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

April 28, 2003

Gregory M. Rueger, Senior Vice
President, Generation and
Chief Nuclear Officer
Pacific Gas and Electric Company
Diablo Canyon Power Plant
P.O. Box 3
Avila Beach, California 93424

SUBJECT: DIABLO CANYON POWER PLANT - NRC INTEGRATED INSPECTION REPORT 50-275/03-05; 50-323/03-05

Dear Mr. Rueger:

On March 29, 2003, the NRC completed an inspection at your Diablo Canyon Power Plant, Units 1 and 2, facility. The enclosed integrated report documents the inspection findings that were discussed on April 4, 2003, 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.

This report documents five NRC-identified or self-revealing findings which were of very low safety significance (Green). Three of the findings were determined to involve violations of NRC requirements. However, because of their very low risk significance and because they are entered into your corrective action program, the NRC is treating these three findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, three licensee-identified violations which were determined to be of very low safety significance are listed in Section 4OA7 of this report. 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 Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region IV; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Diablo Canyon Power Plant.

Pacific Gas and Electric Company operated under voluntary bankruptcy proceedings during this inspection period. The NRC has monitored plant operations, maintenance, and planning to better understand the impact of the financial situation and how it relates to your responsibility to safely operate the Diablo Canyon reactors. NRC inspections, to date, have confirmed that you are operating these reactors safely and that public health and safety is assured.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

Enclosure:
Inspection Report 50-275, 323/03-05

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-275 50-323
Licenses:	DPR-80 DPR-82
Report:	50-275/03-05 50-323/03-05
Licensee:	Pacific Gas and Electric Company
Facility:	Diablo Canyon Power Plant, Units 1 and 2
Location:	7 ½ miles NW of Avila Beach Avila Beach, California
Dates:	December 29, 2002, through March 29, 2003
Inspectors:	D. L. Proulx, Senior Resident Inspector T. W. Jackson, Resident Inspector R. W. Deese, Resident Inspector, Grand Gulf Nuclear Station M. A. Sitek, Resident Inspector, San Onofre Nuclear Generating Station J. B. Nicholas, Ph.D., Senior Health Physicist D. R. Carter, Health Physics Inspector W. D. McNeill, Senior Reactor Inspector G. W. Johnston, Senior Operations Engineer G. A. Pick, Senior Security Inspector
Approved By:	W. B. Jones, Chief, Project Branch E Division of Reactor Projects
ATTACHMENT:	Supplemental Information

SUMMARY OF FINDINGS

IR 05000275/2003-005, 05000323/2003-005; 12/29/02 - 03/29/03; Diablo Canyon Power Plant Units 1 & 2; Maint Risk Assmnt, Refueling Outage, Access Control to Rad Sig Areas, Identification & Resolution of Problems

This report covered a 13-week period of inspection by resident inspectors and announced inspections by a senior health physics inspector, health physics inspector, senior physical security inspector, and senior reactor inspector. Three Green noncited violations and two Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using IMC 0609 "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The 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 Event

- Green. The inspectors identified a noncited violation of Technical Specification 5.4.1.a for implementation of procedures for operation of offsite power source access. Procedure AD8.DC51 was not followed in that a bucket truck was operated next to Startup Transformer 2-2 that could have directly or indirectly affected the single source of offsite power without approval of the shift foreman and a detailed schedule review having been performed by the outage organization.

  The finding was more than minor since a significant outage work activity was not approved by the shift foreman during Unit 2 midloop operation, a period when industry experience has demonstrated the potential for significant events to occur. NRC Manual Chapter 0609, Appendix G, Shutdown Operations - Significance Determination Process," dated February 27, 2001, was utilized to assess the overall safety significance. Table 1 for Reactor Coolant System Open and Refueling Cavity Level< 23', Section III.A , Power Availability Guidelines-Procedures/Training/Administrative Controls, considers that work activities do not have significant potential to affect existing operable power supplies and that there is control over switchyard and transformer yard activities. The finding is of very low risk significance since a safety assessment was performed prior to the outage work activity beginning and the shift foreman subsequently approved the work to continue without revision to the work safety assessment or the work plan (Section 1R13).

- Green. A self-revealing finding was identified for failing to consider the impact of filling the pressurizer relief tank during midloop operations, which resulted in an indicated decrease in reactor vessel level.

  The finding was more than minor because it affects an attribute and objective of the Initiating Events Cornerstone in that configuration control of shutdown equipment lineup was inadequate. The inspectors found that the procedural requirements were met in that no initiation of transient conditions were induced while at midloop operation. However, the finding was more than minor because an initiating event cornerstone attribute, involving shutdown instrumentation alignment, was potentially affected. Specifically, two reactor vessel level instrument indications, used to support shutdown cooling in midloop operation, indicated that a prompt decrease in reactor coolant inventory had occurred. NRC Manual Chapter 0609, Appendix G, “Shutdown Operations - Significance Determination Process,” dated February 27, 2001, was utilized to assess the overall safety significance. Table 1 for Reactor Coolant System Open and Refueling Cavity Level < 23', Section II.B , Inventory Control Guidelines-Procedures/Training, considers that training procedures and administrative controls are implemented to avoid operations that could lead to perturbations in reactor coolant system level control or decay heat removal flow. The issue was determined to involve change in indication only and therefore was assessed as having very low safety significance (Section 1R20.2).

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding involving ineffective corrective action in placement of ventilation louvers on 12 kV grounding transformer fuse boxes. The placement of the louvers introduced a new failure mechanism, which resulted in a recurrence of a previous event. On August 4, 2001, Units 1 and 2 experienced a loss of startup power as a result of multiple electrical faults in the Startup Transformer 1-1 grounding transformer fuse box. Nonconformance Report N0002130, “Loss of Unit 1 and 2 Startup Power,” documented that the primary cause of the electrical faults was condensation inside the fuse box. The ventilation louvers contributed to the event by allowing outside (salty) air to be drawn into the fuse box. The ventilation louver was installed as a corrective action after the November 22, 1996, Auxiliary Transformer 1-1 grounding transformer fuse box event.

  The SDP Phase 3 analysis was performed by the Office of Nuclear Reactor Regulation Probabilistic Safety Assessment Branch. The analysis indicated that the estimated change in core damage probability for internal and external events probabilities was approximately 6E-7, and the change in large early release probability was approximately 6E-8. The conclusion of the analysis characterized the performance deficiency as an issue of very low safety significance (Section 40A5).

- Green. A self-revealing, noncited violation of 10 CFR Part 50, Appendix B, Criterion XI, was identified for failure to verify by testing the ability of Component Cooling Water Valve CCW-2-18 to meet its design basis function of isolating a postulated leak between trains of component cooling water. This valve was credited for ensuring that a single passive failure of the component cooling water system, that resulted in a 200 gallon-per-minute leak, could be isolated within 20 minutes. However, for several years, the valve had a damaged liner that precluded any effective isolation capability that had not been identified because the licensee had not established a leak testing program for the valve.

