in locked high radiation areas (as defined in PG&E's technical specifications), very high radiation areas (as defined in 10 CFR 20. 003), and unplanned personnel exposures (as defined in NEI 99-02). Additional records reviewed included ALARA records and whole body counts of selected individual exposures. The inspector interviewed PG&E personnel that were accountable for collecting and evaluating the PI data. In addition, the inspector toured plant areas to verify that high radiation, locked high radiation, and very high radiation areas were properly controlled. PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 3, were used to verify the basis in reporting for each data element.

Public Radiation Safety Cornerstone

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

The inspector reviewed PG&E documents from October 2004 through September 2005. PG&E records reviewed included corrective action documentation that identified occurrences for liquid or gaseous effluent releases that exceeded PI thresholds and those reported to the NRC. The inspector interviewed PG&E personnel that were accountable for collecting and evaluating the PI data. PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 3, were used to verify the basis in reporting for each data element.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a daily screening of items entered into PG&E's CAP. This assessment was accomplished by reviewing ARs and event trend reports, and attending daily operational meetings. The inspectors: (1) verified that equipment, human performance, and program issues were being identified by PG&E at an appropriate threshold and that the issues were entered into the CAP; (2) verified that corrective actions were commensurate with the significance of the issue; and (3) identified conditions that might warrant additional followup through other baseline inspection procedures.

b. Findings

No findings of significance were identified.

.2 Selected Issue Follow-up Inspection

a. Inspection Scope

In addition to the routine review, the inspectors selected the one below listed issue for a more in-depth review. The inspectors considered the following during the review of PG&E's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause, and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of corrective actions; and (7) completion of corrective actions in a timely manner.

- November 29, 2005: Unit 1, ECCS check valve back-leakage

Documents reviewed by the inspectors are listed in the Attachment.

b. Findings

Introduction: The inspectors identified a Green, NCV of 10 CFR Part 50, Criterion XVI, for the failure to promptly evaluate ECCS check valve back-leakage and identify appropriate corrective actions to prevent recurrence. Since 2000, Units 1 and 2 have experienced ECCS check valve back-leakage which provided a pathway for reactor coolant to enter the safety injection discharge header and accumulators, or the outflow of accumulator liquid into the safety injection discharge header. Industry experience has shown that ECCS check valve back-leakage has the potential to cause gas accumulation in ECCS piping that can lead to gas-binding of ECCS pumps and/or water hammer of ECCS piping.

Description: The ECCS is designed with at least two check valves in series to isolate the high pressure reactor coolant system (RCS) from lower pressure ECCS components. The check valves that are in series from the four loops of the RCS to the safety injection system are Valves SI-1-8948A/B/C/D (first-off check valves) and Valves SI-1-8819A/B/C/D (second-off check valves). Valves 8948A-D were 10-inch, Darling swing check valves, and Valves 8819A-D are 2-inch Rockwell, Y-pattern, piston check valves.

Beginning in November 1999, PG&E began to observe pressurization of the safety injection system discharge header on Unit 2. At that time, PG&E staff believed the pressurization was a result of back-leakage of the first- and second-off check valves for the safety injection system, although leakage tests of the valves in the previous outage showed no leakage. Beginning in August 2000, PG&E staff noted that the Unit 1 safety injection discharge header also began to pressurize. PG&E staff surmised that the pressurization was the result of back-leakage of the first- and second-off check valves from the RCS. For both Units 1 and 2, the safety injection discharge header would pressurize above the accumulator pressure of approximately 650 psig, which would conclude that back-leakage through the 8948 and 8819 valves was occurring. On occasions, operators would have to relieve pressure in the safety injection discharge header to prevent any challenges to the safety injection discharge header relief valve, which was set at 1750 psig.

The inspectors reviewed industry operating experience associated with ECCS check valve back-leakage. In particular, NRC Information Notice 97-40, "Potential Nitrogen Accumulation Resulting from Backleakage From Safety Injection Tanks," discussed nitrogen gas that had come out of solution in low-pressure safety injection systems and caused water hammers at two plants. The nitrogen gas came from water in the safety injection tanks that had arrived at the discharge headers of the safety injection systems due to back-leakage of ECCS check valves. In dealing with the safety injection discharge header pressurization, PG&E acknowledged in AR A0496806 that there was industry operation experience regarding ECCS check valve back-leakage and the potential for gas-binding of pumps and/or water hammer. However, no voiding of ECCS piping or pumps were found in Units 1 or 2 safety injection discharge headers. PG&E had also evaluated other industry operating experience in AR A0636984, and it also covered situations where nitrogen gas could cause voiding in ECCS piping and pumps if nitrogen-saturated water was allowed into lower pressure piping due to back-leakage of ECCS check valves. The inspectors observed that there was no current ECCS check valve back-leakage into the RHR system discharge header for either unit.

