UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

August 14, 2006

John S. Keenan
Senior Vice President - Generation
and Chief Nuclear Officer
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SUBJECT: DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000275/2006003 AND 05000323/2006003

Dear Mr. Keenan:

On June 30, 2006, the U.S. Nuclear Regulatory Commission completed an inspection at your Diablo Canyon Power Plant, Units 1 and 2, facility. The enclosed integrated report documents the inspection findings that were discussed on July 12, 2006, with Mr. James Becker and members of your staff.

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

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

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

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Inspection Report 05000275/2006003
and 05000323/2006003
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RIV:RI:DRP/B	SRI	DRS/EB1	DRS/EB2	DRS/OB
TAMcConnell	TWJackson	JAClark	LJSmith	ATGody
E - WBJones	***T - WBJones***	***/RA/***	***/RA/***	***/RA/***
8/11/06	8/1/06	8/3/06	8/1/06	8/2/06

DRS/PSB	C:DRP/B		
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8/3/06	8/14/06		

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Enclosure

REGION IV

Dockets:	50-275, 50-323
Licenses:	DPR-80, DPR-82
Report:	05000275/2006003 05000323/2006003
Licensee:	Pacific Gas and Electric Company (PG&E)
Facility:	Diablo Canyon Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	April 1 through June 30, 2006
Inspectors:	T. Jackson, Senior Resident Inspector T. McConnell, Resident Inspector S. Graves, Reactor Inspector P. Gage, Senior Operations Engineer R. Lantz, Senior Emergency Preparedness Inspector J. Tapia, Senior Reactor Inspector B. Tharakan, Health Physicist
Approved By:	W. B. Jones, Chief, Project Branch B Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000275/2006-003, 05000323/2006-003; 4/1/06 - 6/30/06; Diablo Canyon Power Plant Units 1 and 2; Inservice Inspection Activities, Operability Evaluations, Refueling and Outage Activities, and Access Control to Radiologically Significant Areas.

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

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A self-revealing, noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, was determined for the failure of operations personnel to promptly identify a condition adverse to quality. Specifically, on November 27, 2005, operators failed to document, in the corrective action program, an unexpected level drop in Accumulator 1-3. Failure to enter the occurrence into the corrective action program precluded actions that would have addressed similar conditions that resulted in a subsequent event involving an unexpected level drop and water hammer associated with Accumulator 2-3, which occurred on May 21, 2006. This issue was entered into Pacific Gas and Electric Company's corrective action program as Action Request A0669468.

  The finding is greater than minor because it is associated with the Mitigating Systems 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," Phase 1 Worksheet, the finding is determined to be of very low safety significance because the finding did not represent a loss of a safety function, an actual loss of a safety-related train for greater than its Technical Specification allowed outage time, or screen as potentially risk-significant due to seismic, fire, flooding, or severe weather initiating events. The finding had a crosscutting aspect in the area of problem identification and resolution because operations personnel failed to promptly identify, in the corrective action program, the unexpected level drop in Accumulator 1-3 (Section 1R15).

- Green. An NRC-identified, noncited violation of Technical Specification 5.4.1.a for an inadequate procedure, Procedure OP A-2:II, "Reactor Vessel - Draining the RCS to the Vessel Flange - With Fuel in Vessel," Revision 33A. Specifically, on April 20, 2006, while operators depressurized the reactor coolant system, with water level 2 feet below the reactor vessel flange, the two required level instruments, wide-range reactor vessel refueling level indication system and LI-400, read 15 inches higher than actual reactor vessel water level. The inspectors determined that the procedure was not adequate because prior operating experience had not been incorporated into the procedure that demonstrated the level instruments would read nonconservatively during the reactor coolant system depressurization. Also, Procedure OP A-2:II did not have criteria that alerted operators to abnormal level instrument deviations that may be caused by phenomenon outside of the level deviations expected by the reactor coolant system depressurization. Pacific Gas and Electric Company has planned to evaluate potential changes to Procedure OP A-2:II and reactor coolant system water level instrumentation when used during reactor coolant system depressurization. This issue was entered into Pacific Gas and Electric Company's corrective action program as Action Requests A0664484, A0672419, and A0672422.

The finding is greater than minor because it is associated with the Mitigating Systems Cornerstone attribute of procedure quality 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, Appendix G, Attachment 1, Checklist 3, the finding is determined to be of very low safety significance since an optional set of instrumentation provided accurate reactor coolant system level indication and there was no loss of reactor coolant system inventory control. The finding had a crosscutting aspect in the area of human performance for resources because Pacific Gas and Electric Company failed to ensure the adequacy of procedures used for reactor vessel level monitoring to ensure nuclear safety (Section 1R20).

- Green. An NRC-identified noncited violation of 10 CFR Part 50, Criterion XVI, "Corrective Actions," was determined for the failure to prevent recurrence of a similar failures, that occurred between 2003 and 2006, of Limitorque SMB-000 actuators in the auxiliary feedwater system. Pacific Gas and Electric Company staff failed to adequately troubleshoot and provide for timely corrective actions regarding auxiliary feedwater control valves that failed due to high actuator torque switch resistance. This finding was entered into Pacific Gas and Electric Company's corrective action program as Nonconformance Report N0002205.

  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 the Inspection Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to be of 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 finding had a crosscutting aspect in the area of problem identification and resolution since Pacific Gas and Electric Company staff failed to adequately trend, assess, and troubleshoot previous Limitorque SMB-000 actuator failures (Section 4OA5.3).

Cornerstone: Barrier Integrity

- Green. An NRC-identified noncited violation of Technical Specification 5.4.1 was identified because Pacific Gas and Electric Company failed to follow the procedure for ensuring that welding preheat temperatures were verified prior to welding. Specifically, during the replacement of Component Cooling Water Valves 279 and 280, which provide cooling to the reactor vessel support pads, Pacific Gas and Electric Company failed to verify that the minimum welding preheat temperature of 50°F was met, and could not demonstrate that the ambient temperature was greater than 50°F. Pacific Gas and Electric Company surveyed the area and entered the finding into their corrective action program as Action Request A0665588.

  The finding was greater than minor because it was associated with the human performance attribute of the Barrier Integrity Cornerstone and impacted the cornerstone objective of providing reasonable assurance that physical design barriers, in this case the reactor coolant system, protect the public from radionuclide releases caused by accidents or events. The finding was determined to be of very low safety significance based on management review of the plant conditions at the time the performance deficiency occurred (defueled) and the condition was evaluated prior to the plant entering Mode 5 (Section 1R08).

Cornerstone: Occupational Radiation Safety

- Green. The inspectors identified a noncited violation of 10 CFR 20.1501(a) because Pacific Gas and Electric Company failed to survey to determine the extent and magnitude of radiation levels and evaluate the radiological hazards. Specifically, on April 18, 2006, the inspectors identified elevated radiation levels near two chemical volume control system valves located in a hallway on the 100-foot elevation of Unit 2. Pacific Gas and Electric Company confirmed elevated radiation levels near the valves were as high as 200 millirem per hour on contact and 28 millirem per hour at 30 centimeters. Pacific Gas and Electric Company surveyed the area and entered the finding into their corrective action program as Action Request 0665039.

  The finding was greater than minor because it was associated with the Occupational Radiation Safety Cornerstone attribute of Exposure Control and Monitoring and affected the cornerstone objective to ensure the adequate protection of a worker’s health and safety from exposure to radiation because workers could have unknowingly received additional radiation exposure. When going through the Occupational Radiation Safety Significance Determination Process, the finding was determined to be of very low safety significance because it was not an as low as is reasonably achievable finding. There was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised. The finding also had crosscutting aspects associated with human performance because adequate resources were not established for the survey requirements (Section 2OS1).

REPORT DETAILS

Summary of Plant Status

Diablo Canyon Unit 1 operated at 100 percent power for this inspection period.

Diablo Canyon Unit 2 began this inspection period at 100 percent power and entered Refueling Outage 2R13 on April 17, 2006. Unit 2 entered Mode 6 (Refueling) for core offload operations on April 20, which was completed on April 25. Unit 2 entered Mode 6 on May 11 when operators began reloading fuel into the core, and then entered Mode 5 (Cold Shutdown) on May 17 when maintenance personnel tensioned the reactor vessel head. Operators commenced a heatup of the reactor coolant system (RCS), and Unit 2 entered Mode 4 (Hot Shutdown) on May 21 and Mode 3 (Hot Standby) on May 23. On May 24, operators proceeded with reactor startup, entering Mode 2 (Startup). Operators increased reactor power, and Unit 2 entered Mode 1 (Power Operations) on May 25. On May 25, Unit 2 was paralleled to the grid, ending Refueling Outage 2R13. On May 26, the operators removed the unit from the grid due to a seal rub on the low pressure turbine. The main turbine was subsequently paralleled to the grid on the same day. Operators continued to raise reactor power and, on June 5, Unit 2 reached 100 percent power. On June 21, Unit 2 reduced power to 82 percent to perform maintenance on high pressure turbine governor Valve FCV-142. Unit 2 was returned to 100 percent power on the same day and remained at that power level for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignments (71111.04)

.1 Partial System Walkdowns

a. Inspection Scope

The inspectors: (1) walked down portions of the three below listed risk-important systems 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 walkdown to the Final Safety Analysis Report (FSAR) Update and corrective action program (CAP) to ensure problems were being identified and corrected.