The failure to provide adequate testing to ensure that Valve CCW-2-18 could meet its design basis function affected the Mitigating Systems Cornerstone and is more than minor because it had an actual impact on safety. Specifically, the lack of a test program allowed the existence of the damaged valve liner for a significant period of time. A Phase 3 significance determination process assessment was performed for a similar condition that occurred on Unit 1 (NRC Integrated Inspection Report 50-275/00-16; 50-323/00-16, Section 1R14.2). The Phase 3 assessment considered that a passive failure of one train of component cooling water (a low energy system) would have to occur prior to calling upon a comparable valve (to Valve CCW-2-18) to perform its isolation function, a very low probability failure. The assessment also considered that a safety-related 250 gpm makeup source was available to replenish the component cooling water system. Two other nonsafety-related makeup sources were also available. The inspectors noted that although the ability to split the trains was compromised, the component cooling water system could have met its intended safety function despite the condition, with adequate normal and backup makeup systems available. This finding was determined to be of very low safety significance (Section 4OA2).

Cornerstone: Occupational Radiation Safety

- Green. On February 13, 2003, the inspectors identified a violation of Technical Specification 5.4.1 for failure to follow radiation work permit requirements. Specifically, radiation workers failed to contact radiation protection personnel prior to working greater than 8 feet above the floor on Safety Injection Valve SI-2-8821B. This violation is being treated as a noncited violation consistent with Section VI.A.1 of the NRC Enforcement Policy.

  The issue was more than minor because the failure to follow radiation work permit requirements has the potential for unplanned or unintended dose which could have been significantly greater as a result of higher radiation or contamination levels. The safety significance of this finding was determined to be very low by the Occupational Radiation Safety Significance Determination Process because it did not involve as low as reasonably achievable (ALARA) planning and controls, there was no personnel overexposure, there was no substantial potential for personnel overexposure, and the finding did not compromise the licensee's ability to assess dose (Section 2OS1).

B. <u>Licensee-Identified Violations</u>

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

Report Details

Summary of Plant Status

Diablo Canyon Unit 1 began this inspection period at 100 percent power. On January 14, 2003, operators reduced reactor power to 85 percent to accommodate the placement of the main turbine digital electrohydraulic control unit back into service. Unit 1 returned to 100 percent power on the same day and remained at this power level for the rest of the inspection period.

Diablo Canyon Unit 2 began this inspection period at 100 percent power. On January 22, operators began a coastdown of Unit 2 reactor power prior to Refueling Outage 2R11. On February 3 reactor power was at 92 percent when operators commenced a reactor shutdown and entered Mode 3 (Hot Standby). Operators initiated a plant cooldown and entered Mode 4 (Hot Shutdown) on February 3 and Mode 5 (Cold Shutdown) on February 4. On February 7, Unit 2 entered Mode 6 when maintenance personnel de-tensioned the reactor vessel head. On February 10, operators commenced core offload and completed the core offload 2 days later. The operators reloaded the reactor core over a 3-day period beginning on February 20. Unit 2 entered Mode 5 when the reactor vessel head was tensioned on March 9. Operators commenced a reactor coolant system (RCS) heatup, and Unit 2 entered Mode 4 on March 12 and attained Mode 3 on March 15. With the plant in Mode 3 operation, the licensee identified a high leakoff rate on the Reactor Coolant Pump 2-1 seal. The unit was returned to Mode 5 on March 18 to facilitate repairs. The unit was returned to Modes 4 and 3 on March 23. On March 24, operators commenced a reactor startup, entering Mode 2 (Startup). Mode 1 (Power Operation) was achieved on March 26. The refueling outage (2R11) ended on the same day when operators synchronized the main generator to the grid. Subsequently, high electrical noise was identified on Excore Neutron Detector N-42. Operators shut down the Unit 2 reactor and entered Mode 3 on March 28. Following repairs, operators commenced a reactor startup on March 29, entering Mode 2. At the completion of the inspection period on March 29, Unit 2 was in Mode 2 at one percent power.

1. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignments (71111.04)

Partial System Walkdowns

.1 Unit 2 Residual Heat Removal (RHR) Containment Recirculation Sump

a. Inspection Scope

On March 10, 2003, during preparations for Unit 2 restart, the inspectors walked down the Unit 2 RHR containment recirculation sump. The inspectors reviewed the structural integrity of the sump and verified the absence of foreign material that may impact the operability of the RHR pumps in the postaccident recirculation mode. Additionally, the inspectors walked down the Unit 2 containment following cleanup activities to verify foreign material had been removed that may impact the RHR containment recirculation sump. Procedure STP M-45A, "Containment Inspection Prior to Establishing Containment Integrity," Revision 19, was used during the inspection.

b. Findings

No findings of significance were identified.

.2 Unit 1 Centrifugal Charging Pump (CCP) 1-1

a. Inspection Scope

On March 19, 2003, while CCP 1-2 was in a maintenance outage window, the inspectors performed a partial system walkdown of CCP 1-1. The inspectors observed valve alignment, the availability of electrical power and cooling water, labeling, lubrication, ventilation, structural support, and material condition. The following documents were used to support the inspection:

- Drawing 106709, “Safety Injection,” Sheet 3, Revision 53
- Drawing 663219, “Mechanical - 8 inch - 150 lb. Gate Valve RS Cast Stainless Steel Butt Weld Ends Stellite Trim - Seal W.B. Motor Operated,” Sheet 458, Revision 24
- Action Request (AR) A0359273, “9001A/B & 8805B-QSS Installation. CSP 1-1 Discharge Valves”

b. Findings

No findings of significance were identified.

.3 Unit 1 Component Cooling Water (CCW) Pump 1-2 and 1-3

a. Inspection Scope

On March 26, 2003, while CCW Pump 1-1 was in a maintenance outage window, the inspectors performed a partial system walkdown of CCW Pumps 1-2 and 1-3. The inspectors observed valve alignment, the availability of electrical power and cooling water, labeling, lubrication, ventilation, structural support, and material condition. The following documents were used to support the inspection:

- Drawing 106714, “Component Cooling Water”
  - Sheet 2, Revision 45
  - Sheet 4, Revision 49
  - Sheet 9, Revision 49
- Procedure OP F-2:I, “Component Cooling Water System - Make Available,” Revision 24

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors performed 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 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, and STP M-70C, “Inspection/Maintenance of Doors,” Revision 8. Specific risk-significant areas inspected included:

- Units 1 and 2 Turbine Building
- Units 1 and 2 Intake Structure
- Units 1 and 2 Switchgear Rooms
- Units 1 and 2 Auxiliary Building
- Units 1 and 2 Fuel Handling Building

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

Performance of Nondestructive Examination (NDE) Activities Other than Steam Generator Tube Inspections

The inspectors observed the licensee and its contractor NDE personnel perform the ASME Code Section XI examinations listed below:

System	Component/Weld Identification	Examination Method
Reactor Coolant	Pipe to Elbow Line 16-14 No. WIB-436	Ultrasonic Examination
Reactor Coolant	Elbow Line 16-14	Ultrasonic Examination
Main Steam	Welded Attachment Line 2K15-227-28V	Magnetic Particle Examination

During the performance of each examination, the inspectors determined whether the licensee used the correct NDE procedure, the licensee met the procedural requirements specified in the procedure, and the licensee used properly calibrated test instrumentation or equipment. The inspectors checked whether the licensee compared the indications revealed by the examinations against the previous outage examination reports.