Although some maintenance was performed on the ECCS check valves since 2000, pressurization of the safety injection discharge header was experienced each operating cycle, on both units, since the first occurrence in 1999/2000. Specifically, Valves 8948A-D received pressure isolation valve leak testing each refueling outage, as well as diagnostic testing once every $4^{th}$ outage. The inspectors found that Valves 8819A-D have not received diagnostic or any internal inspection since their initial installment before plant operation. Valves 8819A-D receive pressure isolation valve leak testing each refueling outage. The inspectors noted that PG&E tested the first- and second-off ECCS check valves following each outage and the majority of the valves exhibited zero recorded leakage. On November 29, 2005, at the exit of Refueling Outage 1R13, PG&E noted in AR A0610421 that the Unit 1 safety injection discharge header was pressurizing to over 1000 psig. The inspectors observed in the subsequent days that operators, at times, were venting the safety injection discharge header twice a shift in order to prevent the pressurization from challenging the safety injection discharge header relief valve. The inspectors also observed that PG&E staff was monitoring for voids in the safety injection discharge header piping and no voids were found. PG&E staff was developing plans to try and seat the first- and/or second-off check valves between the RCS and the safety injection discharge header in order to prevent pressurization. PG&E staff was also developing long-term corrective actions to prevent future safety injection discharge header pressurization.

The inspectors determined that PG&E staff failed to adequately evaluate and develop corrective actions for implementation to correct the ECCS check valve back-leakage that continued to pressurize the safety injection discharge headers on both Units 1 and 2. Specifically, the inspectors noted that, in the past, ECCS check valves would only receive maintenance if their leakage provided a significant burden to operations. The inspectors also noted that maintenance on ECCS check valves in the past had addressed ECCS check valve back-leakage issues. Although the majority of ECCS check valves exhibited zero leakage at the end of refueling outages, both Units 1 and 2 have continued to experience ECCS check valve back-leakage since 2000. In assessing the corrective actions for ECCS check valves, the inspectors have not identified were PG&E has evaluated the adequacy of maintenance and testing to determine the corrective actions needed to address the long-standing issue of ECCS check valve back-leakage.

Analysis: The performance deficiency associated with this finding involved the failure to promptly evaluate ECCS check valve back-leakage and identify appropriate corrective actions to prevent recurrence as required by 10 CFR Part 50, Criterion XVI. The finding is greater than minor because it is associated with the Mitigating Systems Cornerstone attribute of equipment performance and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using IMC 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it did not represent an actual loss of safety function, represent an actual loss of safety function for a single train for greater than the TS allowed outage time, or screen as potentially risk significant due to seismic, fire, flooding, or severe weather initiating events. The cause of the finding is related to the crosscutting element of problem identification and resolution in that PG&E did not adequately evaluate and implement timely corrective actions to ECCS check valve back-leakage.

Enforcement: 10 CFR Part 50, Criterion XVI, "Corrective Actions," requires, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to this, ECCS check valve back-leakage has existed on both units since 2000, and PG&E has failed to promptly evaluate and implement corrective actions for the back-leakage. The ECCS check valve back-leakage added operator burden and increased the potential for gas voiding of ECCS components. At this time, PG&E has not been able to accurately determine which valves have back-leakage and what has caused the leakage. Corrective actions to restore compliance included verification of ECCS operability, troubleshooting, and evaluation of possible future actions to prevent ECCS check valve back-leakage. Because this finding is of very low safety significance and has been entered into PG&E's CAP as ARs A0526037 and A0610421, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275; 323/05-05-07, Failure to Promptly Evaluate Emergency Core Cooling System Check Valve Back-leakage and Identify Appropriate Corrective Actions to Prevent Recurrence.

.3 Semiannual Trend Review

b. Inspection Scope

The inspectors completed a semi-annual trend review of repetitive or closely-related issues that were documented in action requests, system and component health reports, quality assurance audits, trend reports, Diablo Canyon Power Plant internal PIs, and NRC inspection reports to identify trends that might indicate the existence of more safety-significant issues. The inspectors review consisted of the 6-month period of July 1 to December 31, 2005. When warranted, some of the samples expanded beyond those dates to fully assess the issue. The inspectors also reviewed corrective action program items associated with turbine building high-energy line break (HELB) louvers and safety-related check valves. The inspectors compared and contrasted their results with the results contained in PG&E's quarterly trend reports. Corrective actions associated with a sample of the issues identified in PG&E's trend report were reviewed for adequacy. Documents reviewed by the inspectors are listed in the attachment.

b. Findings

The inspectors reviewed two equipment reliability trends as part of the semiannual trending of problem identification and resolution. Specifically, the inspectors reviewed documents and observed the condition of safety-related check valves and turbine building HELB louvers. With respect to the turbine building HELB louvers, the inspectors noticed that the louvers were installed in 1996. In 1998, PG&E staff began to find the louvers hard to open due to corrosion at the vanes and bearings. At this time, a preventive maintenance program was developed to ensure the mobility of the louver vanes. The louvers were required to be able to freely open to relieve pressure from a main steam line break inside the turbine building in order to prevent potential structural damage to the building. PG&E staff later determined that the louvers were sticking in the closed position because of galvanic corrosion. The louver vanes and frame were constructed of aluminum, and the vane bearings were constructed of copper. The two dissimilar metals, along with moisture from the marine environment, provided for the galvanic corrosion.

