UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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August 12, 2004

Gregory M. Rueger, Senior Vice
President, Generation and Chief Nuclear Officer
Pacific Gas and Electric Company
Diablo Canyon Power Plant
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SUBJECT: DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000275/2004003 AND 05000323/2004003

Dear Mr. Rueger:

On June 30, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated 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 8, 2004, with Mr. David H. Oatley and members of your staff.

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

Based on the results of this inspection, one NRC-identified finding and three self-revealing findings of very low safety significance (Green) were identified. 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 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 agency document and management system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

William B. Jones, Chief
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Dockets: 50-275
50-323
Licenses: DPR-80
DPR-82

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Inspection Report 05000275/2004003
and 05000323/2004003
w/attachment: Supplemental Information

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-275, 50-323
Licenses:	DPR-80, DPR-82
Report:	05000275/2004003 05000323/2004003
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, 2004
Inspectors:	D. L. Proulx, Senior Resident Inspector T. W. Jackson, Resident Inspector S. M. Wong, Risk Analyst L. E. Ellershaw, Senior Reactor Inspector, Engineering Branch G. W. Johnston, Senior Licensing Examiner, Operations Branch
Approved By:	W. B. Jones, Chief, Projects Branch E Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000275/2004-003, 05000323/2004-003; 04/01/04 - 06/30/04; Diablo Canyon Power Plant Units 1 and 2; Maintenance Risk Assessment and Emergent Work Control, Refueling Outage.

This report covered a 13-week period of inspection by resident inspectors, a senior reactor inspector and a senior licensing examiner. Three self-revealing and one 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: Initiating Events

- Green. A self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion V was reviewed for failure to provide a procedure appropriate to the circumstances. Specifically, Procedure OP A-2:II "Reactor Vessel – Draining the RCS to the Vessel Flange with Fuel in the Vessel," Revision 28, was not appropriate to the circumstances in that Attachment 9.5 prescribed opening cross-tie valves between the pressurizer and reactor vessel head following reactor vessel drain down to the reactor vessel flange. This resulted in an alignment in which the reactor vessel head was not vented, and caused an inadvertent loss of control of vessel level and an inadvertent increase of two feet in vessel level. In addition to the procedure aligning the system at an inappropriate point in the evolution, operators did not maintain the valve status board and assumed that the reactor vessel was adequately vented. Human performance crosscutting aspects were identified involving adequacy and verification of a procedure development and implementation, and system status awareness. Following the above event, and others described in 1R.14.1, .2, .3, and .4, that included inadvertent losses of control of system status by operations leadership, the operations director initiated an operations stand down with the senior reactor operators and day shift plant operations staff, emphasizing the need to control overall system status.

  This finding was of greater than minor significance because it involved the Initiating Events cornerstone and represented a loss of control of reactor vessel level. This finding was assessed using the Significance Determination Process found in Inspection Manual Chapter 0612, Appendix G, "Shutdown Operations," and determined to be of very low safety significance (Green). Item II.C(5) of the shutdown Significance Determination Process ("Drain down controlled") applies. Although this violation resulted in an inadvertent level change of approximately two feet, the level change resulted in an increase in vessel water level, thus not decreasing the time to boil (Section 1R20.1).

Cornerstone: Mitigating Systems

- Green. A self-revealing (Green) noncited violation of Technical Specification 3.0.4, was reviewed for entry into Mode 3 when the specified condition in the Technical Specification APPLICABILITY section was not met. Specifically, a transition from Mode 4 (Hot Shutdown) to Mode 3 (Hot Standby) was conducted with the Turbine-Driven auxiliary feedwater Pump 1-1 inoperable. Operators closed Valves LCV [level control valves]-106, -107, -108, and -109, the remote-manual isolation valves for auxiliary feedwater Pump 1-1 when entering Mode 5 on May 27, 2004. The valves were not reopened prior to entering Mode 3 on May 30. This condition existed for 21 hours. The valves were immediately opened when the condition was identified. A primary contributor to this issue involved human performance crosscutting aspects related to configuration control and control board awareness. Operators failed to track the status of these valves, and failed to perform an adequate review of system status during mode transition (Mode 4 to Mode 3) and shift turnovers.

  This issue affects the mitigating systems cornerstone and is more than minor because it adversely affects the cornerstone objective of availability and reliability of a risk significant system auxiliary feedwater. Using the Phase 1 Significance Determination Process screening worksheet, the inspectors determined that the issue was of very low safety-significance (Green) because the time of inoperability (21 hours) was less than the 72 hours allowed in Technical Specification 3.7.5. Although auxiliary feedwater Pump 1-1 was inoperable per the Technical Specification, the pump was available for operators to manually initiate auxiliary feedwater if needed during a transient or accident. In addition, both 100 percent capacity motor-driven auxiliary feedwater pumps were also available if needed (Section 1R20.3).

Cornerstone: Barrier Integrity

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI was identified by the NRC for failure to identify and correct a condition adverse to quality. Specifically, Pacific Gas and Electric Company failed to inspect and repair the corroded internals of Valve SI-1-8820 prior to changing operating modes. Safety injection check Valve SI-1-8820, listed in the Final Safety Analysis Report as the inboard containment isolation valve for the common high pressure injection header, was found stuck open during a back flow leak test. Pacific Gas and Electric Company mechanically agitated the valve to close it, but did not verify through testing that the valve would forward flow to meet its safety injection function or determine and correct the cause for the valve failing to close. A problem identification and resolution crosscutting aspect was identified for the failure to identify and correct the cause for the valve remaining open. Pacific Gas and Electric Company subsequently placed the unit into a condition that permitted repair of the valve and completed the back flow and forward testing.

  This issue affects the barrier integrity cornerstone objective to ensure that systems penetrating the containment and are connected to the reactor coolant system have adequate isolation to protect the containment barrier. This issue is more than minor because it could have an actual impact on the ability to isolate a fault outside containment given a single failure. Using the Phase 1 Significance Determination Process screening worksheet the inspectors determined that the issue was of very low safety significance (Green) because the finding did not represent an actual open pathway in the physical containment (Section 1R13.1).

- Green. A self-revealing noncited violation of TS 5.4.1.a was reviewed for failure to implement procedures. Specifically, Pacific Gas and Electric Company failed to implement Procedure OP A-2:IX "Reactor Vessel – Vacuum Refill of the RCS," Revision 3, by exceeding the required pressurizer heatup rate of 100 degrees in any one hour. On May 11, 2004, during drawing of a pressurizer steam bubble, operators allowed a pressurizer heatup rate of 129 degrees in one hour. A human performance crosscutting aspect was identified for the failure to establish adequate configuration controls for the conduct and monitoring of the pressurizer heat up as well as for the initiation of the technical review following the identification that the heat up rate had been exceeded. An engineering evaluation was performed that demonstrated the stresses experienced during the heat up were within allowable limits.

  This issue affects the barrier integrity cornerstone objective to ensure that the pressurizer, part of reactor coolant system barrier, remains intact, and not subject to excessive thermal stresses. This issue is more than minor because it could have had an actual impact on the ability to minimize stresses on the reactor coolant pressure boundary. Using the Phase 1 Significance Determination Process screening worksheet the inspectors determined that the issue was of very low safety-significance (Green) because engineers performed an evaluation of the condition and determined that the pressurizer remained operable because the condition was bounded by a previous analysis. Previous analysis indicated that the pressurizer could withstand a maximum heat up rate of up to 282 degrees F per hour without excessive stresses (Section 1R20.2).

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Diablo Canyon Unit 1 began this inspection period defueled with Refueling Outage 1R12 ongoing. On April 28, 2004, Unit 1 entered Mode 6 (Refueling) when operators began reloading fuel into the reactor vessel. Unit 1 entered Mode 5 (Cold Shutdown) on May 4 when maintenance personnel tensioned the reactor vessel head. Operators began increasing reactor coolant temperature, and Unit 1 entered Mode 4 (Hot Shutdown) on May 16. Operators continued to increase temperature, and Unit 1 entered Mode 3 (Hot Standby) on May 18. Operators subsequently reduced temperature on Unit 1 and re-entered Mode 4 on May 20 to perform repairs on a leaking sample line valve. Once the valve was repaired, operators increased reactor coolant temperature and entered Mode 3 on May 21. On May 26, operators initiated actions to place Unit 1 in Mode 5 to troubleshoot a check valve. Unit 1 entered Mode 4 on May 27 and re-entered Mode 5 on the same day. Upon completion of troubleshooting and repair activities, operators increased reactor coolant temperature and Unit 1 entered Mode 4 on May 30 and Mode 3 on the same day. On June 3, operators commenced a reactor startup, and Unit 1 reached Mode 2 (Startup). Operators continued to increase reactor power, and Unit 1 entered Mode 1 (Power Operations) on June 7. On June 7, the Unit 1 main generator was paralleled to the grid; thus ending Refueling Outage 1R12. Unit 1 reached 100 percent power on June 17 and remained at 100 percent power level for the duration of the inspection period.

Diablo Canyon Unit 2 began this inspection period at 100 percent power. On June 18, operators commenced a power reduction to 52 percent on Unit 2 to perform main condenser and tunnel cleaning. Upon completion of cleaning activities, operators increased reactor power on June 21 and reached 100 percent power on June 22. Unit 2 remained at 100 percent power for the duration of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather (71111.01)

a. Inspection Scope

The inspectors performed one adverse weather protection inspection this quarter. The inspectors performed reviews of the design features, equipment, and plant procedures for protecting mitigating systems from the adverse effects of unseasonal high temperatures. High outdoor temperatures greater than the nominal outside temperature of 78° F could result in temperature conditions inside the plant buildings exceeding the design inside temperature of 104° F that would affect the satisfactory performance of mitigating systems during accident conditions. On April 27, 2004, when the outdoor temperature at the plant exceeded 90° F, the inspectors conducted a walkdown of the Unit 2 125 VDC Battery Rooms, Inverter Rooms, and 480 VAC Switchgear Rooms to evaluate Pacific Gas and Electric Company's (PG&E's) implementation of procedures in response to hot weather conditions. During the walkdown, the inspectors verified that additional ventilation in the affected rooms were established by using portable fans and holding doors open by restraints. Security officers and continuous fire watches were posted at the open doors. The inspectors used the following annunciator procedures:

- Procedure AR PK15-05, “Ambient Air Temp PPC,” Revision 16
- Procedure AR PK15-09, “Electrical Rooms Temp Monitor,” Revision 18
- Procedure AR PK15-10, “ESF Equipment Rooms Temp Monitor,” Revision 9

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

The inspectors performed one partial system walkdown during this inspection period.