The inspectors found the licensee performed 19 welding repairs under Section III of the ASME Code for Class 1 and 2 components since the last outage. The inspectors reviewed a sample of three work orders on the replacement of feedwater piping and reactor coolant and containment spray valves. The inspectors reviewed the radiographic film of the replacement welding and evaluated whether the repair activities met ASME Code requirements.

The inspectors found the licensee planned 10 repair/replacement activities during the current outage. None of the activities took place during the inspection window.

Steam Generator (SG) Tube Inspection Activities

The inspectors reviewed the leakage history for the SGs to verify that the leakage was less than 3 gallons per day during operations. The licensee and its contractors used properly qualified eddy current probes and equipment for the expected types of tube degradation. The inspectors observed the collection and analysis of eddy current data by contractor personnel performed to evaluate tubes and a possible loose part in an SG. The inspectors observed whether the licensee reviewed the areas of potential degradation based on site-specific and industry experience. The recent industry experience included the events which occurred at the Comanche Peak Plant late in 2002. The inspectors questioned whether the licensee compared flaws detected during the current outage against the previous outage data. The inspectors reviewed the repair criteria used. The inspectors also verified that the licensee’s eddy current examination scope and expansion criteria met the Technical Specifications, industry guidelines, and commitments to the NRC.

At the time of the inspection, the licensee had not established the scope of in-situ pressure testing. The inspectors evaluated whether predictions of tube plugging were the same as experienced in the past. SG tube plugging had not begun at the time of the inspection.

Identification and Resolution of Problems

The inspectors reviewed condition reports/disposition requests issued during the past 18 months and reviewed in detail 12 ARs and one nonconformance report on steam generator eddy current inspection activities. The licensee issued these ARs in the past 2 years on the subject of inservice inspection and steam generator eddy current inspection activities. The inspectors ascertained whether the licensee identified, evaluated, corrected, and trended problems.

b. Findings

The licensee reported the primary-to-secondary leakage as greater than 3 gallons per day, peaking at 6.5 gallons per day. This information was discussed with the NRC's Office of Nuclear Reactor Regulation during the operating cycle. Subsequent eddy current and hydrostatic testing performed during the Unit 2 refueling outage established a significant increase in defects in tubes at the U-bend region and at the tube support plates. The secondary leakage rate and the characterization of the eddy current results and the hydrostatic testing were reviewed as part of the special inspection (see NRC Inspection Report 50-323/03-09) conducted regarding the condition of the Unit 2 SGs.

1R11 Operator Requalification (71111.11)

a. Inspection Scope

The inspectors witnessed operator performance in the simulator during routine training and requalification examinations. The inspectors reviewed the operators' ability to meet the objectives of the training scenario. On March 27, 2003, the inspectors observed a simulator scenario associated with a Loss-of-Offsite Power and a Loss-of-Coolant Accident.

The inspectors used Procedures EOP E-0, "Reactor Trip or Safety Injection," Revision 27, and EOP E-1, "Loss of Reactor or Secondary Coolant," Revision 18, to support the inspection activities.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Reviews

a. Inspection Scope

The inspectors reviewed the licensee'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 9, was used as guidance. The inspectors reviewed the following ARs:

- A0573129, "Maintenance Rule Performance Goal Setting Review," and A0569592, "N-32 Failed," for Source Range Instrument N-32 (Unit 1)

- A0503633, "Maintenance Rule Performance Criteria, Goal Setting Review," for Diesel Engine Generator 1-3 (Unit 1)

- A0565683, “Maintenance Rule Performance Criteria, Goal Setting Review,” for Unit 1 Main Generator" (Unit 1)

b. Findings

No findings of significance were identified.

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

.1 Risk Assessments

a. Inspection Scope

The inspectors reviewed daily work schedules and compensatory measures to confirm that the licensee had performed proper risk management for routine work. The inspectors considered whether risk assessments were performed according to their procedures and the licensee had properly used their risk categories, preservation of key safety functions, and implementation of work controls. The inspectors used Procedure AD7.DC6, “On-line Maintenance Risk Management,” Revision 6, and AD8.DC51, “Outage Safety Management Control of Off-Site Power Supplies to Vital Busses,” Revision 7B, as guidance. The inspectors specifically observed the following work activities during the inspection period:

- (Unit 1) RHR Pump 1-1, Control Room Ventilation System Fan CR-36, and Positive Displacement Pump 1-3 maintenance on January 23, 2003

- (Unit 2) Hot Midloop Operation

b. Findings

Introduction. A violation (noncited) of Technical Specification 5.4.1.a was identified by the inspectors for the failure to adequately implement outage safety management controls. This noncited violation was determined to be of very low safety significance (Green). Specifically, the licensee implemented planned maintenance work activities in the area of the Unit 2 offsite power source (Startup Transformer 2-2), during midloop operations, that could have either directly or indirectly affected the single offsite power source without performing a detailed schedule review of all the work activities related to the single operable power source by the outage organization and without the authorization of the shift foreman.

Description. The licensee had initially planned to enter hot midloop operations on February 6, 2003. Three days later the licensee had planned to begin replacing 500 kV line insulators, some of which were located in the area of Startup Transformer 2-2. Subsequently, midloop operations were delayed until the morning of February 7, with the 500 kV line insulator replacement starting on February 6. The insulator replacement continued during the period the plant was in midloop. Prior to entering midloop operations, the licensee had assessed the risk associated with removing the 500 kV offsite power source and one of three Vital 4 kV buses. This configuration left Unit 2 with one offsite power source which was supplied through Startup Transformers 2-1 (230 kv to 12 kv) and 2-2 (12 kv to 4 kv). The available onsite power sources included two diesel generators that could connect to the two operable vital 4 kV buses as well Unit 1 auxiliary saltwater crosstie capability.

To facilitate replacement of the 500 kv line insulators, a bucket truck was brought in and positioned within 15 feet of Startup Transformer 2-2. The truck's boom, when extended, had a reach of at least 100 feet. The truck was being used to replace 500 kV line insulators, which were hung from the turbine building. The inspectors noted that the approval for performing the insulator work was provided by the midloop coordinator and another licensed senior reactor operator; however, the inspectors determined that the shift foreman was not aware of the bucket truck and the work that was being performed in the area of Startup Transformer 2-2. The inspectors then considered the detailed outage schedule review that had been performed and determined that the review did not include the level of detail commensurate with the original schedule or that a bucket truck, used to replace the insulators, would be operating next to Startup Transformer 2-2 while the Unit 2 RCS was at midloop.

Procedure AD8.DC51, "Outage Safety Management Control of Off-Site Power Supplies to Vital Buses," Revision 7B, requires, in part, that a detailed schedule review of all the work activities related to the single operable power source has been performed by the outage organization. This work shall include any work that is to be performed in the vicinity of the Startup Transformers. The procedure also requires that all work that has been identified as a potential to directly or indirectly affect the single operable offsite power source shall not be allowed at any time without the authorization of the outage manager and the approval of the shift foreman.

Analysis. Procedure AD8.DC51, "Outage Safety Management Control of Off-Site Power Supplies to Vital Buses," Revision 7B, discussed industry experience with loss-of-offsite-power events during shutdown. The outage safety plan stated that 37 losses of offsite power occurred between 1965 and 1990, and 18 of those were the result of human error. Between March and April of 2000, there were 5 losses of decay heat removal events in the industry due to loss of power caused by maintenance or clearance activities. Similar experience is also documented in Information Notice 90-25, "Loss of Vital AC Power With Subsequent Reactor Coolant System Heat-up."