In 2002, PG&E staff issued a design change to permanently fix the louvers in the open position for functionality during an HELB. However, during the rainy season, rain would blow into the turbine building through the open louvers and as much as 100 gallons of water may accumulate in the turbine building and potentially impact plant equipment such as the Unit 2 hydrogen seal oil skid. Subsequently, PG&E instituted a temporary modification in 2003 and 2004 to return some of the louvers on the Unit 2 side of the turbine building to their original capability to freely open and close, in order to mitigate the rainwater intrusion into the building. The temporary modification required monthly surveillance of the louvers to ensure that they would open freely. At the end of the rainy season the louvers would again be fixed in the open position. In 2005, a design change replaced the temporary modification but executed the same actions; namely unfixing a portion of the Unit 2 louvers during the rainy season, instituting the monthly surveillance of the louvers, and returning them to their fixed open position after the rainy season. In 2001, PG&E developed Long-Term Plan 2001-S080-015 to address the long-term issue regarding the louvers and rainwater intrusion. As of December 31, 2005, funding and work for Long-Term Plan 2001-S080-015 is scheduled for 2008.

The inspectors also reviewed the problem identification and resolution aspects associated with check valve reliability and maintenance at Diablo Canyon Power Plant. In AR A0637470, PG&E and other outside industry reviewers noted several areas in the plant where long-standing check valve reliability issues posed operator burden and/or reduced safety system operational margin. Examples of such issues include:

- Auxiliary feedwater discharge check valve back-leakage (AR A0612683)
- Unit 2 reactor coolant pump seal leak-off return line failed its local leak rate test 7 times in the last 10 outages (AR A0540712)
- Centrifugal charging pump recirculation check valve back-leakage (ARs A0586882, A0597376, and A0615708)
- Diesel engine generator lube oil check valve back-leakage that could introduce lube oil into the cylinders (ARs A0601386 and A0601388)

The apparent causes of these long-standing check valve issues were the result of a check valve preventive maintenance program that needed optimization, roles and responsibilities regarding the check valve program were not clearly defined or understood, and trending mechanisms and metrics were inconsistent and not reflective of the check valve problems. PG&E had initiated corrective actions to address each of these causes.

The inspectors noted that ECCS check valves were another set of check valves that have historically added operator burden and had the potential to impact safety system performance. Specifically, the pressure isolation check valves between the reactor coolant system, the accumulators, and the safety injection system have experienced back-leakage on both Units 1 and 2 since 1999. A finding associated with the back-leakage of ECCS check valves is discussed in Section 4OA2.2.

.4 Inservice Inspection

a. Inspection Scope

Section 02.05 of Inspection Procedure 71111.08 requires review of a sample of problems associated with inservice inspections documented by the licensee in the CAP for appropriateness of the corrective actions.

The inspectors reviewed nine action requests which dealt with inservice inspection activities and found that the corrective actions were appropriate. From this review the inspectors concluded that PG&E had an appropriate threshold for entering issues into the CAP and has procedures that direct a root cause evaluation when necessary. PG&E also had an effective program for applying industry operating experience.

b. Findings

No findings of significance were identified.

.5 Emergency Preparedness Annual Sample Review

a. Inspection Scope

The inspector selected 42 action requests for detailed review. The reports were reviewed to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspector evaluated the condition reports against the requirements of Procedure OM7.ID1, “Problem Identification and Resolution - Action Requests,” Revision 20A; and Emergency Planning Guide EPG 01, “Problem Identification,” Revision May 17, 2002.

b. Findings

No findings of significance were identified.

.6 Radiation Protection

a. Inspection Scope

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

b. Findings

Section 2OS1 describes an NRC identified finding, which involved the failure to post a radiation area. The finding was the same as described in NCV 50-275/02-04-02.

.7 PI&R Crosscutting Aspects

Section 1R14 identified a problem identification and resolution crosscutting aspect for the failure to conduct a circuit isolation plan, which was the repeat of a similar performance deficiency described in NRC Inspection Report 05000275; 323/2005004.

Section 2OS1 identified a problem identification and resolution crosscutting aspect for the failure of radiation protection personnel to post a radiation area and the violation was similar to a violation previously identified in NRC Inspection Report 050000275; 323/2002004.

Section 4OA2.2 identified a problem identification and resolution crosscutting aspect for the failure of PG&E to adequately evaluate and implement timely corrective actions to ECCS check valve back-leakage.