Partial System Walkdowns

.1 Unit 1 Steam Generator (SG) 1-1 Bowls

a. Inspection Scope

On April 1, 2004, during nozzle dam installation, PG&E staff discovered that a steel-wire brush had disassembled inside SG 1-1. The bristles to the brush were deposited in the cold and hot leg bowls of SG 1-1. The inspectors verified PG&E’s preparation and actions for removing the bristles from SG 1-1. The inspectors used Procedure MP M-7.62, “Manual Installation/Removal of Steam Generator NES Type WR Primary Nozzle Dams,” Revision 3, as guidance while monitoring removal of the wire brush.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

The inspectors performed 8 fire protection walkdowns and one fire drill review during this inspection period.

.1 Routine Observations

a. Inspection Scope

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

- Units 1 and 2, Diesel Engine Generator Rooms of the Turbine Building
- Units 1 and 2, Switchgear Rooms of the Auxiliary Building
- Units 1 and 2, Intake Structure
- Units 1 and 2, Radiological Control Area of the Auxiliary Building

b. Findings

No findings of significance were identified.

.2 Fire Drill (71111.05A)

a. Inspection Scope

On June 23, 2004, PG&E performed a fire drill that involved a fire in the Unit 2 turbine building rigging loft. The scenario involved an individual who has been incapacitated inside the rigging loft due to smoke, and the presence of a fire inside the rigging loft. The inspectors verified that:

- PG&E fire fighting personnel properly donned protective clothing and self-contained breathing apparatus

- Fire hoses were properly laid out and could reach the fire

- The fire area of concern was entered in a controlled manner

- Adequate equipment was brought to the fire scene

- Appropriate command, control, and communication was implemented

- The fire brigade checked for fire victims and potential fire propagation into other plant areas

- Pre-plan fire fighting strategies were used

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

The inspectors performed 3 samples of inservice inspection activities.

.1 Performance of Nondestructive Examination Activities Other than SG Tube Inspections

a. Inspection Scope

Inspection Procedure 71111.08 specified a review of two or three types of nondestructive examination activities be conducted: Volumetric (radiographic or ultrasonic), surface (magnetic particle or liquid penetrant), and visual (VT-1 to determine the surface condition of a part or component, VT-2 to locate evidence of leakage, and VT-3 to determine the general mechanical and structural condition of parts or components). The inspectors reviewed examples of all three types, as noted in the following table:

System	Component/Weld Identification	Examination Method
Reactor Coolant	Pressurizer, 3-inch Power Relief Valve Line, Welds WIB-446, -447, and -449	Ultrasonic
Feedwater	SG 1-2, 16-inch Feedwater Supply Pipe, Weld WICG-02-2H	Radiography (four views: 0-12, 12-24, 24-38, and 38-0)
Chemical and Volume Control	Valve CVCS-1-86, ASME Code Section XI replacement, Weld FW-3	Visual (VT-1) and Liquid Penetrant
Residual Heat Removal	12-inch Residual Heat Removal Injection Line 985 to Hot Legs 1 and 2, Weld WIC-95	Ultrasonic (four examinations conducted during 1R8, 1R9, 1R10, and 1R12)

The inspectors verified the certifications of the Level II nondestructive examination personnel observed performing examinations or identified during review of completed examination packages.

The inspection procedure also specified review of one or two examinations from a previous outage with recordable indications that were accepted for continued service. The inspectors reviewed one such examination performed during Refueling Outage 1R8 on residual heat removal pipe-to-tee Weld WIC-95, which identified a flaw that was unacceptable to the criteria of Table IWB-3514.2 in Section XI of the American Society of Mechanical Engineers (ASME) Code. Action Request (AR) A0430829 was initiated on April 29, 1997, to address this condition. As allowed by the ASME Code, piping containing a flaw exceeding the allowable flaw standards of IWB-3514.3 may be evaluated to determine its acceptability for continued service in accordance with the evaluation procedures and acceptance criteria of IWB-3641 or IWB-3642. Using the linear elastic fracture mechanics method, PG&E determined the flaw to be acceptable for continued service. Action Request A0431755 was initiated on May 5, 1997, to track subsequent engineering-requested and ASME Code-required re-examinations of this weld. The inspectors reviewed the reports of the subsequent ultrasonic examinations performed on Weld WIC-95 during Refueling Outages 1R9 (February 1999), 1R10 (October 2000), and 1R12 (March 2004). Those reports showed that the flaw has not increased in size.

The inspection procedure further specified that, if PG&E completed welding on the pressure boundary for ASME Code Class 1 or 2 systems since the beginning of the previous outage, then verification should be performed that acceptance and preservice inspections were accomplished in accordance with the ASME Code for one to three welds. The inspectors reviewed the technique sheet, radiographic examination report, and radiographic film for Weld WICG-02-2H on the 16-inch SG 1-2 feedwater supply line. Recordable indications observed by the inspectors on the radiographic film were consistent with the indications identified in the radiographic examination reports.

The inspection procedure specified verification be made that one or two ASME Code Section XI repairs or replacements met ASME Code requirements. The inspectors observed performance of welding, and visual and liquid penetrant preservice inspections on a pipe-to-pipe weld during an ASME Code Section XI replacement of Chemical and Volume Control Valve CVCS-1-86. Additionally, the inspectors verified that controls had been established and were being implemented regarding welding material storage, issuance, and use. This also included a review of the welding procedure specification and supporting procedure qualification records.

Finally, the inspection procedure specified verification that activities are performed in accordance with ASME Code requirements and that indications and defects, if present, were dispositioned in accordance with the ASME Code. The inspectors verified, through direct observation or record review, that ultrasonic, liquid penetrant, radiographic, and visual examinations of the above systems/components were performed in accordance with the ASME Code. The inspectors determined that the correct nondestructive examination procedures were used, that examinations and conditions were as specified in the procedure, and that test instrumentation or equipment was properly calibrated within the allowable calibration period. Defects were not identified by PG&E during the inspector-observed examinations. Indications, however, were revealed by the examinations, compared against the ASME Code specified acceptance standards, and properly dispositioned.

References to the specific nondestructive examination reports associated with the above listed examinations are identified in the attachment to this report.

b. Findings

No findings of significance were identified.

.2 SG Tube Inspection Activities

a. Inspection Scope

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

At the time of the inspection, PG&E had completed in situ pressure testing on nine tubes in SG 1-4. The tested tubes, all containing circumferential primary water stress corrosion cracking (PWSCC) indications in the U-bend area, are identified in the attachment to this report. The inspectors reviewed the Diablo Canyon Unit 1 SG Tubing Degradation Assessment and compared the in situ test screening parameters to the guidelines contained in the EPRI document "In Situ Pressure Test Guidelines," Revision 2. The inspectors reviewed the in situ pressure tests performed on the nine tubes in SG 1-4 and verified that the appropriate criteria (> 1.73 volts) had been used in the screening process. The test results showed that four of the nine tubes exhibited leaks at various pressure plateaus, up to and including 3 times normal operating pressure (4950 psig).

The inspectors reviewed the following four Diablo Canyon examination technique specification sheets used during this refueling outage and the qualifying EPRI examination technique specification sheets to verify that the essential variables regarding flaw sizing accuracy, tubing, equipment, technique, and analysis had been identified and qualified through demonstration:

DCPP Examination Technique Specification Sheet (Acquisition)	EPRI's Examination Technique Specification Sheets
DCPP ETSS # 1 (Bobbin)	96001.1, 96004.1, 96005.2, 96007.1, 96008.1, and 96012.1
DCPP ETSS # 2 (Three Coil Plus-Point, except U-bend)	20510.1, 20511.1, 21409.1. 21410.1, 96703.1, 22401.1, 22842.3,
DCPP ETSS # 3 (Three Coil Plus-Point, U-bend)	96511.2

DCPP ETSS # 4 (Three Coil Plus-Point, U-bend High Frequency)	99997.1

The inspection procedure specified comparing the estimated size and number of tube flaws detected during the current outage against the previous outage operational assessment predictions to assess PG&E's prediction capability. The inspectors reviewed Report "Steam Generator Tubing Degradation Assessment for Diablo Canyon Unit 1 Refueling Outage 1R12 – March 30, 2004," Revision 0. The purposes of the report were to provide (1) a comprehensive review and overall plan for detection and assessment of degradation to be addressed during Refueling Outage 1R12, (2) predictions as to the type and extent of degradation expected to be found, (3) determination of degradation growth rates, (4) documentation of detection and sizing performance indices along with the determination that the examination technique specification sheets were site validated, and (5) in situ pressure testing screening or threshold values that are consistent with EPRI SG guidelines, Diablo Canyon structural limits, and commitments to the NRC. At the time of the inspectors' review, PG&E had completed approximately 65 percent of the scheduled eddy current examinations (ET), the results of which appeared to be on track with the predictions identified in the report.

The inspection procedure specified confirmation be made that the SG tube ET scope and expansion criteria meet TS requirements, EPRI guidelines, and commitments made to the NRC. The inspectors' review determined that the SG tube ET scope and expansion criteria incorporated all requirements, guidelines, and commitments.

The inspection procedure also specified that, if PG&E identified new degradation mechanisms, then verify that PG&E had fully enveloped the problem in an analysis and had taken appropriate corrective actions before plant startup. At the time of this inspection, a new degradation mechanism had been identified in the Unit 1 SGs (circumferential primary water stress corrosion cracks in the U-bends); however, it was not unexpected in that the same phenomena had been identified in the earlier Unit 2 outage. Since it had been previously identified, PG&E had taken actions to assure that this degradation mechanism was analyzed and included in the ET scope of the Unit 1 SGs.

The inspection procedure also required confirmation that all areas of potential degradation were being inspected, especially areas which were known to represent potential ET challenges (e.g., top of tubesheet, tube support plates, and U-bends). The inspectors confirmed that all known areas of potential degradation, including ET-challenged areas, were included in the scope of inspection and were being inspected.

The inspection procedure further required verification that repair processes being used had been approved in the TSs (TS) for use at the site. During this inspection, the inspectors observed the installation of a minimum of 12 mechanically rolled plugs in the cold leg side of SG 1-4. The inspectors verified that this particular plugging operation was an NRC-approved repair process.

The inspection procedure also required confirmation that the TS plugging limit was being adhered to and determination whether depth sizing repair criteria were being applied for indications other than wear or axial PWSCC in dented tube support plate intersections. The inspectors determined that PG&E, in response to Information Notice 2002-21, did account for crack-like indications in dented tube support plate intersections by including these parameters in their ET computer programming and the acquisition and analysis examination technique specification sheets. Further, the ET data analysts had been presented with specific training associated with this type of indication. The inspectors confirmed that the TS plugging limits were being adhered to.

The inspection procedure stated that, if SG leakage greater than 3 gallons per day was identified during operations or during post-shutdown visual inspections of the tubesheet face, then assess whether PG&E had identified a reasonable cause and corrective actions for the leakage based on inspection results. The inspectors did not conduct any assessment because this condition did not exist.