The deficiency associated with this finding is a failure to follow Procedure AD8.DC51, which required shift foreman approval and a detailed schedule review for work that could directly or indirectly affect the single operable offsite power source. The finding was more than minor since a significant outage work activity was not approved by the shift foreman during a period when industry experience has demonstrated the potential for significant events to occur. NRC Manual Chapter 0609, Appendix G, Shutdown Operations - Significance Determination Process," dated February 27, 2001, was utilized to assess the overall safety significance. Table 1 for Reactor Coolant System Open and Refueling Cavity Level< 23', Section III.A , Power Availability Guidelines-Procedures/ Training/Administrative Controls, considers that work activities do not have significant potential to affect existing operable power supplies and that there is control over switchyard and transformer yard activities. The finding is of very low risk significance since the truck was moved into position prior to midloop operation, a safety assessment was performed prior to the outage work activity beginning, and the shift foreman subsequently approved the work to continue without revision to the work safety assessment or the work plan.

Enforcement. Technical Specification 5.4.1.a requires written procedures to be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A. Regulatory Guide 1.33, Appendix A, Item 3.s(1), requires procedures be implemented for the operation and shutdown of offsite electrical systems (i.e., access circuits). Contrary to the above, Procedure AD8.DC51 was not followed in that a bucket truck was operated next to Startup Transformer 2-2 that could have directly or indirectly affected the single source of offsite power without shift foreman knowledge of the activity or detailed schedule review having been performed by the outage organization. Because the failure to implement adequate outage safety control over offsite power sources was of very low safety significance and has been entered into the corrective action system as AR A0574789, this violation is being treated as a noncited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-323/03-05-01, Failure to Implement Outage Safety Management Control of Offsite Power Sources.

.2 Emergent Work

a. Inspection Scope

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

- Unit 1, Technical Specification 3.0.3 entry on February 19 due to Control Room Door 508 failed latch

- Unit 2, Reactor Coolant Pump 2-1 Seal replacement on March 18-22

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

For the nonroutine events described below, the inspectors reviewed operator logs, plant computer data, and strip charts to determine what occurred and how the operators responded and to determine if the response was in accordance with plant procedures:

(Unit 2) On March 10, 2003, during a walkdown of the control boards, an operator noticed that the controller for all three power-operated relief valves (PORVs) was in the “closed” position versus the “auto” position. This configuration prevented the Low Temperature Overpressure Protection feature from opening the PORVs and relieving pressure in the event of a RCS overpressure while in Mode 5. This condition lasted for approximately 23 hours and was documented in AR A0577809. The inspectors reviewed the licensee’s actions prior to, during, and following the event. Additional description of the event is provided in Section 40A7.

b. Findings

The findings are discussed in Section 40A7.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed operability evaluations and supporting documents to determine if the associated systems could meet their intended safety functions despite the degraded status. The inspectors reviewed the applicable Technical Specifications, Codes/Standards, and Final Safety Analysis Report (FSAR) Update sections in support of this inspection. The inspectors reviewed the following operability evaluations:

- Unit 1 Centrifugal Charging Pump 1-1 Mechanical Seal Leakage (ARs A0436116 and A0573103)
- Unit 1 Auxiliary Building Ventilation Air Plenum Door 410 (AR A0575844)
- Unit 2 Investigate and Repair Breakers 52VU23 and 52VU24 (AR A0576690)
- Unit 1 Diesel Engine Generator 1-3 failed to start within Technical Specifications time (AR A0576110)
- Unit 1 Steam Generators considering Unit 2 Steam Generator tube inspection results (Operability Evaluation 2003-02)

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

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

- Unit 2, Containment Purge Air Exhaust Valve VAC-2-RCV-12, Replace copper tubing with stainless steel tubing on January 14 (AR A0563962)
- Unit 2, Diesel Engine Generator 2-2, Repair electrohydraulic transducer in hydraulic actuator of Woodward hydraulic governor on February 25 (AR A0576118)

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors witnessed and evaluated licensee performance during the 11th refueling outage for Unit 2. The outage lasted from February 3 to March 26, 2003. Before and during the outage, the inspectors evaluated the licensee'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 Technical Specification requirements. Specifically, the inspectors observed the licensee'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 defueling 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 regard to Technical Specification 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 Technical Specifications and outage risk plans

- Adequate control of reduced inventory and midloop conditions
- Movement of heavy loads inside containment and the turbine building
- Operator overtime usage

b. Findings

.1 Loss of Containment Closure

Introduction: An unresolved item, pending completion of inspection activities, was identified for the failure to promptly notify the shift foreman when it was ascertained that containment closure could not be established during reduced inventory operations because of an obstruction that prevented the fuel transfer tube isolation valve from being closed. The licensee calculated that during a 2.5 hour period that the fuel transfer tube could not be isolated, the RCS could potentially begin boiling within 22 minutes if shutdown cooling was lost.

Description. On February 8, 2003, during testing of the Unit 2 fuel transfer cart, the cart became stuck in the closing path of fuel transfer tube isolation Valve SFS-2-50. A fitting in the cable retract mechanism became loose because it was installed improperly. Personnel performing this test were unaware that this task breached the containment boundary and the containment coordinator did not inform the shift foreman of the condition until 1.5 hours later. Approximately an hour later the shift foreman completed development of a contingency plan to restore containment closure capability in the event of a loss of RHR. If a loss of RHR had occurred during this time period, containment closure, using fuel transfer tube isolation Valve SFS-2-50, could not have been met prior to core boiling as specified. The licensee initiated AR A0574018 and placed this item into the corrective action program.

The inspectors identified that the prejob briefings did not inform the workers the test of the fuel transfer cart involved breaching the containment boundary and of the need to immediately inform the control room in the event that Valve SFS-2-50 could not be closed. In addition, the licensee did not ensure that adequate contingencies were developed prior to beginning spent fuel transfer cart testing to ensure that containment closure capability could be restored in an expeditious manner if problems occurred.

Analysis

The inspectors determined that this issue affected the barrier integrity cornerstone and was more than minor. This finding impacted the reactor safety area. The licensee credited the ability to close containment during outage conditions of reduced inventory within 30 minutes. The licensee calculated the time to boil, with vessel level below the level of the reactor vessel flange at 112 feet, at 22 minutes. In the event of a loss of RHR, containment closure could not have been accomplished within the time to boil. The inspectors noted that both RHR pumps remained operable and decay heat was adequately removed from the core throughout the event. The inspectors determined that this issue affected the Barrier Integrity Cornerstone and was more than minor since it affected the Configuration Control Attribute for containment. NRC Manual Chapter 0609, Appendix G, "Shutdown Operations - Significance Determination Process," dated February 27, 2001, was utilized to assess the overall safety significance. Table 1 for RCS Open and Refueling Cavity Level< 23', Section IV.A , Containment Control Guidelines-Procedures/Training considers that training procedures and administrative controls are implemented to close containment prior to core boiling if the RCS is open. This finding was determined to degrade the ability of containment to remain intact following a severe accident; therefore, a Phase 3 significance determination process assessment will be performed. This finding is unresolved pending completion of the inspection activity to determine the overall safety significance (URI 50-323/03-05-02).