4OA3 Event Follow-up (71153)

.1 (Closed) Licensee Event Report 05000323/2005001-00, TS 3.4.10 Not Met During Pressurizer Safety Valve Surveillance Testing Due to Random Lift Spread

On January 27, 2005, during scheduled testing of Unit 2 pressurizer safety valves, PG&E identified two of three pressurizer safety valves outside the TS 3.4.10 lift setting of $\geq$2460 and $\leq$2510 psig.

In NRC Inspection Report 05000275; 323/2005003, an NRC-identified, Green NCV of 10 CFR Part 50, Criterion XVI, was identified for this issue. PG&E documented the problem in Nonconformance Report N0002197. No new information that would change the disposition of this issue was provided in this LER. This LER is closed.

4OA5 Other

.1 TI 2515/160 - Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors

a. Inspection Scope

The inspectors reviewed PG&E's actions regarding the inspection and repair associated with Alloy 82/182/600 material that may have been used in pressurizer penetration nozzles, steam space piping connections, heads, and shells. Specifically, the inspectors reviewed PG&E's response to NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized Water Reactors." PG&E documented in their response to the bulletin that no Alloy 82/182/600 material was used in the construction or welds of the Unit 1 pressurizer. PG&E did not commit to, or perform, any nondestruction examination methods for the Unit 1 pressurizer. PG&E did perform a boric acid walkdown of the pressurizer, and the inspectors performed an independent boric acid inspection of pressurizer.

The activities required in TI 2515/160 for Diablo Canyon Power Plant Unit 1 have been completed. This temporary instruction is closed for Unit 1.

b. Findings

No findings of significance were identified.

.2 TI 2515/150 - Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009)

a. Inspection Scope

This area was inspected to verify that PG&E's reactor pressure vessel head and vessel head penetration nozzle inspection activities are implemented in accordance with the requirements of First Revised NRC Order EA-03-009 (NRC Accession No. ML040220391) issued on February 20, 2004, and the Relaxation of Requirements regarding alternate examination coverage for reactor pressure vessel head penetration nozzles authorized by NRC letter dated October 26, 2005.

The inspectors observed and reviewed PG&E's activities associated with the volumetric (ultrasonic) examinations of the reactor pressure vessel head and vessel head penetration nozzles.

The temporary instruction requires the inspectors to provide a qualitative description of the effectiveness of PG&E's examinations which, at a minimum, would consist of a response to the following questions with a brief description of inspection scope and results.

(1) For each of the examination methods used during the outage, was the examination:

(a) Performed by qualified and knowledgeable personnel?

For the inspector-observed ultrasonic examinations performed on the penetration nozzles identified in the Table in Section 1R08, paragraph 02.01.a, above, the inspectors verified the nondestructive examination certifications of the four personnel who performed those examinations. Discussions with those examiners during the course of the examinations allowed the inspectors to determine that the examiners were well qualified and knowledgeable in that examination method.

(b) Performed in accordance with demonstrated procedures?

The inspectors verified that the examinations were performed in accordance with the site-specific demonstrated and qualified procedures and the applicable ASME Code requirements

(c) Able to identify, disposition, and resolve deficiencies?

The inspectors observed that indications identified during the ultrasonic examinations were dispositioned in accordance with the acceptance criteria identified in the ASME Code qualified nondestructive examination procedure used to perform the examinations.

(d) Capable of identifying the primary water stress-corrosion cracking and/or reactor pressure vessel head corrosion phenomena described in the Order?

The nondestructive examination personnel and the procedure used to perform the ultrasonic examinations were qualified (through demonstration) to detect primary water stress-corrosion cracking and reactor pressure vessel head corrosion indications.

(2) What was the physical condition of the reactor vessel head (e.g., loose material, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

The inspectors were able to view, via remote camera, the physical condition of the reactor vessel head and concluded that there were no viewing obstructions that could adversely impact performance of the volumetric examination.

(3) Could small boron deposits, as described in the Bulletin 01-01, be identified and characterized?

The inspectors did not review the bare metal examination of the reactor vessel head because that part of Temporary Instruction 2515/150 was performed earlier.

(4) What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

At the time of this inspection, no material deficiencies had been identified that required repair.

(5) What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

PG&E submitted, by letter to the NRC dated May 27, 2005, a request for relaxation of examination coverage requirements because of vessel head penetration nozzle end geometry. Specifically, the bottom end of these nozzles are externally threaded, or internally tapered, or both. This nozzle end geometry makes inspection difficult and would involve increased personnel radiation dose. PG&E proposed an alternative inspection that was found to be acceptable and authorized by NRC letter dated October 26, 2005.

The inspectors noted during the observed examinations that actual examination coverage was greater than initially expected.

(6) What was the basis for the temperatures used in the susceptibility ranking calculation, were they plant-specific measurements, generic calculations (e.g., thermal hydraulic modeling, instrument uncertainties), etc.?

Information pertaining to the susceptibility calculation is contained in NRC Inspection Report 50-275;323/04-03.