- April 17, 2006: Unit 2, RCS piping
- May 5, 2006: Unit 2, Vital Batteries 2-1, 2-2, and 2-3
- June 28, 2006: Unit 1, Safety Injection Pump 1-1

Documents reviewed by the inspectors included:

- Procedure OP B-3A:II, “Safety Injection System Alignment Verification for Plant Startup,” Revision 23,

- Drawing 106709, “Safety Injection,” Sheet 4, Revision 54

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

.2 Complete System Walkdown

a. Inspection Scope

The inspectors: (1) reviewed plant procedures, calculations, the FSAR Update, Technical Specifications (TSs), and vendor manuals to determine the impact of ultra-low sulfur diesel fuel on the capability of the diesel engine generators; (2) reviewed outstanding design issues, operator workarounds, and FSAR Update documents to determine if open issues affected the functionality of the diesel engine generators; and (3) verified that Pacific Gas and Electric Company (PG&E) was identifying and resolving equipment alignment problems. Documents reviewed by the inspectors are listed in the attachment.

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 six 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.

- April 10, 2006: Unit 2, 140 foot turbine building

- April 14, 2006: Unit 2, 64 foot auxiliary building
- May 1, 2006: Units 1 and 2, intake structure
- May 2, 2006: Unit 2, Containment Fire Zones 1A, 1B, and 1C
- May 2, 2006: Unit 1, 85 foot auxiliary building
- May 8, 2006: Security diesel engine generator building

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed six 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.

- April 2, 2006: Units 1 and 2, 500 kV switchyard Pullboxes W-3 and W-4

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 Electric Power Research Institute 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 -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)

.1 Inspection Activities Other Than Steam Generator Tube Inspections, Pressurized Water Reactor Vessel Upper Head Penetration Inspections, Boric Acid Corrosion Control

a. Inspection Scope

The procedure requires review of two or three types of nondestructive examination (NDE) activities (volumetric, surface, and visual.) The inspector reviewed multiple examples of all three types.

The procedure requires review of one or two examinations from the previous outage with recordable indications that were accepted for continued service. The inspector reviewed one such examination (Residual Heat Removal System Piping Weld RB-119-II).

If PG&E completed welding on the pressure boundary for Class 1 or 2 systems since the beginning of the previous outage, the procedure requires verification for one-to-three welds that acceptance and preservice examinations were done in accordance with American Society of Mechanical Engineers (ASME) Code. The inspector verified one such weld (Safety Injection System Weld 2SI-119-8III).

The procedure requires verification that one or two ASME Section XI Code repairs or replacements meet Code requirements. The inspector verified two Section XI repairs (replacement of Component Cooling Water Valves 2-279 and 2-280 and replacement of Residual Heat Removal Valve 2-8742B).

The inspector verified, through direct observation or record review, that ultrasonic, eddy current, liquid penetrant, radiographic, or visual examinations of the components listed below were performed in accordance with ASME Code requirements.

System	Component/Weld Identification	Examination Method
Feedwater	Steam Generator 1 Feedwater Supply Hanger 2037-7V	Visual (VT-3)
Auxiliary Feedwater (AFW)	AFW Pump 2-1 Discharge Header Hanger 414-505R	Visual (VT-3)
AFW	AFW Pump 2-1 Discharge Header Hanger 414-386R	Visual (VT-3)
AFW	AFW Supply Hanger 42-42R	Visual (VT-3)
Chemical Volume Control System	CVCS-2-8388C, FW-2	Radiographic
Feedwater	K16-555-16/Integral Attachments	Magnetic Particle & Ultrasonic
Feedwater	K16-557-16	Magnetic Particle & Ultrasonic
Reactor Coolant	S6-959-2 SPL WIB-503	Liquid Penetrant
Reactor Coolant	S6-959-2 SPL WIB-1009	Liquid Penetrant
Reactor Vessel	Circumferential Weld 9-201	Ultrasonic
Reactor Vessel	Loop 2 Outlet Safe-end	Ultrasonic

During the review of each examination, the inspector verified that the correct NDE procedures were used, that examinations and conditions were as specified in the procedure, and that test instrumentation or equipment was properly calibrated and within the allowable calibration period. The inspector also reviewed documentation such as ultrasonic and eddy current inspection records to determine if the indications revealed by the examinations were compared against the ASME Code specified acceptance standards. This review also determined that indications were appropriately dispositioned.

The inspector verified the NDE certifications of those personnel observed performing examinations or identified during review of completed examination packages.

The inspector also reviewed the replacement of four valves performed in accordance with ASME Section XI. During the replacement of two component cooling water valves that supply cooling to the reactor vessel support pads, the inspector found that PG&E did not verify the minimum preheat temperature prior to welding.

The minimum sample requirements of the inspection procedure were satisfied.

b. Findings

Introduction: A Green, noncited violation (NCV) of TS 5.4.1.a was identified for failure to follow the procedure for ensuring that welding preheat temperatures were verified prior to welding. Specifically, on April 26, 2006, during the replacement of Component Cooling Water Valves 279 and 280, which provide cooling to the reactor vessel support pads, PG&E failed to verify that the minimum welding preheat temperature of 50°F was met and PG&E could not demonstrate that the ambient temperature was greater than 50°F.

Description: The replacement of Valves 279 and 280 was performed in accordance with Work Order CO196956, which referenced Welding Procedure Specification 5, "Welding of P1 Materials with GTAW and/or SMAW," Revision 8; Nuclear Welding Control Manual Procedures GWS-ASME,"ASME General Welding Standard," Revision 8; and WI-1, "Visual Inspection of Welds," Revision 7. Welding Procedure Specification 5 lists a minimum preheat temperature of 50°F as an essential variable. Section 4.5 of GWS-ASME states that preheat temperature shall be verified with thermocouples or temperature indicating crayons or contact pyrometers outside the weld joint but near the weld area. Section 6.7 of Procedure WI-1 states that verification of preheat temperature is not mandatory for welds that require a minimum preheat of 50°F, if it can be demonstrated that the ambient temperature is greater than 50°F. During the replacement of Valves 279 and 280, PG&E did not verify the preheat temperature prior to welding. The containment building was open to the environment and no ambient temperature measurement was performed to demonstrate that the ambient temperature was greater than 50°F.

Analysis: The performance deficiency associated with this finding is a failure to follow procedures. This deficiency impacted the Barrier Integrity Cornerstone and, as described in Inspection Manual Chapter (IMC) 0612, Appendix B, the finding was considered more than minor since it affected the cornerstone objective of providing reasonable assurance that physical design barriers, in this case the RCS, protect the public from radionuclide releases caused by accidents or events. Specifically, the failure to ensure minimum preheat temperature prior to welding affected the cornerstone attribute of human performance and its impact on maintaining functionality of the RCS because not adequately controlling the welding process can lead to weld failures. Minimum preheat temperature is defined in Section IX of the ASME Code as an essential variable which can affect the mechanical properties of a weldment. For carbon steels or low alloy steels, the failure to observe the specified minimum preheat temperature could result in too rapid cooling and the formation of martensite, a brittle structure. Rapid cooling could also impede the ability of the weldment to evolve gases introduced or formed during the welding operation, leading to hydrogen embrittlement. The finding was determined to be of very low safety significance based on management review of the plant conditions at the time the performance deficiency occurred (defueled) and the condition was evaluated prior to the plant entering Mode 5.

Enforcement: TS 5.4.1.a requires that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Appendix A, Section 9, lists procedures for performing maintenance activities, such as welding. Welding Procedure Specification 5 and Nuclear Welding Control Manual Procedures GWS-ASME and WI-1 require that minimum preheat temperature be verified prior to welding. Contrary to the above, on April 24, 2006, PG&E failed to follow these procedures by not verifying the preheat temperature nor that the ambient temperature was above 50°F before beginning welding on Component Cooling Water Valves 279 and 280. Because the failure to follow procedures was of very low safety significance and has been entered into the CAP as Action Request (AR) A0665588, this violation is being treated as an noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/06-03-01, Failure to Follow Procedures for Welding.

.2 Pressurized Water Reactor Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

The inspector reviewed PG&E's reactor vessel upper head penetration (VUHP) nozzle inspection activities implemented in accordance with the requirements of NRC Order EA-03-009, issued on February 20, 2004. PG&E's nonvisual NDE technique was a surface examination using ultrasonic and eddy current testing of the wetted surface of the VUHP nozzle base material and the J-groove weld.

The inspector observed a sample of NDE performed on the vessel head from remote video feeds at the collection and analysis stations. The inspector examined ultrasonic and eddy current data collected. A review of the NDE examination procedures used was also performed to confirm that they were consistent with the ASME Code and that the equipment and calibration requirements were consistent with that used in mockup demonstrations on simulated actual cracking. The inspector also reviewed records indicating the extent of inspection for each penetration nozzle, including documents which resolved interference or masking issues. Specifically, the inspector verified that PG&E achieved ultrasonic testing coverage to the maximum extent possible. In all cases, the coverage was from 2 inches above the J-groove weld down to the lowest elevation that could be practically inspected on each nozzle with the ultrasonic testing probe being used with a minimum required inspection distance of 0.3 inches below the J-groove weld. This criteria was specified in an NRC approved alternate examination criteria for 78 VUHP nozzles.

For all activities reviewed, the inspector determined that the activities were performed in accordance with the requirements of the NRC Order. No indications or defects were detected. There had not been any indications previously identified which had been accepted for continued service.

The minimum sample requirements of the inspection procedure were satisfied.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control Inspection Activities (Pressurized Water Reactors)

a. Inspection Scope

The inspector reviewed a sample of boric acid corrosion control walkdown visual examination activities. The inspector determined that PG&E's visual inspections emphasized locations where boric acid leaks could cause degradation of safety significant components.