Enforcement. Technical Specification 5.4.1.a requires written procedures to be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Appendix A. Regulatory Guide 1.33, Appendix A, Item 3.f, requires procedures be implemented for the operation and shutdown of safety-related pressurized water reactor (PWR) systems, including maintaining containment. Contrary to the above, Procedure AD8.DC54, Containment Closure," Revision 8, paragraph 5.1.4.b, requires in part that, if any hatch or the fuel transfer tube cannot be closed within the calculated time to boil, the shift foreman shall be informed. The NRC inspectors identified that the licensee had not informed the shift foreman in a timely manner, relative to the calculated time to boil, to ensure that the fuel transfer tube could be isolated in the event of a loss of shutdown cooling. This item has been entered into the corrective action system as AR A0574018. The characterization of the violation will remain open as part of the unresolved item, pending completion of the inspection activity to assess the overall safety significance.

.2 Reactor Vessel Refueling Level Instrumentation System Difference

Introduction. A finding of very low safety significance (Green) was identified for activities associated with filling the pressurizer relief tank during midloop operations, which resulted in unexpected decreases in reactor vessel level indication. This finding was self-revealing.

Description. The Reactor Vessel Refueling Level Instrumentation System (RVRLIS) is utilized during reduced reactor vessel inventory operations and refueling activities to monitor reactor vessel level inventory and ensure adequate level is maintained to support shutdown cooling. During reduced inventory operations, the RVRLIS system provides level feedback to operators for lowering and maintaining reactor vessel level. If level is not maintained above 107 feet, decay heat removal (shutdown cooling) could be lost due to vortexing and cavitation of the RHR pumps.

On March 8, 2003, operators observed deviations between three different instruments in the RVRLIS. The standpipe and the wide-range level transmitters indicated an approximate 4 inches lower level than the narrow-range level transmitter. Operators were directed by their procedures to follow the narrow-range level transmitter if there are discrepancies between level indications. Additionally, an ultrasonic level transmitter read a lower reactor vessel level. At the time of the level discrepancy, operators were filling the pressurizer relief tank (PRT), and maintenance personnel were removing the first cold leg nozzle dam. Operators were aware that removal of the first cold leg nozzle dam may cause a lower RVRLIS level indication. The operators halted the filling of the pressurizer relief tank and determined that the reason for the lower level indications resulted from the removal of the first cold leg nozzle dam. The wide-range level indication recovered and closely matched the narrow-range level. When operators resumed filling of the PRT, the wide-range and standpipe level indications again read lower than the narrow-range level by approximately 3 inches. Operators halted the PRT filling to determine the cause of the level discrepancy. It was later determined by operators that the PRT airspace conversed with the reference legs of both the standpipe and the wide-range RVRLIS transmitter. In previous midloops, the PRT airspace was vented to the containment purge system. However, due to level fluctuations caused by the starting of the containment purge exhaust fans, licensee personnel decided to vent the PRT to a polybottle with a filtered vent. While the polybottle allowed for equalization with atmospheric pressure, the sudden pressure surge caused by filling the PRT resulted in a pressure difference between atmospheric pressure and the air pressure inside the PRT that caused the wide-range and standpipe level readings to indicate the lower levels because of the higher pressure (level) sensed on the reference legs. The narrow-range RVRLIS instrument was not effected.

Analysis. The inspectors determined that the finding is a performance deficiency since inadequate planning for PRT filling caused inaccurate RVRLIS wide-range and standpipe level indications. The inspectors reviewed Administrative Procedure OP A-2:III, “Reactor Vessel-Draining to Half Loop/Half Operations With Fuel in the Vessel,” Revision 22. The inspectors found that the procedural requirements were met in that no initiations of transient conditions were induced while at midloop operation. However, the finding was more than minor because an initiating event cornerstone attribute, involving shutdown equipment instrumentation was potentially affected. NRC Manual Chapter 0609, Appendix G, Shutdown Operations - Significance Determination Process,” dated February 27, 2001, was utilized to assess the overall safety significance. Table 1 for RCS Open and Refueling Cavity Level < 23', Section II.B, Inventory Control Guidelines-Procedures/Training, considers that training procedures and administrative controls are implemented to avoid operations that could lead to perturbations in RCS level control or decay heat removal flow. The issue was determined to involve change in indication only and therefore was assessed as having very low safety significance. This finding is documented in the licensee’s corrective action system as AR A0577709.

Enforcement. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because procedures for reduced inventory operations were met (50-323/03-05-03).

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- Procedure STP M-77, “Safety and Relief Valve Testing,” Revision 26, on January 22 for Unit 2
- Procedure STP M-13G, “4kV Bus G Non-SI Auto-Transfer Test,” Revision 26, on February 25 for Unit 2
- Procedure STP M-9A, “Diesel Engine Generator Routine Surveillance Test,” Revision 63, on March 18 for Unit 2
- Procedure STP M-21B, “Main Turbine Overspeed Trip Tests,” Revision 17, on March 25 for Unit 2
- Procedure STP P-AFW-21, “Routine Surveillance Test of Turbine-Driven Auxiliary Feedwater Pump 2-1,” Revision 14, on March 26 for Unit 2

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

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

- Unit 2, Diesel Engine Generator 2-1 jumper to supply power to the lube oil heater on January 31

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

The inspectors reviewed and assessed the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, and high radiation areas. The inspectors interviewed supervisors, radiation workers, and radiation protection personnel involved in high dose rate and high exposure jobs during Refueling Outage 2R11. The inspectors discussed changes to the access control program with the Radiation Protection Manager. The inspectors also conducted plant walkdowns within the radiological controlled area and conducted independent radiation surveys of selected work areas. The following items were reviewed and compared with regulatory requirements:

- Area postings, radiation work permits (RWPs), radiological surveys, and other controls for airborne radioactivity areas, radiation areas, and high radiation areas

- High radiation area key control

- Internal dose assessment for exposures exceeding 50 millirem committed effective dose equivalent

- Setting, use, and response of electronic personal dosimeter alarms

- ALARA prejob briefing prior to entry into the regenerative heat exchanger room, a locked high radiation area

- Conduct of work by radiation protection technicians and radiation workers in areas with the potential for high radiation dose and the associated RWPs, radiological surveys, and controls for the work during Refueling Outage 2R11, specifically: RWP 03-2002-0, “2R11 Scaffolding in Containment”; RWP 03-2013-0, “2R11 Temporary Shielding in Containment”; RWP 03-2031-01, “2R11 Regenerative Heat Exchanger Room Work”; RWP 03-2042-0, “2R11 S/G Nozzle Dam Installation and Removal”; and RWP 03-2044-0, “2R11 Primary S/G Eddy Current Testing, Tube Plugging, Plug Pulling, and other tube related activities”

- Dosimetry placement when work involved a significant dose gradient

- Controls involved with the storage of highly radioactive items in the spent fuel pool

- Audits, licensee event reports, special reports, and self-assessments involving high radiation area controls and staff performance, specifically, EDMS 022210002, “2002 Radiological and Environmental Monitoring Program and Offsite Dose Calculation Procedure Program Audit”; EDMS-21490006, “1R11 Radiation Protection Performance Assessment”; and Radiation Protection Assessment Report 021790004, “Control of Access to High Radiation Areas”

- Selected corrective action documents involving high radiation area incidents, radiation protection technician and radiation worker errors, and repetitive or significant individual deficiencies written since May 1, 2002. Specifically, six of these documents reviewed in detail: A0560747, A0561859, A0561868, A0563738, A0573453, and A0573890

b. Findings

Introduction. The inspectors identified a Green NCV because the licensee failed to follow RWP requirements.