The inspection procedure required confirmation that the ET probes and equipment were qualified for the expected types of tube degradation and assessment of the site-specific qualification of one or more techniques. The inspectors observed portions of ET performed on the following locations in SG 1-3 and 1-4: full length, U-bends, special interest locations, and cold-leg side dent locations. During these examinations, the inspectors verified that (1) the probes appropriate for identifying the expected types of indications were being used, (2) probe position location verification was performed, (3) calibration requirements were adhered to, and (4) probe travel speed was in accordance with procedural requirements. The assessment of site-specific qualifications of the techniques being used, including a listing of the specific techniques and qualifications reviewed, is addressed and identified in the table above.

The inspection procedure specified that, if loose parts or foreign material on the secondary side of the SGs were identified, assess PG&E's corrective actions. One loose part in SG 1-3, originally detected by ET (Plus Point) during the previous refueling outage (1R11), was again detected during the current refueling outage. The loose part is characterized as a metallic object with an approximate size of 0.4 inch by 0.75 inch, and tightly wedged between tubes R1C49 and R1C50 at the hot-leg side top of tubesheet. Multiple attempts during 1R11 to dislodge the object were unsuccessful. The ET signal has not changed and no tube wear was detected. PG&E personnel stated that examinations will be conducted post-chemical cleaning on SG 1-3 (subsequent to this inspection) to detect and remove any potential loose parts. Continued operation during the just-completed Unit 1 Cycle 12 had been determined to be acceptable because no tube wear was detected and the loose part was adhered to the tubesheet. The current ET results validated justification for continued operation.

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

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed selected Inservice Inspection-related ARs issued during the current and past refueling outages. The review served to verify that PG&E's corrective action process was being correctly utilized to identify conditions adverse to quality and that those conditions were being adequately evaluated, corrected, and trended. As part of this effort, the inspectors evaluated the adequacy of root cause determinations and technical resolutions.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On June 22, 2004, the inspectors witnessed one operator requalification exam in the simulator. The scenario involved a loss of a vital 4kV bus, an earthquake, an anticipated transient without scram, and an inadvertent safety injection. The inspectors verified the crew's ability to meet the objectives of the training scenario, and attended the post-scenario critique to verify that crew weaknesses were identified and corrected by PG&E staff.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors performed two inspections of PG&E's Maintenance Rule implementation for equipment performance problems. The inspectors assessed whether the equipment was properly placed into the scope of the rule, whether the failures were properly characterized, and whether goal setting was recommended, if required. Procedure MA1.ID17, “Maintenance Rule Monitoring Program,” Revision 13, was used as guidance. The inspectors reviewed the following ARs:

- A0589785, "Maintenance Rule Performance Criteria, Goal Setting Review," for Units 1 and 2 Auxiliary Feedwater System Level Control Valve controllers

- A0560825, "Maintenance Rule Performance Goal Setting Review," for Units 1 and 2 Component Cooling Water Butterfly Valves

b. Findings

No findings of significance were identified.

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

The inspectors performed two inspection samples of maintenance risk assessments and emergent work control.

.1 Emergent Work

a. Inspection Scope

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

- Unit 1, Auxiliary Saltwater 1-1 discharge piping flange repair (AR A0606612 and Work Order C0188512)

- Unit 1, Valve SI-1-8820 Stuck Open following forward flow

b. Findings

Introduction. A Green noncited violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, was identified by the NRC for failure to identify and correct the cause for check Valve SI-1-8820 not seating following a forward flow test. Safety injection check Valve SI-1-8820, listed in the FSAR Update as the inboard containment isolation valve for the common high pressure injection header, was found stuck open during a back flow leak test. PG&E mechanically agitated the valve to close it, and initiated a prompt operability assessment (POA).

Description. Valve SI-1-8820 was a 3-inch Velan swing check valve located inside containment on the common high pressure injection line. Valve SI-1-8820 was listed in FSAR Table 6.2-29 as a containment isolation valve and was also listed in Procedure AD13.DC1, "Control of the Surveillance Testing Program," Revision 18B; PG&E's procedure for controlling containment isolation valves.

On May 17, 2004, Valve SI-1-8820 failed to seat during performance of Procedure STP V-5D "Charging Injection Check Valves SI-8900A-D and SI-8820 Back Flow Test," Revision 1. PG&E attempted to apply a differential pressure (600 psid) across the valve but was unable to seat the valve. Subsequently, PG&E personnel mechanically agitated the valve to get it to seat. The back leakage test then was completed satisfactorily. PG&E initiated AR A0609710 to evaluate the condition of Valve SI-1-8820.

On May 18 PG&E issued an POA that considered the open and close functions of the valve. The POA considered that since the valve was currently shut and had previously passed its full flow test (prior to being mechanically agitated), the valve was operable because it could meet its containment isolation function early in an accident scenario. PG&E considered that after the injection phase the valve would open and no longer be needed to close. PG&E determined that it was not necessary to postulate a second break, and that if isolation was needed that Valves 8801A/B could be used.

The inspectors questioned PG&E's POA because it did not address the root cause of the valve sticking open and did not discuss the need to determine if the condition was continuing to degrade. In addition, PG&E had not demonstrated the ability of the valve to forward flow following the valve being closed by being mechanically agitated. PG&E had several theories involving the potential valve failure mechanism, none of which could be verified (e.g. oversized disc, bushing binding, angular misalignment, and contact between the disc and body). In addition, PG&E took credit for sequential operation of the valve, in that it would not be needed to close if the charging pumps were continuously injecting. The inspectors determined that without knowing the cause of the valve sticking, PG&E could not adequately demonstrate operability of the valve in either direction. The inspectors also pointed out that successfully testing Valve SI-1-8820 (isolation function) only occurred after preconditioning of the valve to seat, rather than the ASME code requirement that the valve be tested after closure by normal means without additional force or exercising. The inspectors noted that the failure of Valve SI-1-8820 to close was a condition adverse to quality that was not corrected. The NRC staff discussed the need to agitate the valve to provide closure, the lack of a forward flow test following the seating of the valve and the lack of an identified cause for the valve initially failing to seat. A problem identification and resolution crosscutting aspect was identified for the failure to identify and correct the cause of the valve remaining open. PG&E subsequently commenced a plant cooldown from Mode 3 to Mode 5 on May 26 to inspect and repair the valve.

Upon examination, PG&E staff determined that there were corroded valve internals. The valve was repaired and successfully tested in the forward flow direction and in its isolation function. PG&E entered Mode 3 on May 30.

Analysis. This issue affects the barrier integrity cornerstone objective to ensure that systems penetrating the containment and are connected to the reactor coolant system have adequate isolation to protect the containment barrier. This issue is more than minor because it could have an actual impact on the ability to isolate a fault outside containment given a single failure. Using the Phase 1 Significance Determination Process (SDP) screening worksheet the inspectors determined that the issue was of very low safety significance (Green) because the finding did not represent an actual open pathway in the physical containment. In addition, an alternate means existed to isolate the penetration, in that motor operated Valves SI-1-8801A/B were in series with Valve SI-1-8820, and could isolate a fault on the charging injection line

Enforcement. The failure to identify and correct the condition that resulted in check Valve SI-1-8820 sticking open is a violation of 10 CFR 50, Appendix B, Criterion XVI. Because this violation was of very low safety significance and has been entered into the corrective action program as AR A0609710, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/04-03-01, Failure to take corrective actions for stuck open safety injection check valve.

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

a. Inspection Scope

.1 Reactivity Control

The inspectors reviewed an event on June 21, 2004, involving the addition of approximately 122 gallons of boric acid to the Unit 2 volume control tank when operators failed to close Valve CVCS-2-FCV-111B. Unit 2 had been at 52 percent reactor power for main condenser and tunnel cleaning, and operators were in the process of increasing reactor power at 2.5 MW/min when the event occurred. The inadvertent addition of boric acid to the volume control tank caused the reactor power ramp rate to decrease from 2.5 MW/min to 1 MW/min. Operators added 1300 gallons of water to offset the boric acid and return the reactor power ramp to 2.5 MW/min. This event was documented in AR A0612811. The inspectors reviewed operator actions, procedures, and other postevent documents.

.2 Reactor Cavity Fill

The inspectors followed up on an event that occurred on March 27, 2004. Water was inadvertently added to the upper reactor cavity with the intent on filling the lower reactor cavity. Operators marked up sections of Procedure OP B-2:II "RHR – Filling the Refueling Cavity," Revision 31, to perform a fill of the lower cavity. However, operators used the incorrect section of the procedure and inadvertently gravity filled the upper reactor cavity from the refueling water storage tank. This path can result in splashing as the water flows to the lower reactor cavity. Operators used Section 6.15 of the procedure when Section 6.7 was the proper section. This issue was entered into the corrective action program as AR A0603873.

.3 Outage Safety Plan Implementation

On March 23, 2004, Unit 1 operators failed to comply with the outage safety plan. The outage safety plan required level in at least two SGs to be greater than 15 percent in Mode 5 with loops filled, as a backup method of decay heat removal. Because of inadequate knowledge of the outage safety plan, operators allowed all four Unit 1 SG levels to decrease below 15 percent, while performing other evolutions. Pre-shift briefings ("tailboard") did not include a review of outage safety status, the responsibility of the on-shift senior reactor operators. This issue was entered into the corrective action program as AR A0603349.