The inspector reviewed three engineering evaluations performed for boric acid found on RCS piping and components. The review verified that ASME Code wall thickness requirements were maintained and that the degraded conditions were properly entered and dispositioned in PG&E's CAP.

The minimum sample requirements of the inspection procedure were satisfied.

b. Findings

No findings of significance were identified.

.4 Steam Generator Tube Inspection Activities

a. Inspection Scope

The inspector verified that the steam generator tube eddy current examination scope and expansion criteria met the TS requirements, industry guidelines, and commitments made to the NRC. The inspector confirmed that known areas of potential degradation based on site-specific and industry experience were included in the scope of the inspection. The inspector observed the collection and analysis of eddy current data by contractor personnel and verified that: (1) the eddy current probes being utilized were appropriate for identifying the expected types of indications, (2) probe position location verification was being performed, (3) calibration requirements were being adhered to, and (4) probe travel speed was in accordance with procedural requirements.

The inspector verified that PG&E compared flaws detected during the current outage against the previous outage data and that appropriate repair criteria was specified. One hundred percent of all steam generator tubes were inspected during this outage. The inspector noted that the number of tubes required to be plugged was consistent with predictions made prior to the start of the outage. Tube plugging activities during the inspection were in accordance with procedural requirements and were within the allowable limits for tube plugging.

The minimum sample requirements of the inspection procedure were satisfied.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Quarterly Inspection

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 a positive displacement pump overcurrent trip, loss of a vital 4 kV bus, an earthquake, and an anticipated transient without scram.

Documents reviewed by the inspectors included Lesson FRS1-A, Attachment 2, "Simulator Event Sequence," Revision 14.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Biennial Inspection

a. Inspection Scope

Following the completion of the annual operating examination testing cycle, which ended the week of April 4, 2006, the inspectors reviewed the overall pass/fail results of the annual individual job performance measure operating tests and simulator operating tests administered by PG&E staff during the operator licensing requalification cycle. Sixteen separate crews participated in simulator operating tests, and 79 licensed operators took the job performance measure operating tests. All of the crews tested passed the simulator portion of the annual operating test. All of the licensed operators, except one, passed the job performance measure portion of the examination. The licensed operator was successfully remediated prior to returning to shift. These results were compared to the thresholds established in IMC 609, Appendix I, "Operator Requalification Human Performance Significance Determination Process."

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 one below listed maintenance activity 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 TSs.

- May 1, 2006: Units 1 and 2, Containment isolation valves

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

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 one 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) that PG&E identified and corrected problems related to maintenance risk assessments.

- April 5, 2006: Unit 2; Diesel Fuel Oil Transfer Pump 0-1 and Electrohydraulic Pump 2-2 preventive maintenance, 500 kV Circuit Breaker 542 replacement, and Morro Bay to Diablo Canyon 230 kV line outage due to fiber optic cable installation.

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

a. 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.

- April 2, 2006: Unit 1, Diesel Engine Generator 1-3 voltage regulator failure

- June 3, 2006: Unit 1, Failure of rod control system to manually withdraw Bank D control rods from core

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

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 nonroutine 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 nonroutine evolutions sampled.

- April 23, 2006: Unit 2, Fuel handling cart position resolver failed while a fuel assembly was in motion

- May 4, 2006: Units 1 and 2, Magnitude 2.8 earthquake approximately 6 km west northwest of Diablo Canyon Power Plant

- May 25, 2006: Unit 2, Auxiliary Transformer 2-1 sudden pressure trip

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. 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 significance determination process 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.

- April 14, 2006: Unit 1, Condensate storage tank epoxy delamination
- April 14, 2006: Unit 2, Residual heat removal system weld flaw
- May 8, 2006: Unit 2, Station vital inverters
- May 9, 2006: Units 1 and 2, Feedwater ultrasonic flow meter data scatter
- May 21, 2006: Unit 2, Accumulator 2-3 discharge line water hammer

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed five samples.

b. Findings

Introduction: A self-revealing, NCV of 10 CFR Part 50, Appendix B, Criterion XVI, was determined for the failure of operators to promptly identify a condition adverse to quality. Specifically, operators failed to document in the CAP an unexpected level drop in Accumulator 1-3 during Refueling Outage 1R13. Failure to enter the occurrence into the CAP precluded corrective actions that would have prevented the unexpected level drop in Accumulator 2-3 and the water hammer of its discharge piping.

Description: On May 21, 2006, with Unit 2 in Mode 4 and reactor coolant system pressure at 935 psig, operators opened Accumulator 2-3 Discharge Valve SI-2-8808C and subsequently Accumulator 2-3 level unexpectedly dropped from 67 to 57 percent. At the same time, operators received a Reactor Coolant Pump 2-3 vibration alarm and audible indications of a water hammer from inside containment. PG&E staff concluded that a water hammer had occurred inside the discharge piping of Accumulator 2-3. As immediate corrective actions, PG&E staff visually walked down Accumulator 2-3 discharge piping and supports, verified operability of the discharge piping seismic snubbers, and verified the absence of voids in other portions of Units 1 and 2 emergency core cooling system piping. Upon review of Accumulator 2-3 piping layout, PG&E staff found that there were no vent points in the accumulator discharge piping between motor-operated discharge Valve SI-2-8808C and discharge check Valve SI-2-8956C. Additionally, there were no procedures that specifically addressed the venting of the discharge line. The inspectors calculated approximately 83 feet of 10-inch pipe between the two valves, which equated to an approximate volume of 34.7 ft^3. PG&E initiated a root cause investigation under Nonconformance Report N0002207 to determine the cause(s) and appropriate corrective actions for the water hammer event.

While investigating the cause of the water hammer event, PG&E staff learned that a similar event had occurred with Accumulator 1-3 during Refueling Outage 1R13. On November 27, 2005, operators opened Accumulator 1-3 Discharge Valve SI-1-8808C and observed an approximate 7 percent level drop in the accumulator. However, there were no corresponding indications of a water hammer, such as an audible noise or reactor coolant pump vibration alarms. Although the level drop was recorded in the operator logs, operators failed to enter the unexpected occurrence into the CAP. PG&E staff has since entered the occurrence as AR A0669453.

The inspectors determined that the failure to address the Unit 1 accumulator level drop precluded corrective actions from being taken to prevent a recurrence of the event on Unit 2. Specifically, PG&E staff should have identified the voided condition after the Unit 1 accumulator level drop and that there was potential for voiding of the accumulator discharge piping due to the absence of vent points and procedures for venting.

<u>Analysis</u>: The performance deficiency associated with this finding involved a failure of operations personnel to promptly identify a condition adverse to quality and enter it into the CAP. The performance deficiency was self-revealing based on the second event initiating the licensee's review of the cause and subsequent identification that the event had occurred on Unit 1 also. The finding is greater than minor because it is associated with the Mitigating Systems 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 IMC 0609, "Significance Determination Process," Appendix A, Phase 1 Screening Worksheet, the finding is determined to be of very low safety significance because the finding did not represent a loss of safety function, an actual loss of a safety-related train for greater than its TS allowed outage time, or screen as potentially risk-significant due to seismic, fire, flooding, or severe weather initiating events. The finding had a crosscutting aspect in the area of problem identification and resolution because operations personnel failed to promptly identify, in the CAP, the unexpected level drop in Accumulator 1-3.

<u>Enforcement</u>: 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to this, between November 27, 2005, and May 24, 2006, operations personnel failed to assure that a condition adverse to quality was promptly identified. Specifically, on November 27, 2005, the level in Accumulator 1-3 unexpectedly dropped 7 percent when operators opened its discharge valve. Although operators documented the event in their logs, they failed to enter the occurrence into the CAP. Subsequently, no corrective actions were taken. On May 21, 2006, when the discharge valve on Accumulator 2-3 was opened, its level unexpectedly dropped by 10 percent and a water hammer occurred in its discharge piping. The apparent cause of the failure to promptly identify a condition adverse to quality was that operators did not recognize the significance of the Accumulator 1-3 level drop. Corrective actions include additional training of operations personnel regarding the importance of promptly identifying conditions adverse to quality. Because the finding is of very low safety significance and has been entered into PG&E's CAP as AR A0669468, this violation is being treated as an NCV consistent with Section VI.A of

the Enforcement Policy: NCV 50-275/06-03-02, Failure to Promptly Identify Voiding in Accumulator Discharge Line.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed key affected parameters associated with energy needs, materials/replacement components, timing, heat removal, control signals, equipment protection from hazards, operations, flowpaths, pressure boundary, ventilation boundary, structural, process medium properties, licensing basis, and failure modes for the one modification listed below. The inspectors verified that: (1) modification preparation, staging, and implementation did not impair emergency/abnormal operating procedure actions, key safety functions, or operator response to loss of key safety functions; (2) postmodification testing maintained the plant in a safe configuration during testing by verifying that unintended system interactions will not occur, SSC performance characteristics still met the design basis, the appropriateness of modification design assumptions, and the modification test acceptance criteria has been met; and (3) PG&E has identified and implemented appropriate corrective actions associated with permanent plant modifications.

- May 19, 2006: Removal of mesh over the residual heat removal suction point in the containment recirculation sump and modifications to the reactor cavity door to address recirculation sump debris loading concerns

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the nine 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) evaluated 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 realigned, 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.