(7) Was the disposition of indications consistent with the guidance provided in Appendix B of this Temporary Instruction during nonvisual examinations? If not, was a more restrictive flaw evaluation guidance used?

At the time of this inspection, no material deficiencies had been identified that required repair.

(8) Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the reactor pressure vessel head?

The inspectors did not review the examination of pressure-retaining components above the reactor pressure vessel head.

(9) Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the reactor pressure vessel head?

The inspectors did not review the examination of pressure-retaining components above the reactor vessel head.

This completes the inspection activities required in Temporary Instruction 2515/150, Revision 3, and this Temporary Instruction is closed with respect to Diablo Canyon Power Plant Unit 1 (50-275).

b. Findings

No findings of significance were identified.

40A6 Management Meetings

Exit Meeting Summary

On October 20, 2005, the inspectors presented the results of the emergency preparedness inspection results to Mr. J. Purkis, Acting Station Director, and other members of his staff who acknowledged the findings.

On November 11, 2005, the inspectors presented the results of the in-service inspection to Mr. D. Taggart, Manager of Quality Verification Department, and other members of PG&E staff. PG&E acknowledged the inspection findings.

On November 17, 2005, the inspectors presented the access controls inspection results to Mr. P. Roller, Director, Operations Services, and other members of his staff who acknowledged the findings.

The resident inspection results were presented on January 12, 2006, to Mr. David Oatley, Vice President and General Manager, Diablo Canyon Power Plant 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.

## 4OA7 Licensee-Identified Violations

The following violations 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, Criterion XVI, "Corrective Actions," requires, in part, that measures be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this, on November 3, 2005, PG&E staff discovered deformation and web tearing at the end connection of the I-beam for Pipe Support 1029-9R. The root cause of the degradation was determined by PG&E to be friction loads with thermal movement of the piping exceeding the shear resistance of the I-beam end connection as it was designed. However, in AR A0653829, PG&E identified the structural maintenance rule walkdowns in 1997 and 2003 as missed opportunities for identifying the degraded I-beam; even though the degradation was determined to have existed at that time. Other missed opportunities included the post-earthquake walkdowns following the Deer Canyon Earthquake on October 18, 2003, the San Simeon Earthquake on December 23, 2003, and the Parkfield Earthquake on September 28, 2004. This finding was determined to be of very low safety significance since Main Steam Lead 4 was determined to be able to retain its structural integrity as a result of any design basis accident. Specifically, structural analysis without the I-beam demonstrated little loss of design margin.

- A self-revealing noncited violation of TS 5.4.1.a. was identified for the failure to appropriately implement the procedure for spent fuel pool skimmer filter replacement. On November 6, 2005, operators restored to service the spent fuel pool skimmer system using Section 6.3.2 of Procedure OP B-7:III, "Spent Fuel Pool System - Shutdown and Clearing and Filter Replacement," Revision 16. After completion of the procedure the spent fuel pool level was noted by watchstanders to be lower than previous readings. PG&E staff later identified Valve SFS-2-8765 was not fully shut. This finding impacted the Initiating Events Cornerstone and was considered more than minor using Example 5.a of IMC 0612. Specifically, Valve SFS-2-8765 was not operated correctly due to the reach rod operator interfering with the valve body before the valve was fully shut. Additionally, operators had two opportunities to identify the mispositioning of Valve SFS-2-8765 but failed to identify the condition. The mis-positioned valve resulted in a loss of approximately 2600 gallons of water from the spent fuel pool. The loss of inventory did not cause level to exceed the TS minimum limits. Therefore, this finding was determined to be of very low safety significance.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

### KEY POINTS OF CONTACT

PG&E personnel

J. Becker, Vice President - Diablo Canyon Operations and Station Director
S. Chesnut, Director, Engineering Services
S. David, Manager, Operations
J. Fledderman, Director, Site Services
R. Hite, Manager, Radiation Protection
D. Jacobs, Vice President - Nuclear Services
S. Ketelsen, Acting Director, Nuclear Quality, Analysis, and Licensing
M. Lemke, Manager, Emergency Preparedness
D. Oatley, Acting Chief Nuclear Officer
J. Purkis, Director, Maintenance Services
P. Roller, Director, Operations Services
D. Taggart, Manager, Quality Verification

### LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 05000275/2005-05-04 | URI | Assess Failure of Agastat ETR Time-Delay Relays |
| 05000275/2005-05-03 | URI | Corrective Actions to Prevent Repetitive Failures of Auxiliary Feedwater Limitorque Valves (Section 1R15) |

Opened and Closed

| | | |
|---|---|---|
| 05000275/2005-05-01 | NCV | Failure to Adequately Assess and Manage Risk Associated With Startup Transformer 1-1 Maintenance (Section 1R14) |
| 05000275/2005-05-02 | NCV | Failure to Properly Implement Procedure for Safety Injection System Operation (Section 1R14) |
| 050000275; 323/2005-05-05 | NCV | Failure to Post a Radiation Area (Section 2OS1) |
| 050000275; 323/2005-05-06 | NCV | Failure to Accurately Assess and Report Performance Indicator Data (Section 4OA1) |
| 050000275; 323/2005-05-07 | NCV | Failure to Promptly Correct Emergency Core Cooling System Check Valve Back-Leakage (Section 4OA2.2) |