.4 Spent Fuel Pool Cleanup

On April 4, 2004, operators inadvertently transferred 13,000 gallons of water from the refueling water storage tank to the Unit 1 spent fuel pool. Operators performed two evolutions simultaneously that were not compatible for the plant conditions. The spent fuel pool demineralizer was aligned to filter water from the spent fuel pool while the refueling water purification pump was recirculating water through the spent fuel pool demineralizer from the refueling water storage tank. Refueling water storage tank level dropped 3 percent while spent fuel pool level raised 15-inches. This issue was entered into the corrective action program as AR A0604858.

b. Findings

No findings of significance were identified. A human performance crosscutting aspect was identified for these events involving procedure or outage plan adherence and ensuring operator actions did not impact plant operations in a manner not anticipated.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

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

- Units 1 and 2 Velan valve yokes not assembled as seismically tested (AR A0604776)
- Units 1 and 2 Vital 4kV Bus Control Transfer Relays ("HFA" Relays) (AR A0604224)
- Unit 1 foreign material in SG (AR A0604541)
- Unit 2 lack of solder on Relay K341 diode (AR A0605890)
- Unit 2 Centrifugal Charging Pump 2-1 cracks in outboard bearing cover flange (AR A0612376)
- (Unit 1) Foreign material in Diesel Engine Generators 1-1 and 1-2 (AR A0606981)

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed 4 post-maintenance tests for selected risk-significant systems to verify their operability and functional capability. As part of the inspection process, the inspectors witnessed and/or reviewed the postmaintenance test acceptance criteria and results. The test acceptance criteria were compared to the TS and the FSAR Update. Additionally, the inspectors verified the tests were adequate for the scope of work and were performed as prescribed, jumpers and test equipment were properly removed after testing, and test equipment range, accuracy, and calibration were consistent for the application. The following selected maintenance activities were reviewed by the inspectors:

- Unit 1, Centrifugal Charging Pump Recirculation Valve CVCS-1-8479B, following grinding work on valve exhaust port on March 5 (Work Order C0186650)
- Unit 1, Diesel Engine Generator 1-3 air start solenoid valve replacement and engine inspection on March 28 (Work Orders C0187465 and C0187466)
- Unit 1, Check Valve RCS-1-8028 inspection on April 1 (Work Orders C0182954 and R0232656)
- Unit 1, Charging Injection Header Check Valve SI-1-8820 inspection and parts replacement on May 28 (Work Order C0189419)

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors witnessed and evaluated PG&E's performance during the 12th refueling outage for Unit 1. The outage lasted from March 22 to June 7, 2004. Before and during the outage, the inspectors evaluated PG&E's consideration of risk in developing outage schedules; use of risk reduction methodologies in control of plant configurations; development of mitigation strategies for losses of key safety functions; and adherence to the operating license and TS requirements. Specifically, the inspectors observed PG&E's actions in the following areas:

- Outage risk control plan, prior to and during implementation
- Mode transitions from power operation (Mode 1) to reactor vessel defueled, and then the return to power operation
- Defense-in-depth and handling of unexpected conditions
- Plant configuration control, particularly clearance of equipment
- Supply and control of electrical power with regards to TS requirements and outage risk plans
- Adequacy of decay heat removal for the reactor vessel, refueling cavity, and spent fuel pool
- Fuel assembly movement, tracking, and inspections
- Containment closure and containment closure capability with respect to the TS and outage risk plans
- Adequate control of reduced inventory and mid-loop conditions
- Movement of heavy loads inside containment and the turbine building
- Operator overtime usage

b. Findings

.1 Reactor Vessel Drain Down

Introduction. A self-revealing violation of 10 CFR Part 50, Appendix B, Criterion V was reviewed for failure to provide a procedure appropriate to the circumstances. Specifically, Procedure OP A-2:II "Reactor Vessel – Draining the RCS to the Vessel Flange with Fuel in the Vessel," Revision 28, was revised for Refueling Outage 1R12, and directed opening valves that vented the head (by placing the narrow range level indication system in service) after commencement of drain down, resulting in false level indication. When the reactor vessel head was vented by placing the level indication system in service an inadvertent increase in reactor vessel level occurred.

Description. On March 26, 2004, while draining water from the reactor coolant system, to partially drain the reactor vessel, an inadvertent sudden increase of 2 feet in vessel level occurred. PG&E concluded that this sudden change was caused by draining the vessel head unvented, and subsequently opening the valves after significant drain down. Procedure OP A-2:II "Reactor Vessel – Draining the RCS to the Vessel Flange with Fuel in the Vessel," Revision 26, was revised for Refueling Outage 1R12, and directed opening Valves V2 and RCS-1-8070 that vented the head (the cross-tie valves between the top of the pressurizer and the reactor vessel head) after commencement of drain down. The reactor head was vented by placing the narrow range reactor vessel level indicating system in service per Section 9.5 of Procedure OP A-2:II, in which the line up included the cross-tie valves to vent the reactor vessel head. In previous revisions of this procedure, the narrow range level indication system was placed in service prior to draining to the flange. Revision 26 of Procedure OP A-2:II, moved the step to place the narrow range level indication system in service until after the reactor vessel level was drained to the vessel flange.

In addition, operators were not maintaining the valve status board that showed the lineups of the temporary installed systems such that the senior reactor operators could review system status for the procedure in progress. Operators noted that the valve status board for the level indicating systems showed that Valves V2 and RCS-1-8070 were shut. However, operators assumed that the system was aligned properly (with the cross-tie valves between the pressurizer and reactor vessel head opened), and that the status board was not being updated. A contributing cause of the inadvertent level change was the lack of questioning attitude and failure to maintain system status.

This finding contains a human performance crosscutting aspect as it relates to procedure development and implementation. A second crosscutting aspect was identified for the control of system status that would have been aided by maintaining the status board. Operations personnel failed to perform an adequate technical review of Procedure OP A-2:II prior to Refueling Outage 1R12, thus providing a procedure not appropriate to the circumstances resulting in a self-revealing violation of 10 CFR Part 50, Appendix B, Criterion V. This issue was entered into the corrective action program as AR A0603803.

Following the above event and others described in Sections 1R14.1, .2, .3, and .4 that included inadvertent losses of control of system status by operations leadership, the operations director initiated an operations stand down with the senior reactor operators and day shift plant operations staff. Emphasis was placed on understanding plant conditions and maintaining the "big picture" rather than concentrating on performance of individual procedure steps.

Analysis. This finding was of greater than minor significance because it involved the Initiating Events cornerstone and represented a loss of control of reactor vessel level. This finding was assessed using the SDP found in Inspection Manual Chapter (IMC) 0612, Appendix G, "Shutdown Operations," and determined to be of very low safety significance (Green). Item II.C(5) of the shutdown SDP ("Drain down controlled") applies. Although this violation resulted in an inadvertent level change of approximately two feet, the level change resulted in an increase in vessel water level, thus not decreasing the time to boil.

Enforcement. 10 CFR 50, Appendix B, Criterion V states in part that activities affecting quality shall be prescribed by procedures of a type appropriate to the circumstances. Procedure OP A-2:II partially implemented this requirement. Contrary to this requirement, Procedure OP A-2:II, was not appropriate to the circumstances in that Attachment 9.5 prescribed opening cross-tie valves (V2 and RCS-1-8070) between the pressurizer and reactor vessel head following reactor vessel drain down to the reactor vessel flange. This resulted in an alignment in which the reactor vessel head was not vented, and caused an inadvertent loss of control of vessel level and inadvertent increase of two feet in vessel level, when Attachment 9.5 was performed. Because this violation was of very low safety significance and has been entered into the corrective action program as AR A0603803, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/04-03-02, Inadequate procedure for reactor vessel draining resulted in inadvertent two feet level change.

.2 Exceeding Pressurizer Heat Up Rate.

Introduction. A self-revealing Green NCV of TS 5.4.1.a was reviewed for failure to implement procedures. Procedure OP A-2:IX, "Reactor Vessel – Vacuum Refill of the RCS [Reactor Coolant System]," Revision 3, by exceeding the required pressurizer heat up rate of 100 degrees in any one hour. Following identification of the excessive heat up rate, operators also did not implement licensee controlled specification Equipment Control Guideline 7.5, which required an engineering evaluation be performed within 6 hours to determine the affect of the excessive heatup rate on the pressurizer and verify that the pressurizer will remain operable.

Description. On May 11, 2004, operators were drawing a pressurizer steam bubble in accordance with Procedure OP A-2:IX, Section 6.42. During this evolution, pressurizer level dropped so operators began charging into the reactor coolant system to recover pressurizer level. This charging of cold water caused the pressurizer to cool down. Thus operators, energized all pressurizer heaters for a maximum heat up. These two evolutions made control of pressurizer parameters challenging. In addition, operators were monitoring an out of service pressurizer pressure channel, while drawing the bubble. Pressure Transmitters PT-403 and -405 were cleared, but no out of service tags had been hung on the transmitters. Thus, pressurizer pressure parameters appeared to be stable when using the out of service instruments. The inadequate control of plant evolutions and parameters resulted in an excessive heat up rate.

Procedure OP A-2:IX, Section 6.42.3, required the pressurizer heat up rate to be less than 100 degrees in any one hour. To ensure that a 100 degree change in pressurizer temperature in any one hour was not exceeded, Procedure OP A-2:IX, Section 5.15, limited the instantaneous heatup rate be less than 100 degrees/hour as well. On May 11, during establishment of a pressurizer steam bubble, operators recorded temperatures at 8:30 am of 187.7 degrees F and at 9:30 am a pressurizer temperature of 317.2 degrees F; a one hour change of 129.5 degrees F. In addition, at 9 am, operators recorded an equivalent instantaneous heat up rate of 212.2 degrees F/hour. Exceeding a pressurizer heatup rate of 100 degrees F in any one hour was a violation of Procedure OP A-2:IX and TS 5.4.1.a. This issue was entered into the corrective action program as AR A0609107.

After noting that Unit 1 pressurizer experienced a heat up rate of 129 degrees in one hour, operators entered Equipment Control Guideline 7.5-A.2 and -A.3 (a licensee controlled specification), which requires that an engineering evaluation be performed within 6 hours of the exceeding the 100 degrees F in any one hour heat up rate to determine the affect on the pressurizer and verify continued operability of the pressurizer. Operators did not meet the action times of A.2 and A.3 that required engineering evaluations within 6 hours. A human performance crosscutting aspect was identified with the failure to establish adequate configuration controls for the conduct and monitoring of the pressurizer heat up and for the initiation of the technical review following the identification that the heat up rate had been exceeded.

Subsequently, engineering personnel performed this evaluation and determined that the pressurizer remained operable because the condition was bounded by a previous analysis. Previous analysis indicated that the pressurizer could withstand a maximum heat up rate of up to 282 degrees F per hour without excessive stresses.

Analysis. This issue affects the barrier integrity cornerstone objective to ensure that the pressurizer, part of reactor coolant system barrier, remains intact, and not subject to excessive thermal stresses. This issue is more than minor because it could have an actual impact on the ability to minimize stresses on the reactor coolant pressure boundary. Using the Phase 1 SDP the inspectors determined that the issue was of very low safety-significance (Green) because engineers performed an evaluation of the condition and determined that the pressurizer remained operable because the condition was bounded by a previous analysis. Previous analysis indicated that the pressurizer could withstand a maximum heat up rate of up to 282 degrees F per hour without excessive stresses.

Enforcement. TS 5.4.1.a states, in part that procedures shall be implemented covering the procedures in Regulatory Guide 1.33, Appendix A, 1978. Regulatory Guide 1.33, Appendix A, 1978, Section 3.a lists a procedure for filling the reactor coolant system. Procedure OP A-2:IX partially implements this requirement and states, in Section 5.15 to maintain pressurizer heatup rate less than 100 degrees in any one hour. Contrary to this requirement, on May 11, 2004, operators allowed a 129.5 degree change in pressurizer temperature in one hour. Because this violation was of very low safety significance and has been entered into the corrective action program as AR A0609107, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/04-03-03, Exceeding pressurizer heat up rate.