- April 18, 2006: Unit 2, Containment Spray Pump 2-1 and 2-2
- April 20, 2006: Unit 2, Source Range Nuclear Instrument 31
- May 2, 2006: Unit 2, Component Cooling Water Pump 2-3
- May 2, 2006: Unit 2, Vital Inverter IY-21
- May 2, 2006: Unit 2, 4kV Vital Bus "H" Switchgear
- May 5, 2006: Unit 2, Auxiliary Saltwater Pump 2-2
- May 11, 2006: Unit 2, Centrifugal Charging Pump 2-1
- May 12, 2006: Unit 2, Fuel transfer cart position resolver
- May 18, 2006: Unit 2, Auxiliary Transformer 2-1

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed nine samples.

b. Findings

No findings of significance were identified.

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) RCS 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 debris and supports, braces, and snubbers for evidence of excessive stress, water hammer, or aging. Documents reviewed by the inspectors included the Unit 2 Refueling Outage 2R13 Outage Safety Plan.

The inspectors completed one sample.

b. Findings

Introduction: An NRC-identified NCV of TS 5.4.1.a was determined for an inadequate procedure, Procedure OP A-2:II, "Reactor Vessel - Draining the RCS to the Vessel Flange - With Fuel in Vessel," Revision 33A. Specifically, the procedure did not address the reactor vessel level instrumentation required by the procedure deviated from actual level by approximately 15 inches when the time to boiling in the reactor vessel was approximately 20 minutes, if shutdown cooling were lost.

Description: One action to ensure the integrity of shutdown cooling by operators was to prevent reactor vessel water level from dropping below the 107.5 foot elevation, where vortexing of the shutdown cooling pumps may occur. To monitor reactor vessel water level, operators used three RCS water level instruments when above 112 foot elevation. The first level instrument was the wide-range reactor vessel refueling level instrument system (RVRLIS), which consisted of two pressure transmitters measuring the differential pressure across the RCS. The reference leg transmitter was located at the top of the pressurizer and the variable leg transmitter was located at the Loop 4 crossover leg. The second level instrument was LI-400, which is a clear standpipe with internal flags that indicate water level. LI-400 had essentially the same range and instrument tap locations as wide-range RVRLIS. The third level instrument was the narrow-range RVRLIS, which also consisted of two pressure transmitters that measured the differential pressure across the upper portion of the reactor vessel. The reference leg transmitter was located at the reactor head vent, and the variable leg transmitter was located at the Loop 3 hot leg.

On April 20, 2006, in preparation for reactor vessel head removal, operators lowered water level in the reactor vessel to the 112 foot elevation (2 feet below the vessel flange) using Procedure OP A-2:II. At the 112 foot elevation, the time for water in the reactor vessel to boil, if shutdown cooling were lost, was reduced to approximately 20 minutes. During the RCS draindown to the 112 foot elevation, Procedure OP A-2:II required operators to maintain wide-range RVRLIS and LI-400 level indications in agreement by +/- 9 inches. However, Procedure OP A-2:II did not require the instruments to agree once level reached the 112 foot elevation. Additionally, Procedure OP A-2:II allowed operators to place into service narrow-range RVRLIS and required it to read within +/- 4 inches of LI-400 initially, but not for the duration of the RCS depressurization which was to follow.

Once operators reached the 112 foot elevation and placed narrow-range RVRLIS in service, they began to depressurize the RCS according to Procedure OP A-2:II. During the depressurization, operators observed that both required instruments, wide-range RVRLIS and LI-400 began to show increasing level, while the optional narrow-range RVRLIS water level remained stable at 112 feet. The deviation between narrow-range RVRLIS and the other two instruments grew to approximately 15 inches before levels stabilized. PG&E staff determined that a pressure differential existed between the gas spaces of the pressurizer and reactor vessel. The RCS was depressurized via the pressurizer relief tank with an approximate 1-inch outer diameter pipe. The communication path between the pressurizer and reactor vessel gas spaces was also an approximate 1-inch outer diameter pipe. Despite the communication pathway, the depressurization activities would cause the pressurizer gas space to have a lower pressure than the reactor vessel gas space. Subsequently, the wide-range RVRLIS and LI-400 instruments would read lower (reference from the pressurizer gas space) than narrow-range RVRLIS (referenced from the reactor vessel gas space).

The inspectors reviewed operating experience from both the Diablo Canyon Power Plant and the nuclear industry. Specifically, the inspectors reviewed Generic Letter 88-17, “Loss of Decay Heat Removal.” Generic Letter 88-17 specifically addressed reduced inventory evolutions, which is defined as 3 feet below the reactor vessel flange. While the evolution on April 20, 2006, involved an RCS level that was only 2 feet below the reactor vessel flange, the time-to-boiling estimate was short (approximately 20 minutes). Therefore, the inspectors determined that many of the recommendations in Generic Letter 88-17 could be considered as operating experience for this evolution. An example of a recommendation was the consideration of various phenomena that could affect level instrumentation, including the inability of gas spaces to communicate if the RCS legs are full of water. Also, Generic Letter 88-17 recommended reliable, accurate RCS water level information for operators whenever approaching or operating in a condition where a loss of level can lead to loss of decay heat removal. Through discussions with operators and a review of Procedure OP A-2:II, the inspectors observed that Diablo Canyon Power Plant had operating experience that would demonstrate that the level instrumentation would tend to deviate when the RCS was being depressurzied.

The inspectors determined that PG&E staff had failed to adequately maintain Procedure OP A-2:II. First, wide-range RVRLIS and LI-400 were the required RCS level instruments during the RCS depressurization at the 112 foot elevation, even though these instruments would tend to read nonconservatively due to the pressure differences in the gas spaces of the pressurizer and the reactor vessel. The inspectors determined that an adequate review of operating experience would have demonstrated that these level instruments were nonconservative for the depressurization evolution. Second, Procedure OP A-2:II did not have criteria regarding the performance of the RCS level instruments during the RCS depressurization evolution. Although operators knew that RCS level instruments may deviate from each other during the depressurization, there was no criteria that would have given operators information that abnormal level deviations were occurring and may be indicative of unexpected equipment operation, problems, or phenomenon. Generic Letter 88-17 had recommended that licensees consider various phenomenon that could affect level instrumentation and that reliable and accurate RCS level information be provided to the operator to the extent possible when approaching conditions that could challenge loss of decay heat removal.

Analysis: The performance deficiency associated with this finding involved the failure to maintain Procedure OP A-2:II. The finding is greater than minor because it is associated with the Mitigating Systems Cornerstone attribute of procedure quality 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, Appendix G, Attachment 1, Checklist 3, the finding is determined to be of very low safety significance since one set of instrumentation provided accurate RCS level indication and there was no loss of RCS inventory control. The finding had a crosscutting aspect in the area of human performance for resources because PG&E failed to ensure the adequacy of the procedures used for reactor vessel level monitoring to ensure nuclear safety.

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 2, requires procedures for refueling operations. Contrary to this, Procedure OP A-2:II, "Reactor Vessel - Draining the RCS to the Vessel Flange - With Fuel in Vessel," was inadequate because the procedures required the wide-range RVRLIS and LI-400 to be in service during RCS depressurization, despite operating experience that demonstrated these instruments would read nonconservatively. Additionally, Procedure OP A-2:II did not have criteria that alerted operators to abnormal level instrument deviations that may be caused by phenomena outside of the level deviations expected by the RCS depressurization. PG&E has planned to evaluate potential changes to Procedure OP A-2:II and RCS water level instrumentation when used during RCS depressurization. Because the finding is of very low safety significance and has been entered into PG&E's CAP as ARs A0664484, A0672419, and A0672422, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 50-323/06-03-03, Inadequate Refueling Procedure for Draining and Depressurizing the Reactor Coolant System.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the FSAR Update, procedure requirements, and TS to ensure that the six 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 (PI) 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.

- April 17, 2006: Unit 1, Procedure STP M-9I, "Diesel Generator Start and Load Tracking," Revision 19, and STP M-9A, "Diesel Engine Generator Routine Surveillance Test," Revision 70

- April 19, 2006: Unit 2, Procedures STP P-CSP-A22, "Comprehensive Testing of Containment Spray Pump 2-2," Revision 2 and STP P-CSP-A21, "Comprehensive Testing of Containment Spray Pump 2-1," Revision 1

- May 1, 2006: Unit 2, Procedure STP 102, "Test of Backup Nitrogen Accumulator System to Spray Valves and Charging Valves 8145, 8146, and 8147," Revision 23

- May 8, 2006: Unit 2, Procedure STP MP-I-7-T411H, "Control Bank D Rod Position Indication and Rod Stop C-11 Calibration," Revision 5A

- May 8, 2006: Units 1 and 2, Procedure SP-312, "Security System Emergency Power Source and Load Transferring System," Revision 15B

- May 16, 2006: Unit 2, Procedure STP 15, "Integrated Test of Engineered Safeguards and Diesel Generators," Revision 38A

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

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

a. Inspection Scope

The inspectors performed in-office reviews of Revision 4, Change 5 to Section 4 of the Diablo Canyon, Units 1 and 2, Emergency Plan, and Revision 34 to Emergency Plan Implementing Procedure EP G-1, “Emergency Classification and Emergency Plan Activation,” both submitted in February 2006.

These revisions changed emergency classification level descriptions and revised emergency action levels as described in NRC Bulletin 2005-002, "Emergency Preparedness and Response Actions for Security-Based Events."