Closed

| | | |
|---|---|---|
| 05000323/2005001-00 | LER | Technical Specification 3.4.10 Not Met During Pressurizer Safety Valve Surveillance Testing Due to Random Lift Spread |

LIST OF DOCUMENTS REVIEWED

**Section 1R05: Fire Protection**

Documents
AR PK10-10, “Fire Detected,” Revision 13
OP -2C, “Fire Protection Computer Operation and Response Procedure,” Revision 17 and 18
CP —6, “Fire,” Revision 28
H-5, “Containment and Ventilation Systems,” Revision 14

Drawings
225054, “RCP 1-1 Fire Protection Header,” Revision 1
225055, “RCP 1-2 Fire Protection Header,” Revision 2
225056, “RCP 1-3 Fire Protection Header,” Revision 1
225057, “RCP 1-4 Fire Protection Header,” Revision 1
504472, “Area F Oil Drip Pan Locations,” Revision 6
504473, “Area G Oil Drip Pan Locations,” Revision 7

Action Requests
A0504285 A0647847

**Section 1R06: Flood Protection (71111.06)**

Action Requests

| | | | | | |
|---|---|---|---|---|---|
| A0503193 | A0503272 | A0503276 | A0505617 | A0514634 | A0563252 |
| A0563325 | A0594436 | A0595233 | A0597321 | A0628776 | A0628908 |
| A0635208 | A0635209 | A0639615 | A0638953 | A0646852 | |

Other Documents

Quality Evaluation Q0012233, “Turbine Building Louvers Issues”

Long Term Plan 2001-S080-015, “Redesign and Replace Turbine Building HELB Louvers, Units 1 and 2"

**Section 1R08: Inservice Inspection Activities (71111.08)**

Procedures

| Number | Title | Revision |
|---|---|---|
| ER1.ID2 | Boric Acid Corrosion Control Program | 1 |
| ISI ADD SUCCESS | Inservice Inspection Procedure, *Additional and Successive Inspections* | 1 |
| NDE ET-7 | Eddy Current Examination of Steam Generator Tubing | 7 |
| NDE PT-1 | Solvent Removable Visible Dye Liquid Penetrant Examination Procedure | 1 |
| NDE RT-1 | ASME Code Radiography Procedure | 8 |
| STP M-SGT1 | Steam Generator Tube Inspection | 11 |
| TQ1.ID12 | Qualification and Certification of NDE Personnel | 2 |
| WDI-ET-003 | Intraspect Eddy Current Imaging Procedure for Inspection of Reactor Vessel Head Penetrations | 8 |
| WDI-UT-010 | Intraspect Ultrasonic Procedure for Inspection of Reactor Vessel Head Penetrations, Time of Flight Ultrasonic, Longitudinal Wave and Shear Wave | 11, with FCN01 |
| WDP-9.2 | Qualification and Certification of Personnel in Nondestructive Examination” | 6 |
| WPS 51 | Welding of P8 Materials With GTAW and/or SMAW, ASME III, Reg. Guide 1.44(b) | 8 |

Examination Technique Specification Sheets (ETSS)

| Diablo Canyon Power Plant ETSS | Qualifying EPRI ETSSs |
|---|---|
| ETSS #1 (Bobbin) | 96001.1, 96004.1, 96005.2, 96007.1, 96008.1, 96012.1, 24013.1, and SG-SGDA-02-41 |
| ETSS #2 (Three Coil Plus Point, except U-bend) | 20510.1, 20511.1, 21409.1, 21410.1, 96703.1, 22401.1, and 22842.3 |

| | |
|---|---|
| ETSS #3 (Three Coil Plus Point, U-bend) | 96511.2 and 21409.1 |
| ETSS #4 (Three Coil Plus Point, U-bend High Frequency) | 99997.1 |

Action Requests

| | | |
|---|---|---|
| AO 649000 | AO 649207 | AO 649959 |
| AO 649034 | AO 649209 | AO 650434 |
| AO 649207 | AO 649215 | AO 650500 |

Work Orders

WO C0197316/04 - ASME Code Section III, Class 2, "Install New ECCS Suction Void Header and Associated Piping and Valves"

Miscellaneous

Training and testing qualification/certification packages for NDE personnel

Document 51-1264530-12, "Diablo Canyon EPRI Appendix H Eddy Current Site Validation," dated November 2, 2005

EPRI Technical Report 1007904, "Steam Generator In Situ Pressure Test Guidelines," Revision 2

Steam Generator Degradation Assessment for "Diablo Canyon Unit 1 Refueling Outage 1R13 October 2005," Revision 0, dated 10-28-05