.3 Auxiliary Feedwater Pump (AFW) Operability

Introduction. A self-revealing (Green) NCV of TS 3.0.4, was reviewed for entry into Mode 3 when the specified condition in the APPLICABILITY section was not met. Specifically, a transition from Mode 4 (Hot Shutdown) to Mode 3 (Hot Standby) was conducted with the Turbine-Driven AFW Pump 1-1 inoperable. The APPLICABILITY Section in TS 3.7.5, Auxiliary Feedwater (AFW) System, requires that 3 AFW pumps be operable in Mode 3. Operators closed Valves LCV-106, -107, -108, and -109, the remote-manual isolation valves for AFW Pump 1-1 when entering Mode 5 on May 27, 2004, to prevent gravity fill of the SGs from the condensate storage tank. However, the valves were not reopened prior to entering Mode 3 on May 30. This condition existed for 21 hours.

Description. Valves LCV-106, -107, -108, and -109 are the remote-manual isolation valves for AFW Pump 1-1. These valves are motor operated valves with control switches and position indication in the control room. These valves are open during Modes 1 through 3 for AFW operability and do not receive an automatic open signal. On May 26, 2004, PG&E initiated a cooldown of Unit 1 (Mode 3 to Mode 5) using Procedure OP L-5 "Plant Cooldown from Minimum Load to Cold Shutdown," Revision 70, to inspect and repair Valve SI-1-8820. Section 8.3.13 of Procedure OP L-5 required manual isolation of the AFW leads, with the applicable valves tagged for information. In previous, plant cooldowns, operators shut the local manual handwheel valves to meet this procedure step, controlling the status of the valves with a clearance.

The remote-manual (motor operated) isolation valves for all four Unit 1 AFW injection lines were shut during the mode transition. Operators shut Valves LCV-106, -107,-108, -109 to prevent gravity fill of the SGs when the plant entered Mode 5. Operators assumed that the procedure for mode transition or plant heatup Procedure OP L-1, "Plant Heatup from Cold Shutdown to Hot Standby," Revision 68, directed operators to reopen these valves. Thus the operators did not use any administrative means to control system status. Procedure OP L-0, "Mode Transition Checklists," Revision 56 contained a statement to verify AFW operability, and referenced the need to ensure that the locked valve checklist was completed. No reference was made to position of and did not specifically direct operators to ensure that the motor operated discharge Valves (LCV-106, -107, -108, and -109) were open. Thus, when Unit 1 entered Mode 3 at 4:58 pm on May 30, AFW Pump 1-1 was inoperable. Operators did not identify the valves out of position during board walkdowns or shift turnovers until 21 hours later, on May 31 at 2:13 pm. This issue was entered into the corrective action program as AR A0611033.

The inspectors identified a human performance crosscutting aspect for this finding that involved inadequate configuration control of equipment needed to support plant operation. In addition a separate crosscutting aspect was identified for the adequacy of operator walkdowns of the main control boards that failed to identify the level control valves were not properly positioned until 21 hours after the plant was placed in Mode 3, a condition where all three AFW trains shall be operable.

Analysis. This issue affects the mitigating systems cornerstone and is more than minor because it adversely affects the cornerstone objective of availability and reliability of risks significant systems. Using the Phase 1 SDP the inspectors determined that the issue was of very low safety-significance (Green) because the finding occurred over a period of time (21 hours) that was less than the 72 hours allowed in TS 3.7.5. Although AFW Pump 1-1 was inoperable per the TS, the pump was available for operators to manually initiate AFW if needed during a transient or accident. In addition, both 100 percent capacity motor-driven AFW pumps were also available if needed.

Enforcement. TS 3.0.4 states, in part, that when a limiting condition for operation is not met, entry into an applicable operational mode shall not be made. TS 3.7.5 states that three AFW trains shall be operable in Modes 1, 2, and 3. Contrary to this requirement, on May 30, 2004, Unit 1 of Diablo Canyon entered Mode 3 with only two trains of AFW operable. Specifically, AFW Pump 1-1 was inoperable because the remote-manual (motor operated) isolation valves for all four Unit 1 AFW injection lines were shut during the mode transition. Because this violation was of very low safety significance and has been entered into the corrective action program as AR A0611033, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-275/04-03-04, Violation of TS 3.0.4 for changing modes with an AFW pump inoperable.

1R22 Surveillance Testing (71111.22)

b. Inspection Scope

The inspectors evaluated six routine surveillance tests to determine if PG&E complied with the applicable TS requirements to demonstrate that equipment was capable of performing its intended safety functions and operational readiness. The inspectors performed a technical review of the procedure, witnessed portions of the surveillance test, and reviewed the completed test data. The inspectors also considered whether proper test equipment was utilized, preconditioning occurred, test acceptance criteria agreed with the equipment design basis, and equipment was returned to normal alignment following the test. The following tests were evaluated during the inspection period:

- Procedure STP M-9D1, “Diesel Generator Full Load Rejection Test,” Revision 11, on March 27 for Unit 1
- Procedure STP V-630, “Penetration 30 Containment Isolation Valve Leak Testing,” Revision 22, on March 23 for Unit 1
- Procedure STP V-635, “Penetration 35 Containment Isolation Valve Leak Testing,” Revision 24, on March 26 for Unit 1
- Procedure STP M-9G, “Diesel Generator 24-Hour Load Test and Hot Restart Test,” Revision 35 on April 1 for Unit 1
- Procedure STP M-15, “Integrated Test of Engineered Safeguards and Diesel Generators,” Revision 37B on May 5 for Unit 1
- Procedure STP V-5D, "Charging Injection Check Valves SI-8900A-D and SI-8820 Back Flow Test," Revision 1, on May 17

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Emergency Preparedness Evaluation (71114.06)

a. Inspection Scope

On June 22, 2004, the inspectors witnessed an operator requalification exam in the simulator that included emergency preparedness performance indicator opportunities for emergency classification and notification. The scenario simulated an earthquake, damage to the refueling water storage tank, and a loss of coolant accident. During the scenario, conditions arose that required operators to declare an Alert due to the earthquake and a Site Area Emergency due to the loss of coolant accident. The inspectors attended and verified PG&E's self-critique of the scenario.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Reactor Safety Performance Indicator Verification

a. Inspection Scope

The inspectors verified eight samples of performance indicators. The inspectors reviewed these indicators for the period from the second quarter of 2003 through the first quarter of 2004 to assess the accuracy and completeness of the indicator. The inspectors reviewed plant operating logs and PG&E monthly operating reports to support this inspection. The inspectors used NEI 99-02, "Regulatory Assessment Performance Indicator Verification," Revision 2, as guidance for this inspection.

- Units 1 and 2 High Pressure Safety Injection Availability
- Units 1 and 2 Residual Heat Removal Availability
- Units 1 and 2 Diesel Engine Generator Availability
- Units 1 and 2 AFW Availability

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Valve CCW-1-459 Liner Damage

a. Inspection Scope

The inspectors reviewed PG&E response to AR A0604751, which discussed liner damage to Valve CCW-1-459. The inspectors reviewed Procedure OP AP-11, "Malfunction of Component Cooling Water System," Revision 21, the Bases for TS 3.7.7, and Section 9.2.2 of the FSAR – Update to support this inspection. The inspectors also reviewed the following ARs :

- A0430777, "CCW-1-459 Leaking By"
- A0541103, "CCW-1-459 Leaks By"

b. Findings

No findings of significance were identified.

.2 Semi-Annual Review

a. Inspection Scope

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

- System and Component Health Reports
- Quality Assurance Audits Reports
- Trend Reports
- Self Assessments
- Diablo Canyon Internal Performance Indicators
- NRC Inspection Reports
- NRC End-of-Cycle Assessment

b. Findings

No findings of significance were identified.

In the 2003 mid-cycle assessment letter, the NRC determined that there was a substantive cross-cutting issue in the area of human performance for the Diablo Canyon Power Plant. Human performance events during the 2003 Unit 2 refueling outage (2R11) were a major contributor to the substantive crosscutting issue. During the 2004 Unit 1 refueling outage (1R12), the inspectors noted both a decrease in the number and significance of human performance events. Positive improvements included contractor oversight and more supervisor involvement in refueling outage work. However, the inspectors noted human performance challenges in operator alignment of systems, and foreign material control. While the majority of these events were minor, PG&E has recognized the challenges in these areas and is currently developing corrective actions to improve human performance.

In the 2003 end-of-cycle assessment letter, the NRC determined that there was a substantive crosscutting issue in the area of problem identification and resolution. The inspectors have been monitoring performance in the areas of identifying, evaluating, and correcting problems at the Diablo Canyon Power Plant. The inspectors have noted the higher number and quality of prompt operability determinations since last year. The inspectors have also noted a decrease in the number of repeat equipment problems due to poor troubleshooting. Several systems, including the diesel engine generators and Vital 125 VDC system, have received heightened attention due to past performance issues. The inspectors will continue to monitor PG&E's performance in the area of problem identification and resolution.

Other notable trends include the critical equipment clock resets, engineering workload, and event trend reports. The 12-month, rolling average, critical equipment clock resets decreased from 20 in January 2004 to 9 in April. The Quality Performance Assessment Report – 1st Quarter 2004 identified the engineering workload as very high. And lastly, the 4Q 2003 Processes, Procedures, and Programs Quarterly Trending Report identified a higher number of event trend reports being generated due to recent efforts to capture equipment failure and condition data for all equipment problems. PG&E management was aware of those adverse trends mentioned above and is currently implementing corrective actions to improve performance.

.3 Cross-Reference to Problem Identification and Resolution Findings Documented Elsewhere, Section 1R13.1 documents a problem identification and resolution crosscutting aspect for the failure to identify and correct the cause of a safety injection check valve sticking open.

4OA3 Event Followup (71153)

.1 (Closed) Licensee Event Report (LER) 05000275/2002002-00, Steam Generator Tube Plugging Due to Stress Corrosion Cracking

On May 19, 2002, with Unit 1 in Mode 6 (Refueling), analysis of eddy current testing on SG 1-2 indicated that greater than one percent of tubes were defective. The inspectors verified that PG&E complied with TS 5.5.9 and 5.6.10 and documented the deficiency in AR A0556015. The inspectors also verified that PG&E took appropriate corrective actions and no new findings were identified during the review. This LER is closed.

.2 (Closed) LER 05000275/2002005-00, TS 3.4.10 Not Met During Pressurizer Safety Valve Surveillance Testing Due to Random Lift Setting Spread

On June 10, 2002, PG&E identified that two of the three Unit 2 pressurizer safety valves had lift setpoints outside the Technical Specification 3.4.10 tolerance. During routine surveillance testing at an offsite facility, the two out-of-tolerance pressurizer safety valves had lift setpoints that were 1.9 percent low and 2.6 percent high, while the Technical Specification 3.4.10 tolerance was +/- 1 percent. PG&E adjusted the setpoints of the deficient pressurizer safety valves within tolerance, retested them, and returned them to service.