These revisions were compared to their previous revisions, to the criteria of NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants,” Revision 1; to Nuclear Energy Institute (NEI) 99-01, “Methodology for Development of Emergency Action Levels,” Revision 2; to NRC Bulletin 2005-02, and to the requirements of 10 CFR 50.47(b) and 50.54(q), to determine if PG&E adequately implemented 10 CFR 50.54(q).

This review was not documented in a Safety Evaluation Report and did not constitute the approval of licensee changes; therefore, these changes are subject to future inspection. The inspectors completed two samples during this inspection.

b. Findings

No findings of significance were identified.

1EP6 Emergency Preparedness Evaluation (71114.06)

a. Inspection Scope

For drills contributing to drill/exercise performance and Emergency Response Organization PIs, 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.

- June 1, 2006: A full drill involving a main steam line break, a steam generator tube rupture, and failed fuel cladding, including the turnover between two emergency response organization crews

- June 9, 2006: A simulator-based drill involving a main steam line break where a PI opportunity for classification of Notice of Unusual Event 28 existed

Documents reviewed by the inspectors included the Diablo Canyon Power Plant Emergency Plan, Revision 4, and Lesson R061S5, "Imminent PTS," Revision 0.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

This area was inspected to assess PG&E's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas, and worker adherence to these controls. The inspectors 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 inspectors interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspectors performed independent radiation dose rate measurements and reviewed the following items:

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

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

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

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

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

- Physical and programmatic controls for highly activated or contaminated materials (nonfuel) 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

- Radiation work permit briefings and worker instructions

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

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

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

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

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

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

The inspectors completed 19 samples.

b. Findings

Introduction: The inspectors identified a noncited violation of 10 CFR 20.1501(a) because PG&E failed to perform a survey to identify the magnitude and extent of radiation levels for radiological hazards. The violation had very low safety significance.

Description: On April 18, 2006, the inspectors toured the 100-foot elevation of the Unit 2 auxiliary building and identified elevated radiation levels near Chemical Volume Control System Valves CVCS-2-8502 and CVCS-2-8512A. Subsequent surveys by PG&E confirmed radiation levels of up to 200 millirem per hour on contact and 28 millirem per hour at 30 centimeters in this area. From a review of a previous survey map, the inspectors noted that the highest general area radiation level in the area was approximately 5 millirem per hour. Unit 2 began a plant evolution (RCS forced oxygenation) that had the potential to raise radiation levels in several areas of the unit. Due to the forced oxygenation process, PG&E implemented their posting guides and restricted personnel access to high radiation areas in Unit 2 that had potentially higher-than-normal radiation levels. However, PG&E did not restrict personnel access to radiation areas or survey a hallway on the 100-foot elevation that had the potential for higher-than-normal radiation levels prior to allowing personnel to enter them. PG&E's posting guides did not address any actions that needed to be implemented for radiation areas or the hallways of the 100-foot elevation. The inspectors determined that PG&E failed to survey the area to determine the magnitude and extent of the radiation levels and to evaluate the radiological hazards prior to allowing personnel to enter the area and whether the posting guides communicated any required action.

Analysis: The failure to survey is a performance deficiency. The finding was greater than minor because it was associated with the Occupational Radiation Safety Cornerstone attribute of Exposure Control and Monitoring and affected the cornerstone objective to ensure the adequate protection of a worker's health and safety from exposure to radiation because workers could have unknowingly received additional radiation exposure from the increase in radiation levels. 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 finding was determined to be of very low safety significance because: (1) it did not involve as low as reasonably achievable (ALARA) planning or work 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 had crosscutting aspects associated with human performance because adequate resources were not established for the survey requirements.

Enforcement: 10 CFR 20.1501(a) requires that each licensee make or cause to be made surveys that may be necessary to comply with the regulations in Part 20 to determine the extent and magnitude of radiation levels and to evaluate the radiological hazards. Pursuant to 10 CFR 20.1003, survey means an evaluation of the radiological conditions and potential hazards incident to the production, use, transfer, release, disposal, or presence of radioactive material or other sources of radiation. Contrary to this requirement, on April 18, 2006, PG&E failed to survey the 100-foot elevation of the Unit 2 auxiliary building to assure compliance with 10 CFR 20.1201, which limits radiation exposure to occupational workers to 5.0 rem total effective dose equivalent. This violation was entered into PG&E's CAP as AR 0665039. Because this finding is of very low safety significance and 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 50-323/06-03-04, Failure to Survey to Identify the Magnitude and Extent of Radiation Levels to Identify Radiological Hazards.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspectors assessed PG&E's performance with respect to maintaining individual and collective radiation exposures ALARA. The inspectors used the requirements in 10 CFR Part 20 and PG&E's procedures required by TS as criteria for determining compliance. The inspectors interviewed PG&E personnel and reviewed:

- Five (to 10) outage or on-line maintenance work activities scheduled during the inspection period and associated work activity exposure estimates which were likely to result in the highest personnel collective exposures

- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements

- Integration of ALARA requirements into work procedure and radiation work permit documents

- Person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements

- Dose rate reduction activities in work planning

- Workers use of the low dose waiting areas

- First-line job supervisors' contribution to ensuring work activities are conducted in a dose efficient manner

- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas

- Self-assessments, audits, and special reports related to the ALARA program since the last inspection

The inspectors completed nine samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 PI Verification (71151)

.1 Cornerstone: Occupational Radiation Safety

- Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors reviewed PG&E's documents from January 1 through March 31, 2006. The review included corrective action documentation that identified occurrences in locked high radiation areas (as defined in PG&E's TS), 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 inspectors interviewed PG&E personnel who were accountable for collecting and evaluating the PI data. In addition, the inspectors toured plant areas to verify that high radiation, locked high radiation, and very high radiation areas were properly controlled. 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.

The inspectors completed one sample in this cornerstone.

b. Findings

No findings of significance were identified.

.2 Cornerstone: Public Radiation Safety

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

a. Inspection Scope

The inspectors reviewed PG&E's documents from January 1 through March 31, 2006. PG&E's records reviewed included corrective action documentation that identified occurrences for liquid or gaseous effluent releases that exceeded PI thresholds and those reported to the NRC. The inspectors interviewed PG&E personnel who 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.

The inspectors completed one sample in this cornerstone.

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 follow-up 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.

- April 26, 2006: High Stator Temperature Trends on Component Cooling Water Motors

Documents reviewed by the inspectors are listed in the attachment.

b. Findings

No findings of significance were identified.

.3 Semiannual Trend Review

a. Inspection Scope

The inspectors completed a semiannual trend review of repetitive or closely-related issues that were documented in ARs, system and component health reports, quality assurance audits, trend reports, Diablo Canyon 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 January 1 to June 30, 2006. When warranted, some of the samples expanded beyond those dates to fully assess the issue. The inspectors also reviewed CAP items associated with troubleshooting. 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 Quality Verification Assessment 060480001, "Troubleshooting," dated April 14, 2006. The purpose of the assessment was to evaluate the implementation of the troubleshooting program as described in Procedure MA1.DC10, "Troubleshooting," Revision 9. Quality Verification identified a need for improvement in documentation of problem statements, data acquisition results, determination of possible failure modes, troubleshooting plans, and analysis of results. In particular, maintenance personnel's implementation of the troubleshooting procedure often did not meet the troubleshooting attributes, while engineering personnel's implementation of troubleshooting had only minor inconsistencies. Furthermore, the assessment observed the need for improvement in the knowledge of troubleshooting requirements throughout the organization for: (1) when troubleshooting should be implemented, (2) what types of equipment problems require troubleshooting, and (3) the level of planning and documentation required for low level equipment problems. Quality verification found that Procedure MA1.DC10 continued to be difficult to use despite revisions to the procedure.

The inspectors also reviewed previous Quality Verification assessments, dating back to 2004, for troubleshooting observations. These assessments are listed in the attachment. While the assessments pointed out that the site has shown improvement in troubleshooting efforts since 2003, the inspectors observed that Quality Verification had previously identified similar issues as those discussed above. The following are some insights from previous assessments, which also covered previous revisions to Procedure MA1.DC10.

- In some instances, initial troubleshooting efforts failed to identify the cause of the problem for safety-related and/or risk-significant equipment.

- On several occasions, the site was reluctant to enter a more rigorous/formal troubleshooting format, since it was seen as time consuming and the technicians felt they knew better on how to approach the problem as opposed to following Procedure MA1.DC10. As a result, there were instances where the cause determination was inaccurate, such as the case with Containment Spray Pump 2-2 control cable ground.

- Procedure MA1.DC10 was deficient, making it difficult for maintenance personnel to comply with its requirements. Subsequently, personnel performing troubleshooting relied upon their knowledge and experience to the exclusion of the requirements in the troubleshooting procedure.

- In some instances, maintenance and engineering personnel were reluctant to characterize work activities as "troubleshooting" when in fact the activities involved the investigation of plant equipment problems. Quality Verification recommended that senior management emphasize the expectations for implementing Procedure MA1.DC10 when the criteria for entering the procedure were met.

- Quality Verification noted that the level of detail in troubleshooting documentation was weak. For example, as-found conditions were not documented, results of a component history search were not documented, and documentation of work performed was not detailed.

The inspectors have observed several troubleshooting activities that have occurred on site and, in general, agree with the assessments identified by Quality Verification. Most recently, the inspectors observed troubleshooting for AFW Discharge Valves FW-1-LCV-107 and FW-1-LCV-108, as described in Section 4OA5 of this report.