Description. On February 13, 2003, the inspectors and a licensee representative toured the Unit 2, auxiliary building, 110-foot piping penetration room. The inspectors identified that a ladder had been placed beneath Safety Injection Valve SI-2-8821-B. The valve was located in the overhead, greater than 8 feet above the floor. The inspectors asked whether personnel had worked on the above valve. The licensee determined that two workers had worked on the valve and had not contacted radiation protection personnel. The RWP used for the valve work required workers to contact radiation protection personnel prior to accessing areas greater than 8 feet above the floor. Not contacting radiation protection personnel to verify radiation and contamination levels prior to working in an area where radiological conditions could change could have resulted in unintended exposure. See Section 4OA7 for a similar licensee-identified violation.

Analysis. The failure to follow RWP requirements is a performance deficiency. The finding was more than minor because it was associated with one of the cornerstone attributes (procedures) and the finding affected the Occupational Radiation Safety cornerstone objective (adequate protection from exposure). Because the finding involved the potential for unplanned, unintended dose resulting from conditions that were contrary to the RWP, the finding was evaluated using the Occupational Radiation Safety Significance Determination Process. The inspectors determined that the finding had no more than very low safety significance because it did not involve ALARA planning and controls, there was no personnel overexposure or substantial potential for personnel overexposure, and the finding did not compromise the licensee’s ability to assess dose.

Enforcement. Technical Specification 5.4.1 states, in part, that written procedures shall be established, implemented, and maintained covering applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, Section 7e, requires radiation protection procedures for access control to radiation areas, including an RWP system. The failure to contact radiation protection personnel prior to entering areas greater than 8 feet as required by the RWP is a violation of Technical Specification 5.4.1. This violation is in the licensee's corrective action program as AR A0574654. This violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 50-323/03-05-04, Failure to Follow Radiation Work Permit Requirements.

2OS2 ALARA Planning and Controls (7112102)

a. Inspection Scope

The inspectors interviewed radiation workers and radiation protection personnel throughout the radiologically controlled area to determine their knowledge of ALARA practices and conducted independent radiation surveys of selected work areas. No work was performed in high exposure or high radiation areas during the inspection. Therefore, this aspect of the above inspection procedure was not evaluated. The following radiation protection program controls, planning, and preparation items were reviewed and compared with regulatory requirements to assess whether the licensee had an adequate program to maintain occupational exposure ALARA during the upcoming Unit 2 Refueling Outage 2R11:

- ALARA program procedures
- Processes used to estimate and track personnel exposures
- Plant collective exposure history for the past 3 years, current exposure trends, and 3-year rolling average dose information
- ALARA and radiological work planning for six RWP packages that could result in some of the highest personnel collective exposures during the upcoming Refueling Outage 2R11 (RWP 03-2002-0, "2R11 Scaffolding in Containment;" RWP 03-2012-0, "2R11 Insulation in Containment;" RWP 03-2020-0, "2R11 Reactor Disassembly;" RWP 03-2027, "Reactor Reassembly;" RWP 03-2042-0, "2R11 Steam Generator Dam Installation and Removal;" and RWP 03-2044-0, "2R11 Primary Steam Generator Eddy Current Testing, Tube Plugging, Plug Pulling and other tube related activities")
- Hot spot tracking and reduction program
- Use of engineering controls to achieve dose reductions, including six temporary shielding request (TSR) packages planned for installation during the upcoming Refueling Outage 2R11 (TSR 03-0202, TSR 03-0210, TSR 03-0217, TSR 03-0234, TSR 03-0244, and TSR 03-0255)

- Individual exposures of selected work groups (radiation protection and chemistry, operations, and maintenance)

- Job site inspection and ALARA controls (prejob briefing and work activities controlled by RWP 03-00009-0 to determine the rate of seal leakage on Charging Pump 1-1)

- Plant-related source term data, including source term control strategy

- ALARA Advisory Council meeting minutes (July 11, 2002; August 15, 2002; October 10, 2002; November 7, 2002; December 19, 2002; and January 23, 2003)

- ALARA Review Committee meeting minutes (June 11, 2002; August 27, 2002; October 24, 2002; and November 26, 2002)

- Four radiation protection department self-assessments (“1R11 Radiation Protection Performance,” performed in June 2002; “2R11 Receipt of New Fuel” performed October 30 through November 15, 2002; “Control of Access to High Radiation Areas” performed July 16-19, 2002; and “Surface Contaminated Area Posting Program” performed September 15 through October 18, 2002)

- A summary of radiological worker performance and ALARA related ARs written between July 26, 2002, and January 24, 2003, with the following six AR’s reviewed in detail (A0563292, A0563320, A0568512, A0569288, A0569538, and A0571273).

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection (PP)

3PP4 Security Plan Changes (71130.04)

a. Inspection Scope

The inspectors reviewed the following Physical Security Plan change to determine if the change decreased the effectiveness of the Physical Security Plan and to determine if requirements of 10 CFR 50.54 (p) were met:

- Physical Security Plan, Revision 22, dated January 31, 2003

The inspectors determined that the change reflected recent guidance for obtaining military employment history.

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 reviewed the following performance indicators for the period from the first quarter of 2002 through the fourth quarter of 2002 to assess the accuracy and completeness of the indicator. The inspectors reviewed plant operating logs and licensee monthly operating reports to support this inspection. The inspectors used NEI 99-02, "Regulatory Assessment Performance Indicator Verification," Revision 2, as guidance for this inspection.

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

b. Findings

No findings of significance were identified.

.2 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors reviewed corrective action program records involving locked high radiation areas (as defined in Technical Specification 5.7.2), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned exposure occurrences (as defined in NEI 99-02) for the past 12 months to confirm that these occurrences were properly recorded as performance indicators. Radiological controlled area entries with exposures greater than 100 millirems within the past 12 months were reviewed, and selected examples were examined to determine whether they were within the dose projections of the governing RWPs. Whole body counts or dose estimates were reviewed if radiation workers received committed effective dose equivalents of more than 100 millirems. Where applicable, the inspectors reviewed the summation of unintended deep dose equivalent and committed effective dose equivalent to verify that the total effective dose equivalent did not surpass the performance indicator threshold without being reported.

b. Findings

No findings of significance were identified.

.2 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors reviewed radiological effluent release program corrective action records, licensee event reports, and annual effluent release reports documented during the past four quarters to determine if any doses resulting from effluent releases exceeded the performance indicator thresholds (as defined in NEI 99-02).

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

Valve CCW-2-18 Liner Damage

a. Inspection Scope

The inspectors reviewed the licensee response to AR A0574583 and Non-Conformance Report (NCR) N0002156 which discussed liner damage to Valve CCW-2-18. The inspectors reviewed Procedure OP AP-11 "Malfunction of Component Cooling Water System," Revision 20, and Procedure E-1.4 "Transfer to Hot Leg Recirculation," Revision 8, the Bases for Technical Specification 3.7.7, and FSAR Update Section 9.2.2 to support this inspection.

b. Findings

Introduction. The inspectors identified a Green NCV for the failure to comply with 10 CFR Part 50, Appendix B, Criterion XI, which requires testing the ability of Valve CCW-2-18 to meet its design basis function of isolating a postulated leak between trains of CCW.