The inspectors reviewed this issue and determined that PG&E fully complied with the Technical Specification requirements from the time of discovery of the condition. No other reasonable opportunity existed to identify this condition other than removal and offsite testing during a refueling outage. Therefore, the inspectors determined that no violation of NRC requirements occurred. The inspectors reviewed PG&E corrective actions and determined that the actions were reasonable. PG&E documented the problem in AR A0559624. This LER is closed.

.3 (Closed) LER 05000275/2002006-00, Technical Specification LCO 3.7.17.2 Not Met During the 1R11 Refueling Outage When Two Fuel Assemblies Were Placed in Adjacent Locations

On May 6, 2002, during Refueling Outage 1R11, fuel Assembly J55 was placed adjacent to fuel Assembly DD14, resulting in a violation of TS 3.7.17. Technical Specification 3.7.17 requires that the combination of initial enrichment, fuel pellet diameter, and burn-up of each spent fuel assembly stored in Region 2 of the spent fuel pool shall be within the acceptable area of Figure 3.717-2, or the fuel assembly is stored in a checker board pattern with water cells or cells containing nonfissile material. Fuel Assembly DD14 was required to be in a checker board pattern. PG&E determined that a personnel error by engineers that prepared, reviewed, and approved the core offload sequence allowed the two fuel assemblies to be adjacent to each other. For corrective actions, PG&E revised procedures for the core offload sequence and began using a new fuel-tracking software program to plan fuel assembly movements.

The inspectors reviewed the corrective actions and determined that the actions were reasonable. This finding constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. PG&E documented the problem in Nonconformance Report N0002151. No new findings were identified in the inspector's review. This LER is closed.

.4 (Closed) LER 05000323/2002003-01, Technical Specification 3.7.7 Not Met Due to Cable Fault

On August 19, 2002, operators received ground alarms on component cooling water (CCW) Pump 2-3. Upon investigation, PG&E determined that there was a ground fault in the "C" phase power cable. PG&E requested enforcement discretion regarding TS 3.7.7, Action A.1, which required the pump to be returned to operable status in 72 hours. The NRC granted verbal enforcement discretion until August 25. On August 24, CCW Pump 2-3 was returned to operable status. PG&E determined that the root cause of the cable failure was a manufacturing defect. The inspectors reviewed the corrective actions and determined that the actions were appropriate. The inspectors noted that a violation of TS 3.7.7 had occurred, however, enforcement discretion was granted due to the lower risk of repairing the CCW pump while at nominal full power versus shutting down the reactor to perform the repairs. No new findings were identified by the inspectors, and PG&E documented the cable failure in Nonconformance Report N0002150. This LER is closed.

.5 (Closed) LER 05000323/2002003-00, Technical Specification 3.7.7 Not Met Due to Cable Fault

This LER is an earlier revision of LER 05000323/2002003-01 which is addressed above. This revision of the LER was limited to the preliminary results of the offsite vendor analysis of the failed cable. LER 05000323/2002003-01 provided the final root cause analysis. The inspectors identified no new issues with regards to this LER, and it is closed.

4OA4 Crosscutting Aspects of Findings

Sections 1R14.1, .2, .3. and .4 represent four events that had human performance crosscutting aspects related to procedural adherence. Using the guidance in Manual Chapter 0612, Power Reactor Inspection Reports, the performance issues associated with these events were determined to be minor.

Section 1R20.1 represents an event that resulted from human performance crosscutting aspect involving the revision and implementation of procedures, and awareness of system status.

Section 1R20.2 identified a human performance crosscutting aspect for the failure to establish adequate configuration controls for the conduct and monitoring of the pressurizer heat up rate and for the initiation of the technical review following the identification that the heat up rate had been exceeded.

Section 1R20.3 identified a human performance crosscutting aspect for this finding that involved inadequate configuration control of equipment AFW needed to support plant operation. In addition a separate crosscutting aspect was identified for the adequacy of operator walkdowns of the main control boards.

4OA5 Other

.1 Temporary Instruction (TI) 2515/152, "Reactor Pressure Vessel (RPV) Lower Head Penetration Nozzles (NRC Bulletin 2003-02)," Revision 1

Background

The NRC noted in Regulatory Information Summary 2003-13, "NRC Review of Responses to Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," that most licensees do not perform inspections of Alloy 600/82/182 materials beyond those required by Section XI of the ASME Code to identify potentially cracked and leaking components. For the RPV lower head, the ASME Code specifies that a visual examination be performed during system pressure testing. Licensees may meet the ASME Code requirement by performing an inspection of the RPV lower head without removing insulation from around the head and its penetrations. By performing the visual inspection in this manner, licensees may not be able to detect the amounts of through-wall leakage that would be expected from flaws due to PWSCC or other potential cracking mechanisms.

Diablo Canyon Power Plant performed a bare metal visual (BMV) examination of the RPV lower head penetrations on March 25-26, 2004. The BMV examination was implemented to verify the absence of boric acid crystals, which may be evidence of a leak in the lower head penetration nozzles.

a. Inspection Scope

From March 22 to May 9, 2004, the inspectors conducted an evaluation and assessment of the Unit 1 RPV lower head penetration BMV examination performed by PG&E staff according to TI 2515/152. During the inspection, the inspectors performed the following actions:

- A review of PG&E's response to NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," to ensure compliance with existing regulations;

- A review of qualifications and certification of inspection personnel, as well as, the quality of techniques and equipment to identify small boric acid deposits;

- A verification that PG&E staff were appropriately following their procedural guidance during the examination;

- An independent review of a sample of lower head penetrations to verify the absence of boric acid deposits that may be indicative of primary stress corrosion cracking around the penetrations;

- A review of how PG&E staff dispositions evidence of boric acid on the RPV lower head;

- A verification of PG&E's ability and performance of a 100 percent visual inspection of the penetrations;

- A review of PG&E's corrective actions with regards to anomalies, deficiencies, and discrepancies associated with reactor coolant system structures or the examination process; and

- Identification of areas on the RPV lower head or lower head penetration nozzles obscured by debris, insulation, dirt, boric acid deposits from pre-existing leaks such as from the reactor cavity seal, coatings, or other obstructions.

The inspectors observed 100 percent of the lower head penetration nozzles using videotapes of the RPV lower head examination. In addition, the inspectors observed several examinations of the lower head penetration nozzles while PG&E staff were in the process of examining the RPV lower head. While the examination was in process, the inspectors visited the area of the RPV lower head to observe its general condition and the movement of insulation to accommodate the examination.

b. Findings

No findings of significance were identified.

The inspectors confirmed that PG&E staff inspected 360 degrees of 100 percent of the RPV lower head penetration nozzles. In addition, PG&E performed a thorough inspection of the general condition of the lower head. PG&E staff concluded that none of the RPV lower head penetration nozzles indicated leakage per the BMV examination. The inspectors reviewed staff training, equipment capability, procedures, and the process by which the inspection was performed and found them to be adequate in detecting small boron deposits that would indicate RPV lower head penetration nozzle leakage. The inspectors have provided the following details of the inspection as required by TI 2515/152.

PG&E Response to NRC Bulletin 2003-02

PG&E provided a response to NRC Bulletin 2003-02 in PG&E Letter DCL-03-151. In the response, PG&E noted that prior to the bulletin, they were in compliance with 10 CFR 50.55a, Codes and Standards, which incorporates by reference Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," of the ASME Boiler and Pressure Vessel Code. In particular, PG&E performed visual examinations to verify the absence of boric acid deposits on the RPV lower head without removing the insulation. In February 2003, PG&E performed a BMV inspection of the Unit 2 RPV lower head in response to NRC Bulletin 2002-02. The inspectors verified that PG&E was in compliance with existing regulations for performing RPV lower head inspections.

BMV Examination of Unit 1 RPV Lower Head

PG&E utilized two teams of VT-2 examiners so that the examination could be performed in an expedited manner. One of the examiners drove the robotic crawler, while the other two examiners confirmed locations, indications, and provided technical support at the lower head. During the inspection, the examiners videotaped the examination and logged the locations that were being inspected. To ensure that 360 degrees of the penetration nozzles was being inspected, the examiners noted which quadrant of the nozzle was being viewed. The inspectors viewed the videotapes, traced through the logs, and confirmed that the PG&E examiners had inspected 360 degrees of 100 percent of the RPV lower head nozzle penetrations.

PG&E utilized a robotic crawler that magnetically attached to the bottom of the RPV. A camera was attached to the crawler that had the capability to adjust lighting, focus, and articulate the view angle up and down. The mirror insulation on the bottom of the Unit 1 RPV conformed to the head. PG&E utilized a series of 6 jack screws to lower the insulation approximately 4.5 inches. The robotic crawler was controlled from a remote location via a cable. By controlling the crawler from a remote, shielded location, the examiners were able to keep their radiation dose as low as reasonably achievable. The crawler was able to view all quadrants of all the penetration nozzles. The camera on the crawler was able to show, with clarity, letters that were as small as 0.02 inches in height (i.e., Jaeger J-1 images). The inspectors observed the examination while it was in progress and verified that small boric acid deposits that would indicate RPV lower head penetration nozzle leakage would be detectable by the camera.

The inspectors reviewed the qualification and certification of the personnel performing the examination. Qualifications for a VT-2 examiner were described in Procedure TQ1.ID12, “Qualification and Certification of NDE Personnel,” Revision 2. The inspectors found the procedure requirements to be consistent with industry standards. In addition to training and qualification, each of the examiners had previous experience with BMV examinations for both the RPV top head and lower head. The examination experience was gained at the Diablo Canyon Power Plant and other Westinghouse pressurized water reactors (PWRs). The inspectors reviewed training material for the examiners, which included photos of the RPV lower head penetration nozzle leakage at the South Texas Project Unit 1 and EPRI Technical Report 1007842, “Visual Examination for Leakage of PWR Reactor Head Penetrations.” The inspectors observed the examiners identification and disposition of visual data and found their disposition to be appropriate.

Procedure ISI X-CRDM, “Reactor Vessel Top and Bottom Head Visual Inspections,” Revision 3, governed the BMV examination of the RPV lower head penetration nozzles. The inspectors verified that (1) criteria for the disposition of boric acid indications was appropriate, (2) conduct of the examination was sufficient and according to the procedure, and (3) the procedural guidance satisfied commitments in PG&E’s response to NRC Bulletin 2003-02.