Technical Specification 5.5.9, revised in Amendment 182 to Facility Operating License DPR-80 (Unit 1) and Amendment 184 to Facility Operating License DPR-82 (Unit 2)

Letter from W. Rice to J. Portney, "Pacific Gas and Electric Company Diablo Canyon Units 1 and 2, Pressurizer Weld Material for Unit 1," December 19, 2003

Design Calculation –289, "Calculate Effective Degradation Years for Reactor Heads to Determine Examination Requirements," Revision 1

PG&E Letter DCL-05-067, "Relaxation Request for NRC Issuance of First Revised Order (EA-03-009) Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," May 27, 2005

October 26, 2005, NRC Letter to D. H. Oatley, "Diablo Canyon Power Plant, Unit No. 1 - Relaxation of Requirements Associated with First Revised Order (EA-03-009) dated February 20, 2004, Regarding Alternate Examination Coverage for Reactor Pressure Vessel Head Penetration Nozzles (TAC No. MC7071)"

Eddy Current Qualification Record, "Site Specific Performance Demonstration for Eddy Current Analysis of Steam Generator Tubing - November 2005," for the 85 eddy current analysts on site

**Section 1R12: Maintenance Effectiveness (71111.12)**

Action Requests

| | | | |
|---|---|---|---|
| A0647478 | A0647480 | A0647811 | A0648515 |
| A0648533 | A0648727 | A0649118 | |

Other Documents

Procedure MA1.ID17, "Maintenance Rule Monitoring Program," Revision 15
Procedure AD7, "Work Control," Revision 2
Drawing 102036, "Reactor Seismic Trip System," Revision 95

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

Action Requests

| | | | |
|---|---|---|---|
| A0648949 | A0648950 | A0648952 | A0650443 |
| A0652959 | A0653884 | A0653953 | |

Work Orders

C0195685

**Section 1R14: Operator Performance During Nonroutine Evolutions and Events (71111.14)**

Action Requests

A0644160 A0652421 A0653564

Procedures

AD7.DC8, "Work Control," Revision 20
MA1.DC11, "Risk Assessment," Revision 5A
OP B-3B:I, "Accumulators- Fill and Pressurize," Revision 23

**Section 1R15: Operability Evaluations (71111.15)**

Action Requests

| | | | | | |
|---|---|---|---|---|---|
| A0639938 | A0641553 | A0643132 | A0644041 | A0646914 | A0649118 |
| A0649293 | A0647625 | A0655600 | | | |

Drawings

107708, "Centrifugal Charging Pump 2-2 Lube Oil & Gear Oil Piping," Revision 84

Other Documents

Diablo Canyon Operability Evaluation Log Number 2005-251
Nonconformance Report N0002201

**Section 1R19: Postmaintenance Testing (71111.19)**

Action Requests

| | | | |
|---|---|---|---|
| A0650404 | A0652664 | A0652942 | A0655870 |

Procedures

STP M-11B, “Station Battery Condition Monitoring,” Revision 25
STP M-12A, “Vital Station Battery Modified Performance Test,” Revision 14
TQ2.ID4, “Training Program Implementation,” Revision 8

Work Orders

| | | | |
|---|---|---|---|
| C0194440 | C0198349 | C0201145 | R0259657 |

**Section 1EP3: Emergency Response Organization Augmentation Testing (71114.03)**

Procedures

TQ1, “Personnel Training and Qualification,” Revision 3
TQ1.ID3, “Non-accreditied Training Program Management,” Revision 5
OM10.ID4, “ERO Management,” Revision 7
OM10.DC2, “ERO On-Call,” Revision 4

Other Documents

Emergency Preparedness “Program of Instruction,” Revision 11

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

Action Requests

| | | | | | |
|---|---|---|---|---|---|
| A0580115 | A0613085 | A0616080 | A0620097 | A0620357 | A0620468 |
| A0631130 | A0631196 | A0632271 | A0632697 | A0632846 | A0632991 |
| A0634215 | A0634219 | A0634256 | A0634259 | A0634357 | A0634611 |
| A0634615 | A0634630 | A0634635 | A0635338 | A0635418 | A0635423 |
| A0637082 | A0637084 | A0638648 | A0638761 | A0638764 | A0638766 |
| A0640630 | A0641643 | A0642334 | A0642429 | A0645720 | A0646245 |
| A0646274 | A0646316 | A0646830 | A0647271 | A0648069 | A0648572 |

Nonconformance Reports

N0002199, “ERO Drill/Exercise Performance Not Meeting Station Goals,” 10/13/2005.
N0002200, “Inaccurate EP Drill/Exercise Performance Indicator Data,” 10/21/2005.