The inspectors observed that troubleshooting for Valve FW-1-LCV-107 was performed by maintenance personnel. In reviewing the documentation from that troubleshooting effort, the inspectors could not identify any other possible failure mechanisms that had been considered by Maintenance personnel other than the determined cause. Additionally, the inspectors observed data that would tend to contradict the determined cause of the valve, as described in Section 4OA5. The inspectors also observed troubleshooting for Valve FW-1-LCV-108, which had similar indications as Valve FW-1-LCV-107 when it failed to stroke. The troubleshooting team consisted of both Engineering and Maintenance personnel. The inspectors observed that the Engineering personnel were careful to: (1) preserve evidence by arranging the various investigative activities, (2) consider various potential failure mechanisms before investigative activities began, and (3) consider all data available to them. In summary, the inspectors felt that the observations made during the troubleshooting on Valves FW-1-LCV-107 and FW-1-LCV-108 confirmed the observations documented by Quality Verification in their assessments.

.4 Occupational Radiation Safety

a. Inspection Scope

The inspectors evaluated the effectiveness of PG&E’s problem identification and resolution process with respect to the following inspection areas:

- Access Control to Radiologically Significant Areas (Section 2OS1)
- ALARA Planning and Controls (Section 2OS2)

b. Findings

No findings of significance were identified.

.5 Inservice Inspection

a. Inspection Scope

The inspector reviewed the related condition reports on an inservice inspection issued during the current and past refueling outages and verified that PG&E identified, evaluated, corrected, and trended problems. The inspector evaluated the effectiveness of PG&E’s CAP, including the adequacy of the technical resolutions.

b. Findings

No findings of significance were identified.

4OA3 Event Followup (71153)

.1 Main Turbine Trip Due to Personnel Error

a. Inspection Scope

On June 7, 2006, the inspector reviewed the actions taken prior to, during, and following a main turbine trip on Unit 2, on May 25, 2006. Operations personnel were attempting to parallel the main generator to the grid during the reactor startup, following a refueling outage.

b. Findings

No findings of significance were identified.

.2 (Closed) Licensee Event Report 50-275/1-2005-001-00 Steam Generator Tube Plugging Because of Stress Corrosion Cracking

On November 11, 2005, PG&E determined that analysis of eddy current testing on Steam Generators 1-1 and 1-2 indicated that greater than one percent of the tubes were defective as a result of outside diameter stress corrosion cracking at the hot leg tube support plates and at the hot leg top of tubesheet. This determination occurred at the end of Operating Cycle 13. The inspector verified that PG&E took effective corrective action. All defective tubes were plugged and removed from service in accordance with TS 5.5.9, "Steam Generator (SG) Tube Surveillance Program." The licensing basis accident analysis assumes a tube plugging limit of 15 percent per steam generator. The plugging percentage for each Unit 1 steam generator remains within the current allowable limit of 15 percent. Steam Generator 1-1 has 6.8 percent plugged and Steam Generator 1-2 has 9.3 percent plugged. PG&E maintains a comprehensive program to minimize steam generator tube degradation and plans to replace the steam generators at the end of Operating Cycle 15. This licensee event report 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 the Unit 2 pressurizer utilized Alloy 82/182 material in the nozzle to safe end welds for the surge line, the pressurizer safety lines, the power-operated relief valve lines, and the spray line. Stainless steel was used in all other pressurizer penetration welds. In PG&E's response to the bulletin, they committed to a bare metal visual exam of all the welds that had Alloy 82/182 material.

The inspectors reviewed PG&E's response to NRC Bulletin 2004-01 and observed their inspection activities for the Unit 2 pressurizer. The inspectors verified the qualifications of personnel performing the bare metal exam and independently observed several of the subject pressurizer penetration welds for evidence of boric acid deposits and the capability to perform the bare metal exam. The inspectors reviewed Procedure ISI VT 2-1, "Visual Examination During Section XI System Pressure Test," Revision 0, during the inspection.

The activities required in Temporary Instruction (TI) 2515/160 for Diablo Canyon Power Plant Unit 2 have been completed. Documents reviewed by the inspectors are listed in the attachment. This TI is closed for Unit 2.

b. Findings

No findings of significance were identified.

.2 TI 2515/165 - Operational Readiness of Offsite Power and Impact on Plant Risk

a. Inspection Scope

The objective of TI 2515/165, "Operational Readiness of Offsite Power and Impact on Plant Risk," is to gather information to support the assessment of nuclear power plant operational readiness of offsite power systems and impact on plant risk. During this inspection, the inspectors interviewed PG&E personnel, reviewed applicable procedures, and gathered information for further evaluation by the Office of Nuclear Reactor Regulation.

b. Findings

No findings of significance were identified.

.3 (Closed) Unresolved Item (URI) 05000275/05-05-03: Corrective Actions to Prevent Repetitive Failures of AFW Limitorque Valves

a. Inspection Scope

The inspectors performed additional inspection associated with this URI to determine any performance issues associated with design and maintenance practices regarding Limitorque actuators. The inspectors also evaluated any extent of condition and/or generic impacts.

b. Findings

Introduction: A Green, NRC-identified NCV was identified for the failure to correct a significant condition adverse to quality as required by 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action.” Specifically, PG&E failed to preclude repetition of similar failures with Limitorque Model SMB-000 motor-operated valves in the AFW system. The failure of these motor-operated valves affected the ability of the valves to be operated from the control room and the hot shutdown panel. These valves are required to shut in the event of a faulted steam generator or to prevent overfilling of a steam generator.

Description: The AFW system is an engineered safety feature system that is directly relied upon to prevent core damage and RCS overpressurization in the event of transients, such as a loss of normal feedwater or secondary system pipe rupture. It also provides a means for plant cooldown following any plant transient.

Motor-operated Valves FW-1-LCV-107, FW-1-LCV-108, and FW-1-LCV-109 are discharge isolation valves associated with the turbine-driven AFW pump. On March 15, 2003, Valve FW-2-LCV-109 failed to close during routine surveillance testing. Operators failed to preserve the faulted condition by remotely opening the valve, manually stroking the valve, removing the actuator cover and inspecting the contacts, and burnishing the close torque contacts. Because the failure was not repeated during troubleshooting, PG&E staff determined that it was not a maintenance preventable functional failure. However, PG&E staff identified in AR A0578562 that this was a critical component failure that should be prevented from recurring per Procedure ER1.ID1, “Equipment Reliability Process,” Revision 1.

On August 20, 2004, Valve FW-1-LCV-107 failed to operate after corrective maintenance. PG&E staff identified in AR A0616766 that this failure was a maintenance preventible functional failure and directed staff to implement actions to prevent recurrence. The corrective action identified was to revise Procedure MP E-53.10A, “Preventive Maintenance of Limitorque Operators,” to include steps to burnish the torque switch contacts, since the cause of the valve to stroke was determined to be corrosion.

On November 3, 2005, operators were performing a functional test of Valve FW-1-LCV-107 per Procedure STP V-2U2D, “Exercising S/G No. 2 AFW Supply Valves LCV-107 and LCV-108,” Revision 4, after valve packing had been replaced. Motor-operated 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, the valve was opened and not able to be shut. A second attempt to shut the valve was unsuccessful. Records of the subsequent visual inspection indicated that the contact fingers were coated with debris, but not the contact surfaces. Maintenance records also indicated that the actuator cover was removed and the torque switch contacts were burnished. The valve was declared operable after several successful operations. PG&E staff identified this problem in AR A0650104 and again directed that this problem be prevented from recurring.

On February 2, 2006, a similar failure occurred with Valve FW-1-LCV-108. This valve also had successful operations following maintenance with a subsequent failure. Troubleshooting by PG&E staff determined that the torque limit switch contacts had high resistance. During troubleshooting efforts, the inspectors observed that the contact switch housing cover for the Limitorque Model SMB-000 actuators had been modified to allow them to fit over the contact assembly more easily. The inspectors also observed that, even with the modified cover, the installation and removal of the close-fitting cover rubbed against the wires. PG&E troubleshooting personnel determined that the screws would loosen if the wires leading to the torque switch were moved.

The inspectors verified that the installation of the cover and potential for screw loosening by wire movement could contribute to valves failing to actuate, which had not been previously evaluated by PG&E staff as a possible contributor to the failures of Valve FW-1-LCV-107. PG&E initiated a root cause evaluation into the failure of the Model SMB-000 actuators (Nonconformance Report NCR N0002205) and identified organizational deficiencies in the failure analysis of critical components as the root cause. The root cause determined that PG&E staff failed to account for maintenance practices, latent design issues, or environmental effects other than corrosion to prevent repeat failures of Model SMB-000 actuators.

The inspectors determined that PG&E staff failed to promptly identify and correct a significant condition adverse to quality. Specifically, the inspectors determined that PG&E failed to adequately troubleshoot the failures of Valve FW-1-LCV-107. During the inspection, data such as: (1) the failure of the valves to stroke after one or more successful strokes, (2) the conductance capability of the silver torque switch contacts with corrosion, (3) the orientation of the torque switch contacts, and (4) an already present step in the maintenance procedure to clean the torque switch contacts lead the inspectors to question the troubleshooting conclusion of debris or corrosion on the torque switch contacts. Furthermore, the troubleshooting results from Valve FW-1-LCV-108 reduced the likelihood of debris or corrosion as a possible failure mechanism. The inspectors determined that, with the history of similar failures of these type of valve actuators, along with the significance of the system, PG&E should have initiated a root cause evaluation earlier with the Valve FW-1-LCV-107 failures to prevent recurrence of the problem.