<u>Condition of the Unit 1 RPV Lower Head</u>

The inspectors noted that the Unit 1 RPV lower head did not have indications of boric acid leakage from any of the penetrations. This conclusion was based on a review of the videotaped examination and direct observation at the examination site. The inspectors did note boric acid stains which ran down the RPV and down some of the lower head penetration nozzles. The boric acid stains were readily discernable from boric acid deposits that would indicate nozzle leakage. Boric acid deposits indicating nozzle leakage would have a three-dimensional structure; however, the stains were light film streaks with no structure. The boric acid stains were determined to have originated from slight refueling cavity seal leakage in prior years. PG&E performed inspections at the hot and cold leg penetrations to verify that the boric acid stains did not originate from leakage elsewhere on the RPV. The boric acid stains, in some cases, supported very light surface rust, but there was no indication of metal loss. PG&E determined the boric acid stains would not impact the integrity of the RPV lower head, and therefore, no cleaning is planned. The inspectors verified that the boric acid stains would not mask any potential boric acid accumulation that would indicate RPV lower head penetration nozzle leakage. Additionally, inspectors noted other areas of very light surface rust where the heat-resistant aluminum paint had peeled off the head. No metal loss was identified at these rust locations.

The inspectors noted that all of the penetration nozzles had a ring of heat-resistant aluminum paint on the nozzle, where the base of the nozzle met the lower head. The ring of paint was easily discernable during the inspection process and did not interfere with the examination.

Material Deficiencies That Required Repair

None.

Impediments to Effective Examinations

The inspectors concluded that PG&E examiners encountered no impediments, such as debris, boric acid deposits, insulation, or other obstacles that impacted the effective examination of the RPV lower head. The examiners performed 100 percent of the inspection using the robotic crawler.

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

Background

The RPV heads of PWRs have penetrations for control rod drive mechanisms and instrumentation systems. Nickel-based alloys (e.g., Alloy 600) are used in the penetration nozzles and weld materials. Primary coolant water and the operating conditions of PWR plants can cause cracking of these nickel-based alloys through a process called PWSCC. The susceptibility of RPV head penetrations to PWSCC appears to be linked to the operating time and temperature of the RPV head. In early 2001, circumferential cracking of the vessel head penetration nozzles at the Oconee Nuclear Station was identified. Circumferential cracking is a safety concern because of the possibility of a nozzle ejection if the condition is not detected and repaired. In early 2002, axial cracking of a vessel head penetration nozzle was discovered at the Davis Besse Nuclear Power Station. The axial crack resulted in primary water leakage, which in turn created a cavity in the RPV head.

The operating experience with respect to PWSCC of RPV head penetration nozzles has reinforced the need for more effective inspections. Section XI of the ASME Boiler and Pressure Vessel Code, which is incorporated into NRC regulations by 10 CFR 50.55a, “Codes and Standards,” currently specifies that inspections of the RPV head need only include a visual check for leakage on the insulated surface or surrounding area. These inspections may not detect small amounts of leakage from an RPV head penetration with circumferential or axial cracks. NRC Order EA-03-009 was issued in February 11, 2003 to establish required inspections of RPV heads and associated penetration nozzles at PWRs. These requirements are necessary to provide reasonable assurance that plant operations did not pose an undue risk to the public health and safety. The requirements of that Order were expected to remain in effect pending long-term resolution of RPV head penetration inspection requirements, which is expected to involve changes to the NRC regulations, specifically 10 CFR 50.55a.

BMV examinations of the Diablo Canyon Power Plant, Units 1 and 2 RPVs, had been performed in the prior refueling outages for each unit. No indication of leakage was detected in those examinations, and the results of the NRC inspections for those examinations are covered in the following inspection reports:

- Unit 1, 2002 BMV examination during Refueling Outage 1R11, Inspection Report 50-275; 323/02-03

- Unit 2, 2003 BMV examination during Refueling Outage 2R11,Iinspection Report 50-275; 323/03-05

In response to NRC Order EA-03-009, PG&E performed a BMV examination of the Diablo Canyon Power Plant Unit 1 RPV head and penetration nozzles on March 29-30, 2004. The following paragraphs describe the inspection scope and findings related to the examination.

a. Inspection Scope

From March 22 to May 9, 2004, the inspectors conducted an evaluation and assessment of the Unit 1 RPV head and vessel head penetration BMV examination performed by PG&E staff. During the inspection, the inspectors performed the following actions.

- A review of the susceptibility ranking for Unit 1, including the effective degradation years calculation.

- Independently observe (via videotape if available and if direct observation of the head is not possible) the RPV head BMV examination.

- Independent review and report on the condition of the RPV and a report on PG&E’s capability to detect small amounts of boron.

- A report on areas of the RPV head or vessel head penetration nozzles obscured by boron deposits from preexisting leaks, debris, insulation, or other obstructions.

- A report on anomalies, deficiencies, and discrepancies identified with the associated structures or the examination process when such problems are judged to be significant enough to potentially impede the examination process.

- A review of the scope of PG&E's plan to examine the pressure-retaining components above the RPV head to ensure that all possible sources of boric acid leakage are included, that examination would be effective in identifying boric acid leakage in this area, and that appropriate actions are implemented should boron deposits be identified on the RPV head or related insulation.

- A review of the results of PG&E's examination to ensure that appropriate actions have been taken in response to identified boron deposits on the RPV head or related insulation.

The inspectors observed 100 percent of the RPV head and vessel head penetration nozzles using videotapes of the examination. In addition, the inspectors observed several examinations of the vessel penetration nozzles while PG&E staff were in the process of examining the RPV head. While the examination was in process, the inspectors visited the area of the RPV head to observe its general condition and the movement of insulation to accommodate the examination.

b. Findings

No findings of significance were identified.

General

PG&E performed a BMV examination of the Unit 1 reactor vessel head on March 29-30, 2004, and they did not identify any evidence of primary water leakage from cracks in the RPV head and vessel head penetration nozzles. The inspectors reviewed 100 percent of the RPV head and vessel head penetration nozzles and verified the absence of boric acid deposits that could indicate PWSCC on the RPV head.

Susceptibility Ranking

The inspectors reviewed the bases for the type of examinations performed by PG&E. PG&E determined that the effective degradation years for the Unit 1 reactor vessel head was 10.25 years, as described in Calculation N-289, "Calculate Effective Degradation Years for Reactor Heads to Determine Examination Requirements," Revision 0. The inspectors reviewed the calculation, verified that the appropriate plant-specific information was used as input to the calculation, and confirmed that the effective degradation years was correct. The basis for the reactor vessel head temperature profile came from Table 5-2 of WCAP 14919, "Probabilistic Evaluation of Reactor Vessel Closure Head Penetration Integrity for the Diablo Canyon Units 1 and 2." As a result of the calculated effective degradation years, and absence of previous PWSCC, Unit 1 was a moderate susceptible reactor. NRC Order EA-03-009 requires that moderate susceptible plants perform at least a BMV examination, ultrasonic test, eddy current test, or dye penetrant test every outage. At least once over the course of every two refueling outages, moderate susceptible plants are to perform a BMV examination and a nonvisual exam such as ultrasonic, eddy current, or dye penetrant tests. The inspectors determined that the BMV examination of the Unit 1 reactor vessel head met the inspection requirements of NRC Order EA-03-009.

BMV Examination

The inspectors concluded that PG&E performed a 100 percent BMV examination of the reactor vessel head and vessel head penetration nozzles. The inspectors observed that personnel training, examination equipment, and procedures were adequate to detect small boron deposits that could arise from circumferential or axial PWSSC of the vessel head penetration nozzles.

Following removal of the RPV head, PG&E examiners initiated a BMV examination of the RPV head. The examiners used a robotic crawler with a front- and rear-mounted camera to perform the examination. The cameras had the capability to adjust lighting, focus, and articulate the view angle up and down. The crawler was remotely controlled from a lead-shielded tent adjacent to the RPV head. The lead-shielded tent allowed the examiners to maintain their radiation dose as low as reasonably achievable. As described below, some of the examination had to be performed using video probes due to the inability to get the crawler around the installed RPV head insulation. The use of video probes was limited to approximately 2 percent of the vessel head penetration nozzles. The crawler and video probe cameras were able to show, with clarity, letters that were as small as 0.02 inches in height (i.e., Jaeger J-1 images). PG&E used two teams of examiners, with each team consisting of two examiners. One examiner drove the crawler, while the other examiner assisted in verification of nozzle location and assessment of any boron deposits. The BMV examination was videotaped, and the inspectors used the videotape, as well as direct observation, to verify the absence of boric acid deposits that would be indicative of PWSCC. The inspectors observed that the equipment was properly used during the examination to identify potential small boron deposits.

The inspectors reviewed the training and qualification of the personnel performing the BMV examination. Persons performing the inspection held a VT-2 Level 2 or Level 3 qualification. The qualification process was described in Procedure TQ1.ID12, "Qualification and Certification of NDE Personnel," Revision 2. The inspectors found the procedure requirements to be consistent with industry standards. Persons performing the BMV examination had not only performed the two previous BMV examinations for

Units 1 and 2, but they had also assisted in the BMV examinations at other Westinghouse PWR plants. Examiners received additional training in BMV examinations by EPRI Technical Report 1007842, “Visual Examination for Leakage of PWR Reactor Head Penetrations.” The inspectors observed the examiners identification and disposition of visual data and found their disposition to be appropriate.

The inspectors verified the adequacy of Procedure ISI X-CRDM, “Reactor Vessel Top and Bottom Head Visual Inspections,” Revision 3. The inspectors verified that the procedure provided adequate guidance and examination criteria. Specifically, the procedure provided guidance for complete reactor vessel head examination, including a documentation and tracking mechanism to ensure all vessel head penetrations are examined. The procedure also provided clear standards and acceptance criteria for which the examiners had training and experience. The inspectors observed that the procedure contained guidance for dispositioning boric acid deposits and reporting of anomalies. During the examination, the inspectors noted that personnel were following the procedural guidance and tracking progress according to the procedure.

Condition of the Reactor Vessel Head

As stated above, the inspectors noted the absence of boric acid leakage from the vessel head penetrations. Additionally, the inspectors also noted that there were no boric acid deposits on the head or insulation as a result of leakage from above the reactor vessel head. Procedure ISI X-CRDM provided guidance to PG&E staff for examining the control rod drive mechanisms and canopy seal welds. The inspectors did note slight amounts of debris that were left on top of the reactor vessel head from previous machining and repairs to the insulation or structures above the vessel head surface. This debris did not interfere with the examination since the crawler was equipped with an air hose to blow the debris away from the vessel head penetrations. The inspectors noted that the vessel head was originally painted with a heat resistant aluminum paint. The inspectors also identified a ring of paint at the base of the vessel head penetration nozzles, as well as paint chips in the annulus between the vessel head and the nozzles. The inspectors noted that the paint ring and paint chips did not interfere with the inspection process. The inspectors noted that some of the aluminum paint had chipped off in places on the reactor vessel head, leaving light surface rust. These areas of surface rust did not reveal any metal loss.