Procedures

OM10.ID1, “Maintaining Emergency Preparedness,” Revision 5

OM10.ID2, “Emergency Plan Revision and Review,” Revision 9

AWP EP-004, “10 CFR 50.54(q) Guidance,” Revision 1

AWP EP-005, “Determining Compensatory Measures for Equipment Affecting the Implementation of the DCPP Emergency Plan,” Revision 0

Self-Assessment Reports

Interim Compensatory Measures 1st Quarter 2005 Tabletop Drill
Charlie Team 3/12/2005 Rapid Response Tabletop Drill
Bravo Team 2nd Quarter 2005 Health Physics Drill
EPSA 2004-1, “Self Assessment of Emergency Action and Classification Levels”
EPSA 2004-2, “Self Assessment of Palo Verde June 14, 2004 Event”

Quality Assurance Assessments

Assessment No. 050200005, “2005 50.54(t) Audit”

Quality Performance Assessment Reports

QPAR (2nd Period) June 1 - October 24, 2004
QPAR (3rd Period) October 25 - December 31, 2004
QPAR (1st Period) January 1 - March 31, 2005
QPAR (2nd Period) April 1 - June 30, 2005

**Section 2OS1: Access Controls to Radiologically Significant Areas (71121.01)**

Corrective Action Documents

A0622516, A0622930, A0624274, A0638745, A0646778, A0649943, A0649193, A0649226, A0649316, A0649325

Audits and Self-Assessments

Quality Performance Assessment Reports: Third Period 2004, First Period 2005, Second Period 2005

2R12 Radiation Protection Assessment Report

Radiation Work Permits

| | |
|---|---|
| 05-0010 | Operations Activities |
| 05-1031 | 1R13 Regen HX Room Work |
| 05-1042 | 1R13 Primary SG Manway Work |
| 05-1050 | 1R13 RCP Pump Maintenance |

Procedures

| | |
|---|---|
| RCP D-211 | Control of Work in Radiologically Significant Areas, Revision 2 |
| RCP D-220 | Control of Access to High, Locked High, and Very High Radiation Areas, Revision 31 |
| RCP D-240 | Radiological Posting, Revision 16 |
| RCP D-500 | Routine and Job Coverage Surveys, Revision 21 |

**Section 4OA1: Performance Indicator Verification (71151)**

Procedures

AWP O-003, “NRC Performance Indicators: Occupational Exposure Control Effectiveness, Revision 3

OM10.DC1, “Emergency Preparedness Drills and Exercises,” Revision2A

AWP EP-001, “Emergency Preparedness Performance Indicators,” Revision 5

EP G-3, “Emergency Notification of Off-Site Agencies,” Revision 43, Attachment 6.1, “Instructions for the DCPP Emergency Notification Form”

EP R-2, “Release of Airborne Radioactive Materials Initial Assessment,” Revision 23

EP RB-10, “Protective Action Recommendations,” Revision 11

Other Documents

2005 Emergency Drill Schedule
Medical Services/ Evacuee Monitoring/Decontamination May 17-19, 2005
Annual Medical Drill, May 19, 2005
Alpha Team Dress Rehearsal, September 22, 2004
Alpha Team 2004 Plume Phase Ingestion Pathway Exercise, December 8, 2004

**Section 4OA2: Identification and Resolution of Problems (71152)**

Action Requests

| | | | | | |
|---|---|---|---|---|---|
| A0496806 | A0513448 | A0526037 | A0528837 | A0559173 | A0587674 |
| A0609629 | A0609710 | A0610421 | A0610937 | A0636258 | A0636984 |
| A0637470 | A0641418 | A0653564 | A0653644 | A0654587 | A0654716 |

Drawings

047284, “Piping Specification “S2",” Revision 16
106709 - Sheet 2, “Safety Injection,” Revision 44

Procedures

PEP V-PIV, “Cumulative RCS Pressure Isolation Valve (PIV) Leakage,” Revisions 0 and 1
TP TB-0522, “Determination of Leak Path for SI Header Pressurization,” Revision 0

Other Documents

Operational Decision Making Report, “Unit 1 Safety Injection pump discharge header pressure is increasing above accumulator pressure,” dated November 30 and December 21, 2005

## LIST OF ACRONYMS

| | |
|---|---|
| ADAMS | agency document and management system |
| AR | action request |
| ASME | American Society of Mechanical Engineers |
| CAP | corrective action program |
| CFR | Code of Federal Regulations |
| EPRI | Electric Power Research Institute |
| ECCS | Emergency Core Cooling System |
| FSAR | Final Safety Analysis Report |
| HELB | high-energy line break |
| IMC | Inspection Manual Chapter |
| LER | Licensee Event Report |
| NCV | noncited violation |
| NEI | Nuclear Energy Institute |
| NRC | Nuclear Regulatory Commission |
| PG&E | Pacific Gas and Electric Company |
| RCS | reactor coolant system |
| RHR | residual heat removal |
| SDP | Significance Determination Process |
| SSC | structure, system, and component |
| TS | Technical Specifications |
| WEXTEX | Westinghouse explosive tube expansion |