Description. The CCW consists of three pumps and two redundant trains. During normal operations, the CCW system is operated with the trains cross-connected. FSAR Update Section 9.2.2 and Technical Specification 3.7.7, Bases, Vital Component Cooling Water (CCW) System, stated that the CCW system could withstand a single passive failure for a leak of 200 gpm by manually isolating the two trains within 20 minutes. Valve CCW-2-18 was one of the valves necessary for closure to separate the trains of CCW.

On February 13, 2003, while performing work internally to Valve CCW-2-601, mechanics were able to observe that Valve CCW-2-18's seat liner had separated from its internals and was visibly displaced. The licensee initiated AR A0574583 to place this issue in the corrective action program. Upon inspection, the licensee discovered that approximately one half of the valve liner (180 degrees around) was missing and was in the CCW system. The licensee subsequently determined that Valve CCW-2-18 could not meet its design basis function as a postaccident boundary isolation valve to separate the two CCW trains. The licensee replaced the liner for Valve CCW-2-18 and verified that the repaired valve exhibited no seat leakage. The licensee believed that the valve had been damaged when used for a clearance boundary several years prior to discovery. The remaining seat material was recovered from the CCW system.

The inspectors noted that the licensee credited Valve CCW-2-18 in their safety analysis report, FSAR Update Section 9.2.2, and in the Technical Specification 3.7.7 Basis. In these references, the licensee identified that the CCW system could withstand a single passive failure leak of 200 gpm by closing the manual isolation valves within 20 minutes based on the volume of the CCW surge tank. Valve CCW-2-18 is one of the valves credited to isolate the two trains. However, the inspectors found that the licensee performed no leak testing of Valve CCW-2-18 to ensure that it was capable of meeting this design basis function. 10 CFR Part 50, Appendix B, Criterion XI, requires, in part, that testing shall be established to assure that structures, systems, and components will perform satisfactorily in service and incorporate acceptance limits contained in applicable design documents.

Analysis. The failure to provide adequate testing to ensure that Valve CCW-2-18 would meet its design basis function affects the mitigating systems cornerstone and is more than minor because it had an actual impact on safety. The lack of a test program to verify the ability of Valve CCW-2-18 to isolate a leak between trains of CCW, a damaged valve liner existed for an extended period of time, and the valve would not have met its design basis function.

The failure to provide adequate testing to ensure that Valve CCW-2-18 could meet its design basis function affected the Mitigating Systems Cornerstone and is more than minor because it had an actual impact on safety. Specifically, the lack of a test program allowed the existence of the damaged valve liner for a significant period of time. A Phase 3 significance determination process assessment was performed for a similar condition that occurred on Unit 1 (NRC Integrated Inspection Report 50-275/00-16; 50-323/00-16, Section 1R14.2). The Phase 3 assessment considered that a passive failure of one train of CCW (a low energy system) would have to occur prior to calling upon a comparable valve (Valve CCW-2-18) to perform its isolation function, a very low probability failure. The assessment also considered that a safety-related 250 gpm makeup source was available to replenish the CCW system. Two other nonsafety-related makeup sources were also available. The inspectors noted that, although the ability to split the trains was compromised, the CCW system could have met its intended safety function despite the condition, with adequate normal and backup makeup systems available. This finding was determined to be of very low safety significance.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XI, states, in part, that testing shall be established to assure that structures, systems, and components will perform satisfactorily in service and incorporates acceptance limits contained in applicable design documents. Contrary to this requirement, the licensee's test program did not assure that Valve CCW-2-18 could perform satisfactorily in service in accordance with design documents in that leak testing to demonstrate that Valve CCW-2-18 could be used to isolate a 200 gpm leak in a CCW train was not performed. Thus, valve liner damage went undetected for several years. This violation is in the licensee's corrective action program as AR A0574583. This violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 50-323/03-05-05, Failure to Perform Testing To Assure Valve Performance.

40A5 Other

.1 Evaluation of Diablo Canyon Safety Condition in Light of Financial Conditions

a. Inspection Scope

Due to the licensee's financial condition, Region IV initiated special review processes for Diablo Canyon. The resident inspectors continued to evaluate the following factors to determine whether the financial condition and power needs of the station impacted plant safety. The factors reviewed included: (1) impact on staffing, (2) corrective maintenance backlog, (3) corrective action system backlogs, (4) changes to the planned maintenance schedule, (5) reduction in outage scope, (6) availability of emergency facilities and operability of emergency sirens, and (7) grid stability (i.e., availability of offsite power to the switchyard, status of the operating reserves especially at the onset of rolling blackouts, and main generator volt-ampere reactive loading).

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

b. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs (NRC Bulletin 2002-02)

a. Susceptibility Ranking

The inspectors reviewed the susceptibility ranking calculation for Unit 2 contained in AR A0563116 which estimated effective degraded years accumulated on the reactor vessel head as of Refueling Outage 11. Specifically, the inspectors reviewed this calculation to verify that appropriate plant specific information was used as input and that an appropriate basis for the head temperature was used by the licensee to determine the reactor pressure vessel head susceptibility ranking.

b. Findings

No findings of significance were identified.

Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection

Temporary Instruction 2515/150, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Bulletin 2002-02),” Revision 1, provided guidelines to verify compliance with licensee commitments to NRC Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs." Further, this evaluation confirmed licensee compliance with applicable regulatory requirements (i.e., 10 CFR Part 50, Appendix A; 10 CFR Part 50, Appendix B; and 10 CFR 50.55a). As identified in the Temporary Instruction, Diablo Canyon Unit 2 fell within the category of moderate susceptibility plants. Consequently, the inspectors used the criteria for evaluating moderately susceptible plants to conduct this inspection.

a. Inspection Scope

From February 7-11, 2003, the inspectors conducted this performance-based evaluation and assessment to ensure that the NRC had an independent review of the condition of the reactor vessel head and vessel head penetrations. The inspectors assessed the effectiveness of the licensee examinations of the vessel head penetrations. Specifically, the inspectors: (1) attended the prejob briefing, (2) reviewed the examination criteria used by the examiners, (3) interviewed the examiners, (4) assessed adequacy of the examination plan and procedures, (5) observed in-process examinations, (6) evaluated the quality and resolution of the examination equipment, (7) reviewed completed records, (8) considered whether the licensee documented deficiencies in their corrective action process, and (9) assessed the overall effectiveness of the process used to perform the bare metal visual examination.