Material Deficiencies Identified That Required Repair

None.

Impediments to Effective Examinations

The inspectors concluded that PG&E examiners encountered no impediments, such as debris, boric acid deposits, insulation, or other obstacles that impacted the effective examination of the RPV lower head. The examiners performed 100 percent of the inspection using the robotic crawler and video probe.

.3 TI 2515/154, Spent Fuel Material Control and Accounting at Nuclear Power Plants

a. Inspection Scope

TI 2515/154, Spent Fuel Material Control and Accounting at Nuclear Power Plants, Phases I and II, were completed during this inspection period. Appropriate documentation was provided to NRC management as required.

b. Findings

No findings of significance were identified. Based on the inspection, no immediate accountability issues were identified. In accordance with TI 2515/154 reporting requirements, the inspectors provided the required data to the headquarters staff for further analysis.

.4 TI 2515/156, Offsite Power System Operational Readiness

a. Inspection Scope

The inspectors collected data from licensee maintenance records, event reports, corrective action documents and procedures and through interviews of station engineering, maintenance, and operations staff, as required by TI 2515/156. The data was gathered to assess the operational readiness of the offsite power systems in accordance with NRC requirements such as Appendix A to 10 CFR Part 50, General Design Criterion 17; Criterion XVI of Appendix B to10 CFR Part 50, Plant Technical Specification for offsite power systems; 10 CFR 50.63; 10 CFR 50.65(a)(4), and licensee procedures. Documents reviewed for this TI are listed in the attachment.

b. Findings

No findings of significance were identified. Based on the inspection, no immediate operability issues were identified. In accordance with TI 2515/156 reporting requirements, the inspectors provided the required data to the headquarters staff for further analysis.

40A6 Management Meetings

Exit Meeting Summary

The resident inspection results were presented on July 8, 2004, to Mr. David Oatley, Vice President and General Manager, Diablo Canyon Power Plant, and other members of PG&E management. PG&E acknowledged the findings presented. Discussion of region-based and other inspection results are described in the following paragraphs.

The Inservice Inspection Activities results were presented to Mr. David Oatley, Vice President and General Manager, Diablo Canyon Power Plant, and other members of PG&E management on April 15, 2004. PG&E management acknowledged the inspection results.

The TI 2515/150 and TI 2515/152 inspection results were presented to Mr. Larry Womack, Vice President, Nuclear Services, and other members of PG&E management on May 13, 2004. PG&E management acknowledged the findings presented.

The inspectors asked PG&E whether any materials examined during the inspections should be considered proprietary. Proprietary information was reviewed by the inspectors and left with PG&E at the end of the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

PG&E personnel

J. Becker, Vice President, Diablo Canyon Operations and Station Director
C. Belmont, Director, Nuclear Quality, Analysis, and Licensing
S. Chesnut, Director, Engineering Services
J. Hays, Director, Maintenance Services
S. Ketelsen, Manager, Regulatory Services
M. Lemke, Manager, Emergency Preparedness
D. Oatley, Vice President and General Manager, Diablo Canyon
P. Roller, Director, Operations Services
J. Tompkins, Director, Site Services
L. Womack, Vice President Nuclear Services

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

50-275/2004-03-01	NCV	Failure to take corrective actions for stuck open safety injection check valve (Section 1R13.1)
50-275/2004-03-02	NCV	Inadequate procedure for reactor vessel draining resulted in inadvertent two feet level change (Section 1R20.1)
50-275/2004-03-03	NCV	Exceeding pressurizer heat up rate (Section 1R20.2)
50-275/2004-04-04	NCV	Violation of Technical Specification 3.0.4 for changing modes with an AFW pump inoperable (Section 1R20.3)

Closed

50-275/2002-002-00	LER	Steam Generator Tube Plugging Due to Stress Corrosion Cracking (Section 4OA3.1)
50-275/2002-005-00	LER	Technical Specification 3.4.10 Not Met During Pressurizer Safety Valve Surveillance Testing Due to Random Lift Setting Spread (Section 4OA3.2)
50-275/2002-006-00	LER	Technical Specification LCO 3.7.17.2 Not Met During the 1R11 Refueling Outage When Two Fuel Assemblies Were Placed in Adjacent Locations (Section 4OA3.3)
50-323/2002-003-01	LER	Technical Specification 3.7.7 Not Met Due to Cable Fault (Section 4OA3.4)

50-323/2002-003-00	LER	Technical Specification 3.7.7 Not Met Due to Cable Fault (Section 4OA3.5)

LIST OF DOCUMENTS REVIEWED

<u>Section 1R05: Fire Protection</u>

<u>Standard Operating Guidelines</u>

F-2, “2 IN / 2 OUT,” Revision 1
F-4, “Personal Accountability System,” Revision 1
F-9, “Fire Command,” Revision 1

<u>Section 1R08: Inservice Inspection Activities</u>

<u>Procedures</u>

NDE-PDI-UT-2, “Ultrasonic Examination of Austenitic Piping,” Revision 3
NDE-PT-1, “Solvent Removable Visible Dye Liquid Penetrant Examination Procedure,” Revision
CF5.DC2, “Welding Filler Material Control,” Revision 7
WI-1, Attachment D, “Final Visual Acceptance Criteria,” Revision 7
STP M-SGT1, “Steam Generator Tube Inspection,.” Revision 8
NDE ET-7, “Eddy Current Examination of Steam Generator Tubing,” Revision 4
NDE ET-8, “Site Specific Performance Demonstration for Eddy Current Examination of Steam Generator Tubing,” Revision1

<u>Drawings</u>

1.4-39, Revision 2
049319, sht 108A, Revision 1

<u>Nondestructive Examination Reports</u>

Liquid Penetrant Examination Report
04-026 of Weld FW-3 dated March 30, 2004
Ultrasonic Exmination Data Sheets
N-UT-1B of WIC-95 dated April 18, 1997
N-UT-1B of WIC-95 dated April 29, 1997
N-UT-1B of WIC-95 dated May 2, 1997
N-UT-7 (sizing) of WIC-95 dated May 19, 1997
N-UT-7 (sizing) of WIC-95 dated February 4, 1999
N-UT-1B of WIC-95 dated October 5, 2000
N-UT-7 (sizing) of WIC-95 dated October 6, 2000
NDE-PDI-UT-2 of WIC-95 dated March 18, 2004
NDE-PDI-UT-3 (sizing) of WIC-95 dated March 18, 2004
NDE-PDI-UT-2 of welds WIB-446, -447, and -449 dated March 31, 2004

Radiography Reports

N-RT-1A (RT Technique Sheet) for Weld WICG-02-2H dated May 13, 2002
N-RT-1B of Weld WICG-02-2H dated May 13, 2002

Visual Examination Acceptance

MA3.DC1, Attachment 5.2, “Final Visual Inspection” dated March 30, 2004

Action Requests

A0430829, A0431755, A0416589, A0593453, A0547893, A0604608, A0604652

Work Order Packages

C0185380, C0177679, C0173394

Calculations

MP06065, “Evaluation of Crack Indication per ISI Inspection Documented in AR A-0430829", dated May 24, 1997

Welding Procedure Specifications and Procedure Qualification Reports

WPS 11, “Welding of P8 Materials with GTAW and/or SMAW,” Revision 8, PQRs 201, 235, 499
GWS-ASME, “ASME General Welding Standard,” Revision 7

Engineering Documents

Engineering Information Record EIR 51-1264530-09, “Diablo Canyon EPRI Appendix H Eddy Current Site Validation,” dated April 1, 2004

Steam Generator Tubing Degradation Assessment for Diabl Canyon Unit 1, Refueling Outage 1R12, dated March 30, 2004

Steam Generator Eddy Current Inspection Activities Assessment for 2R11, Quality Verification Assessment 030500012, dated May 15, 2003

Special Process Audit, Audit Report #022670041, dated October 28, 2003

Report CSS 86-5039942-00, “DCPP Unit 1 Voltage-Based ARC Benchmarking and Revised EOC 12 Projections,” dated February 23, 2004

In Situ Tested Steam Generator Tubes (SG 1-4)

R5C67	R6C17	R6C38
R5C69	R6C18	R6C65
R5C70	R6C24	R6C79

Section 1R11: Licensed Operator Requalification

Procedures

EOP E-0, “Reactor Trip or Safety Injection, Revision 27
EOP FR-S.1, “Response to Nuclear Power Generation/ATWS, Revision 14
OP AP-27, “Loss of Vital 4kV and/or 480V Bus, Revision 1

Section 1R19: Postmaintenance Testing

Action Requests

A0603846
A0603875

Procedures

STP M-9A, “Diesel Engine Generator Routine Surveillance Test,” Revision 66
STP M-9L, “Diesel Generator Shutdown Lockout Relay Test,” Revision 24
STP M-9S, “Diesel Generator Operability Verification for “Starting on One Starting Train,” Revision 6A
STP M-21-A.1, “Outage and Pre-Outage Diesel Engine Analysis (Every Refueling Outage),” Revision 1
STP M-21-RTS.1, “Return Diesel Engine to Service Following Outage Maintenance,” Revision 4
STP V-4B, “Functional Test of ECCS Check Valves, RHR-8730A/B, RHR-8742A/B and SI-8820, During Cold Shutdown Conditions,” Revision 12
STP V-5D, “Charging Injection Check Valves SI-8900A-D and SI-8820 Back Flow Test,” Revision 2
STP V-671, “Penetration 71 Containment Isolation Valve Leak Testing,” Revision 17

Other

Clearance 76569

Section 1R22: Surveillance Testing

Action Requests

A0603407
A0603552

Section 1EP6: Emergency Preparedness Evaluation

Procedures

CP M-4, “Earthquake,” Revision 19
EOP E-1, “Loss of Reactor or Secondary Coolant,” Revision 19
EOP E-1.3, “Transfer to Cold Leg Recirculation,” Revision 20
EOP ECA-1.1, “Loss of Emergency Coolant Recirculation,” Revision 1

LIST OF ACRONYMS

ADAMS	Agency Document and Management System
AFW	auxiliary feedwater
AR	action request
ASME	American Society of Mechanical Engineers
BMV	bare metal visual
CCW	component cooling water
CFR	Code of Federal Regulations
EPRI	Electric Power Research Institute
ET	eddy current examinations
FSAR	Final Safety Analysis Report
IMC	Inspection Manual Chapter
LER	Licensee Event Report
NCV	noncited violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records
PG&E	Pacific Gas and Electric Company
POA	prompt operability assessment
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
RPV	reactor pressure vessel
SDP	Significance Determination Process
SG	steam generator
TI	temporary instruction
TS	Technical Specifications