<u>Analysis</u>: The performance deficiency associated with this finding was the failure to promptly identify and correct a significant condition adverse to quality associated with the AFW motor-operated discharge valves. 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 the IMC 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to be of 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 finding had a crosscutting aspect in the area of problem identification and resolution since PG&E staff failed to adequately trend, assess, and troubleshoot previous Limitorque SMB-000 actuator failures.

<u>Enforcement</u>: 10 CFR Part 50, Appendix B, Criterion XVI, states, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition

is determined and corrective action taken to preclude repetition. Contrary to this, from 2003 to 2006, PG&E staff failed to identify and implement adequate corrective actions to prevent recurrence of turbine-driven AFW Limitorque SMB-000 actuator failures. Since failure to identify and prevent recurrence of a significant condition adverse to quality was determined to be of very low safety significance and has been entered into the CAP as Nonconformance Report N0002205, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/06-03-05, Failure to Prevent Recurrence of Limitorque Model SMB-000 Failures.

40A6 Management Meetings

Exit Meeting Summary

On April 6, 2006, the inspectors discussed the inspection results of licensed operator requalification with Mr. David Burns, Operations Training Supervisor. PG&E acknowledged the findings presented. The inspectors asked PG&E if any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On April 10, 2006, the inspectors conducted a telephonic exit meeting to present the inspection results on Emergency Action Level and Emergency Plan Changes to Mr. R. Waltos, Supervisor, Emergency Planning, who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

The inspector presented the results of the inservice inspection effort to Mr. J. Becker, Vice President Diablo Canyon Operations and Station Director, and other members of PG&E management on May 3, 2006. PG&E management acknowledged the inspection findings. During the inspection, the inspector asked if any materials examined should be considered proprietary. Several documents were identified as proprietary information by PG&E. The inspector informed PG&E that copies of those documents would be destroyed after their review.

On May 4, 2006, the inspectors presented the occupational radiation safety inspection results to Mr. J. Becker, Vice President Diablo Canyon Operations and Station Director, and other members of the staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

The resident inspection results were presented on July 12, 2006, to Mr. J. Becker, Vice President Diablo Canyon Operations and Station Director, and other members of PG&E management. PG&E acknowledged the findings presented. The inspectors asked PG&E whether any materials examined during the inspection should be considered proprietary. No proprietary information was reviewed by the inspectors.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

PG&E personnel

J. Becker, Vice President - Diablo Canyon Operations and Station Director
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
K. Peters, Director, Engineering Services
J. Purkis, Director, Maintenance Services
P. Roller, Director, Operations Services
D. Taggart, Manager, Quality Verification
R. Waltos, Supervisor, Emergency Planning

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

50-323/06-03-01	NCV	Failure to Follow Welding Procedures (Section 1R08)
50-275/06-03-02	NCV	Failure to Promptly Identify Voiding in Accumulator Discharge Line (Section 1R15)
50-323/06-03-03	NCV	Inadequate Refueling Procedure for Draining and Depressurizing the Reactor Coolant System (Section 1R20)
50-323/06-03-04	NCV	Failure to Survey to Identify the Magnitude and Extent of Radiation Levels to Identify Radiological Hazards (Section 2OS1)
50-275/06-03-05	NCV	Failure to Prevent Recurrence of Limitorque Model SMB-000 Failures (Section 4OA5.3)

Closed

05000275/2005-05-03	URI	Corrective Actions to Prevent Repetitive Failures of Auxiliary Feedwater Limitorque Valves

50-275/1-2005-001-00	LER	Steam Generator Tube Plugging Because of Stress Corrosion Cracking (Section 4OA3.1)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment (71111.04)

Action Requests

A0606585 A0634661 A0661369

Procedures

Number	Title	Revision
STP M-12A	Vital Station Battery Modified Performance Test	14
OP J-9:I	Placing the 125/250V DC System In Service	4
OP H-10:I	Auxiliary Building Switchgear Ventilation System - Make Available and System Operation	27A
PEP EN-1	Plant Accident Mitigation Diagnostic Aids and Guidelines	15
EOP E-1.2	Post LOCA Cooldown and Depressurization	16
OP AP-26	Loss of Offsite Power	8

Other Documents

Calculation 786, Appendix A, "EDG Fuel Oil Storage," Revision 14

IEEE 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations."

Section 1R06: Flood Protection (71111.06)

Action Requests

A0448720	A0457845	A0497879	A0525555	A0529058	A0571204
A0598359	A0620636	A0630476	A0630513	A0635450	A0651267
A0663041					

Work Orders

R0271922

Section 1R08: Inservice Inspection Activities (71111.08)

PG&E Procedures

Number	Title	Revision
MP-56.10	Piping Fabrication, Installation, Repair or System Alteration	16
MA3.DC1	Weld Planning and Inspection	6
SWS-1	Welding in the Presence of Moisture	2
GWS-ASME	ASME General Welding Standard	8
WI-1	Visual Inspection of Welds	7
ISI MONITOR	Inspection of Nondestructive Examination Activities	1
ISI ADD SUCCESS	Additional and Successive Inspections	1
STP M-SGTI	Steam Generator Tube Inspections	12
TS1.ID3	Steam Generator Management Program	0
ER1.ID2	Boric Acid Corrosion Control Program	1
AD4.ID2	Plant Leakage Evaluation	6
STP R-8C	Containment Walkdown for Evidence of Boric Acid Leakage	8A

WESDYNE Procedures

Number	Title	Revision
WDI-ET-002	Intraspect Eddy Current Inspection of Vessel Head Penetrations J-Weld and Tube OD	7
WDI-ET-003	Intraspect Eddy Current Imaging Procedure for Inspection of Reactor Vessel Head Penetrations	9
WDI-ET-004	Instraspect Eddy Current Analysis Guidelines	10
PDI-ISI-254	Remote In-service Inspection of Reactor Vessel Shell Welds	7
PDI-ISI-254-NZ	Remote In-service Examination of Reactor Vessel Nozzle to Shell Welds	0
PDI-ISI-254-SE	Remote In-service Examination of Reactor Vessel Nozzle to Safe End, Nozzle to Pipe, and Safe End to Pipe Welds	2

Action Requests

A0665682 A0665588 A0665547 A0665543 A0665166

Work Orders

C0196956 C0194616 C0198594

Visual Examination

Steam Generator 1 Feedwater Supply Hanger 2037-7V
Auxiliary Feedwater Pump 2-1 Discharge Header Hanger 414-505R
Auxiliary Feedwater Pump 2-1 Discharge Header Hanger 414-386R
Auxiliary Feedwater Supply Hanger 42-42R

Radiographic Examination

CVCS-2-8388C, FW-2

Magnetic Particle Examination

K16-555-16
K16-557-16

Liquid Penetrant Examination

S6-959-2 SPL WIB-503
S6-959-2 SPL WIB-1009

Calculations

Structural Integrity Associates, Inc. Calculation Package PGE-120Q-301,"ASME Code Section XI Flaw Evaluation of Indication in RHR Piping Weld RB-119-11," Revision 0

Section 1R12: Maintenance Effectiveness (71111.12)

Action Requests

A0556053	A0649534	A0650238	A0651876
A0603817	A0650052	A0650418	A0658073

Documents

Number	Title	Revision
NUMARC 93-01	Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants	2
Reg. Guide 1.160	Monitoring the Effectiveness of Maintenance at Nuclear Power Plants	2

Procedures

Number	Title	Revision
STP V-600	General Containment Isolation Valve Leak Tests	20
STP V-623	Penetration 22 and 23 Containment Isolation Valve Leak Test	11

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

Action Requests

A0500194	A0636681	A0657460	A0660735	A0660739	A0660743
A0660745	A0660759	A0660769	A0662536	A0669224	

Procedures

Number	Title	Revision
AD7.DC6	On-line Maintenance Risk Management	9
MA1.DC11	Risk Assessment	7
OP J-6B:IX	Diesel Generator Extended On-Line Maintenance	0
STP M-75G	4kV Vital Bus G Undervoltage Relay Calibration	28

Work Orders

C0187543	R0253468	R0257749	C0203401

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

Action Requests

A0669566	A0672188

Documents

Number	Title	Revision
Operations Policy C-7	Earthquakes	2
MP E-50.45	Qualitrol Type “900" Rapid Response Pressure Relay Maintenance	4

Work Orders

C0204748

Section 1R15: Operability Evaluations(71111.15)

Action Requests

A0663750	A0663823	A0657428	A0668922	A0668929	A0669468
A0669453	A0669270	A0640357	A0666128	A0666211	A0666438
A0666532	A0666701	A0666717	A0666761	A0667468	A0669872

Drawings

Number	Sheet	Title	Revision
106709	2	Safety Injection System	44
437984		Unit 1 Accumulator Injection Loop No. 3 - Design Review Isometric	11
445889		Injection Line for Loop 3 Accumulator 2-3 - Design Review Isometric	5
437547		Single Line Meter and Relay Diagram 120V Instrument AC System	38

Procedures

Number	Title	Revision
AR PK 19-18	Vital UPS Trouble	3
AR PK 19-19	Vital UPS Failure	1A
MP E-65.1A	Maintenance and Overhaul of Solidstate Controls 20 kVA UPS	25
MP I-2.29-1	Capacitor Capacitance and Leakage Testing	5
OP-J-10:IV	Instrument AC System - Transfer of Vital Panel Power Supply	22
PEP M-98A	Setting final Feedwater Flow Nozzles by “AMAG” Crossflow	15
STP M-78C	Transient Event Evaluation	2
TP TB-0616	Emergency Core Cooling System Cold Leg Check Valve Test of SI-2-8956C	0XPR

Work Orders

R0116149 C0204222

Other Documents

Operations Shift Log, Unit 1, Sunday Dayshift, November 27, 2005

Operations Shift Log, Unit 2, Sunday Dayshift, May 21, 2006

PGE-120Q-301, “Flaw Evaluation of Diablo Canyon Unit 2 Residual Heat Removal System Weld,” dated April 4, 2006

NUREG-0927, “Evaluation of Water Hammer Occurrence in Nuclear Power Plants,” Revision 1

Engineering Drawing Transmittals: 31345, 31346, 31347, and 31348, Revision 0

Technical Manual: DC6013738-1-2, “Operation-Maintenance Instructions for 1∅ 20kVA UPS with Regulating Rectifier,” Revision 1

Email from John Miemi to Rudy Ortega, dated June 16, 2005, RE: 2-pole relays

Section 1R17: Permanent Plant Modifications (71111.17)

Action Requests

A0652663

Documents

Engineering Drawing Transmittal 30931, “Modify the 3/16" X 3/16" Mesh Screen of the RHR Inner Screen,” Revision 0, dated January 3, 2006

DCM S-9A, Revision 4, Pages 32-35, “Containment Recirculation Pump Function”

Vendor Document 663216, “Evaluation of the Potential Hydraulic Performance of the Containment Recirculation Sumps,” Revision 3, dated February 26, 2002

Regulatory Guide 1.82, “Water Sources for Long-term Recirculation Cooling Following a Loss-of-coolant Accident,” Revision 3, November, 2003

Calculations

M-580, “Determination of Post LOCA Flood Levels Inside Containment Buildings for Units 1 and 2,” Revision 4, Dated September 2, 1997

M-227, “Post-LOCA Minimum Containment Sump Level,” Revision 4, Dated February 28, 2006

Drawings

Number	Title	Revision
4004934	Sections and Details Recirculation Sump Screens Area “C” Containment Structure	3
4004935	Recirculation Sump Screens Area “G” Containment Structure	1
4004936	Plans, Sections and Details Recirculation Sump Screens Area “G” Containment Structure	3
438208	Recirculation Sump Screens Area “G” Containment Structure	4
498837	Plans, Sections and Details Recirculation Sump Screens Area “G” Containment Structure	5
498838	Plans, Sections and Details Recirculation Sump Screens Area “G” Containment Structure	5
6001027	Recirculation Sump Screen Mod’s	2
6002061	Elevation 91' -0" Recirculation Sump Screens Containment Structure	2
6016131, Sheet 1	RHR Recirculation Sump Screen Addition Demolition Plan	0
6016131, Sheet 2	RHR Recirculation Sump Screen Addition Plan, Sections & General Notes	1
6016131, Sheet 5	RHR Recirculation Sump Addition Demolition Plan	1
6016131, Sheet 6	RHR Recirculation Sump Screen Addition Plan, Sections & General Notes	1
6016131, Sheet 8	RHR Recirculation Sump Screen Addition Sections & Details	1

Section 1R19: Postmaintenance Testing

Action Requests

A0402074	A0664845	A0666578	A0666599	A0670676
A0616738	A0665900	A0666579	A0667681	

Procedures

Number	Title	Revision
MP E-57.14A	PI and HIPOT Testing	19
MP E-57.15	Maintenance and Calibration of Ammeters, Voltmeters, Frequency Meters and Tachometers	9
MP E-65.1A	Maintenance and Overhaul of Solidstate Controls 20 KVA UPS	29
OP B-8DS1	Core Offloading	35
PEP I-17-FIT-484	ASW Magnetic Flowmeters FE-484 and FE-485 Flow Rate Comparision Test	1
PMT 63.51	52HH13 Auxiliary Transformer 22 Hinge Wire Replacement	0
STP I-4A	Analog Channel Operational Test Nuclear Source Range	29A
STP I-4B	Calibration of Source Range Channels	7
STP I-4B1	Removal of a Source Range Channel from Service	17A
STP I-4B2	Calibration Procedure for Source Range Channel	23A
STP I-4B4	Determ of Source Range Detector Characteristic Curves for Westinghouse Low Noise Preamplifiers	16
STP M-27B	Fuel Transfer System Interlock Verification and Functional Testing	8
STP P-ASW-A	Performance Test of Auxiliary Saltwater Pumps	22
STP P-CCP-A21	Comprehensive Pump Test for Centrifugal Charging Pump 2-1	1

Other Documents

Calculation STA-228, “Safety Injection System - 2R13 CCP 2-1 Evaluation,” Revision 0

Field Correction Transmittal Form 31333, “As built drawing 441595 for Unit 2 4kV cubicle 52-HH-13,” Revision 0

Drawing 441595, “Electrical Wiring Diagram 4 KV Switchgear Bus Section “H” Cell 13,” Revision 12

Work Orders

C0204016	R0221536	R0254405	R0266353
C0204027	R0244739	R0264682	R0269399

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

Action Requests

A0658441	A0659687	A0660724	A0661344	A0662965	A0663482
A0663517	A0664429	A0664703	A0665039	A0665254	A0666110
A0666292	A0666296				

Procedures

Number	Title	Revision
OM7.ID1	Problem Identification and Resolution-Action Requests	22
RCP D-211	Control of Work in Radiologically Significant Areas	2
RCP D-220	Control of Access to High, Locked High, and Very High Radiation Areas	31
RCP D-222	Radiation Protection Lock and Key Control	4
RCP D-230	Radiological Control for Containment Entry	16
RCP D-240	Radiological Posting	16
RCP D-420	Sampling and Measurement of Airborne Radioactivity	18A
RCP D-430	Plant Airborne Radioactivity Surveillance	16
RCP D-440	Criteria for Use and Operation of HEPA Equipped Ventilation Units	1
RCP D-500	Routine and Job Coverage Surveys	21

Radiation Work Permits

06-0010	Routine Operations Activities
06-2019	2R13 Fuel Handling at the Spent Fuel Pool
06-2022	2R13 Movement of Reactor Head and Upper Internals
06-2023	2R13 Fuel Movement and Underwater Work in Containment
06-2026	2R13 Lower Cavity and Transfer Canal Work
06-2040	2R13 Primary Steam Generator Setup and Teardown

06-2060	2R13 Pressurizer Relief Maintenance
06-2064	2R13 Non-Containment Valves & Breaches Less Than 100 mrem Per Entry
06-2071	2R13 Reactor Upflow-UHTR Modifications
06-2073	2R13 Under Reactor Head Volumetric Inspection
06-2084	2R13 Reactor Vessel Flange and Stud Hole Inspection

Section 2OS2: ALARA Planning and Controls (71121.02)

Action Requests

A0666290 A0663205 A0663913 A0663953 A0664432 A0664430 A0659218

Procedures

Number	Title	Revision
RCP D-200	Writing Radiation Work Permits	34
RP1.ID1	Requirements for the ALARA Program	2C
RP1.ID2	Use and Control of Temporary Radiation Shielding	5B
RP1.ID3	Respiratory Protection Program	6
RP1.DC4	Radiological Hot Spot Identification and Control Program	1A

Section 4OA1: Performance Indicator Verification (71151)

Action Requests

A0658441

Procedures

Number	Title	Revision
AWP O-003	NRC Performance Indicators: Occupation Exposure Control Effectiveness	4
XI1.DC1	Collection and Submittal of NRC Performance Indicators	6

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

Action Requests

A0024144	A0169950	A0239973	A0302261	A0593433	A0647639
A0039958	A0174572	A0246479	A0433356	A0617930	A0647640
A0086712	A0196328	A0259649	A0434508	A0617931	A0665174
A0146446	A0198060	A0270757	A0446881	A0623598	A0667224
A0150563	A0235288	A0279415	A0514587	A0626219	A0671308
A0152429	A0238661	A0284544	A0566264	A0635891	A0238665
A0161566	A0239954	A0299519	A0579166	A0638342	A0568834

Documents

Design Control Manual S-23B, Main Auxiliary Building Heating and Ventilating System, Revision 20

Design Control Manual T-20, Environmental Qualification, Revision 8

Equipment Control Guidelines, Section 23.1, Area Temperature Monitoring, Revision 2

Drawing DC663213-22, CCW Motor Outline Drawing, Revision 5

Procedure AR PK01-09, CCW Pumps, Revision 6

Section 4OA3: Event Followup

Action Requests

A0669689

Procedures

OP C-3:II, "Main Unit Turbine - Startup," Revision 31
OP L-3, "Secondary Plant Startup," Revision 32

Section 4OA5: Other

Procedures

ISI VT 2-1, "Visual Examination During Section XI System Pressure Test," Revision 0

LIST OF ACRONYMS

ADAMS	agency document and management system
AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
AR	action request
ASME	American Society of Mechanical Engineers
CAP	corrective action program
CFR	*Code of Federal Regulations*
EPRI	Electric Power Research Institute
FSAR	Final Safety Analysis Report
IMC	Inspection Manual Chapter
NCV	noncited violation
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records System
PG&E	Pacific Gas and Electric Company
PI	performance indicator
RCS	reactor coolant system
RVRLIS	reactor vessel refueling level indication system
SSC	structure, system, and component
TI	temporary instruction
TS	Technical Specifications
URI	unresolved item
VUHP	vessel upper head penetration