The inspectors reviewed the following documents during this inspection:

- NRC Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” dated August 3, 2001 [ADAMS Accession Number: ML012080284]

- Response to NRC Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” dated August 30, 2001 [ADAMS Accession Number: ML012570306]

- Supplement to Response to NRC Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” dated November 26, 2001

- Diablo Canyon Nuclear Power Plant, Units 1 and 2 Response to Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” (TAC Nos MB2627 and MB2628), dated February 26, 2002

- NRC Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” dated March 18, 2002 [ADAMS Accession Number: ML020770497]

- 15-Day Response to NRC Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” dated April 1, 2002

- NRC Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," dated August 9, 2002

- Diablo Canyon Units 1 and 2, 30-Day Response to Bulletin 2002-02, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs,” dated September 12, 2002

- MRP-48, EPRI TR-1006284, “PWR Materials Reliability Program Response to NRC Bulletin 2001-01,” dated August 2001

- Procedure ISI X-CRDM, “Reactor Vessel CRDM Inspection,” Revision 2A, dated May 1, 2002

- VT-2 Qualification Records for the Vessel Head Examination personnel

The inspectors observed five peripheral in-process vessel head penetration examinations performed using an articulated video probe and 14 in-process vessel head penetration examinations performed using a camera mounted on a robot crawler. The inspectors then evaluated the remainder of the vessel head penetration examinations by viewing videotapes made by the licensee of the examinations. In all, the licensee examined 14 of the peripheral vessel head penetrations using the articulated video probe because these penetrations were not accessible from the robot crawler and the licensee did not desire to remove the insulation to keep exposures ALARA. In addition, the inspectors visually evaluated the condition of the reactor vessel head from the two control rod drive mechanism cooling duct holes in the shroud.

b. Findings

No findings of significance were identified.

The inspectors concluded that the licensee inspected 100 percent of the general surface area of the reactor vessel head and all penetration tube bases at the reactor vessel head outer surface. The clarity and resolution of the examination equipment combined with the training, qualification, and procedures ensured that the examiners could detect small boron deposits. The inspectors have provided the following details of the inspection as required by Temporary Instruction 2515/150, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Bulletin 2002-02),” Revision 1.

Examination

The licensee established two teams with three inservice inspection examiners on each team in order to perform the examinations in an expedited manner. One individual on each team drove the robot and had obtained experience performing similar examinations at other facilities using robots. The three examiners coordinated the examination of the reactor vessel head penetration nozzles. The robot or the articulated video probe was moved in accordance with the established plan. A second individual verified the location on the scan plan and voice overlaid the video tape with the tape counter index value for the nozzle quadrant(s) being reviewed. The third individual independently verified the location on a second scan plan and documented the digital tape counts. The examiners established an indexing routine that evaluated the vessel head penetration nozzles in quadrants. The inspectors concluded that the scan plan implemented during the examinations ensured that the licensee had inspected all nozzles 360 degrees around the nozzle circumference.

The inspectors interviewed the personnel who performed the VT-2 examinations of the reactor vessel head. The inspectors verified that the examiners had current VT-2 qualification records as required and determined that all examiners had performed previous examinations at this site or at licensee partnership sites. During interviews, the inspectors found that the examiners knew how to identify indications of boric acid leakage and primary water stress corrosion cracking. The examiners had seen numerous photographs detailing leakage from vessel head penetrations. The licensee provided a training session that included: (1) the examination criterion and (2) photographs of vessel head penetrations with leakage and previously existing leakage stains.

The inspectors verified that Procedure ISI X-CRDM, “Reactor Vessel CRDM Inspection,” Revision 2A provided: (1) explicit descriptions of the types of boric acid indications that might be identified, (2) appropriate descriptions of the conduct of the examination (i.e., use of the scan plan), and (3) sufficient guidance to satisfy licensee commitments for inspection of the vessel head penetration nozzles and the general surface of the reactor vessel head. This procedure had undergone only minor revision since its first use on Unit 1 reactor vessel head inspection. The inspectors concluded that the procedure combined with the training had provided adequate guidance for the examiners to identify, disposition, and resolve deficiencies. The procedure stated that any deposits of boric acid shall be immediately investigated and emphasized that boric acid in the juncture of a vessel head penetration and the vessel head were of prime concern.

The inspectors reviewed the in-process sheet used to document the inspections and reviewed the completed surveillance documented in Procedure ISI X-CRDM. The work package accurately documented the condition of the reactor vessel head, documented the examination of each vessel head penetration, identified the qualification of the test equipment used, and identified personnel who performed the work. In addition to this quality record, the licensee had videotaped the examination process and had indexed the penetrations. The inspectors verified that the licensee had performed the required qualification examinations for the robot and the articulated video probe as required by the ASME Code.

The licensee used a robot especially for performing this bare metal examination of the vessel head and its penetrations. This robot was a new smaller robot than the one used on the previous Unit 1 examination and measured approximately 6½ inches long by 4½ inches wide by 1⅞ inches high.

The inspectors noted that the high resolution video equipment enabled the examiners to easily discern the type of debris (e.g., metal shavings or paint chips) located at the vessel head penetration area. The inspectors also determined that the camera on the robot provided up to 400 lines of resolution and concluded that the articulated video probe multiplied the images by a factor of 2 or 3, provided excellent resolution, and allowed Jaeger J-1 images to be easily discerned.

Condition of the reactor vessel head

During the head inspection, the inspectors noted that the reactor vessel head had no indications of boric acid leakage from the vessel head penetrations. This observation came from a complete review of the videotaped examination and direct observation of the head through the access areas. The inspectors noted only slight amounts of debris, dirt, and boron from other sources.

The inspectors noted that this vessel head had indications that water had been on top of the head at some time in the past as evidenced by areas of very light surface rust on the head in some areas, including the area immediately next to some vessel head penetrations. These indications did not, however, show any indications of metal loss in any location.

The inspectors noted that the vessel head had been painted with heat resisting aluminum paint. The inspectors noted that all of the vessel head penetration assemblies had a ring of paint on the nozzle assembly at the base where it met the vessel head and that much of the vessel head had paint adhered in spots or had peeled. The inspectors noted that this was easily discernable during the inspection process and did not interfere with the conduct of the examination.

Capability to identify and characterize small boron deposits

The inspectors concluded that the examiners and equipment used during the examinations could reliably detect and accurately characterize any identified leakage. The inspectors verified that the examiners: (1) consisted of the same group of individuals, (2) received the training on different types of boric acid indications, particularly what to expect if a leak occurred from a cracked vessel head penetration weld, (3) had a process for evaluation of deposits, and (4) used equipment with appropriate resolution.

During evaluation of the videotapes of the vessel head penetrations, the inspectors noted that the equipment provided excellent clarity that allowed for a complete evaluation. The inspectors found it easy to distinguish the size, type, consistency, and configuration of any identified debris.

Material deficiencies identified that required repair

None.

Impediments to effective examinations

The inspectors concluded that, in general, the licensee encountered no impediments to performing a qualified bare metal examination of the vessel head penetration nozzles. The only minor impediments encountered were when the licensee had to use an articulated video probe on the peripheral vessel head penetrations because of inadequate clearance for the robot.

The inspectors noted that on previous examinations, on the periphery where the insulation corners met, the examiners had to be more careful to ensure that all quadrants were examined because of the limited space. This concern was alleviated by using the newer smaller robot which allowed deeper access to these quadrants.

Basis for temperatures used in the susceptibility ranking calculation

The inspectors reviewed the bases for the 100 percent power reactor vessel head temperature used in the susceptibility ranking calculation for Unit 2 contained in AR A0563116. The inspectors concluded that the temperature licensee engineers used was supplied by the nuclear steam supply system vendor, Westinghouse, in WCAP-14919, “Probabilistic Evaluation of Reactor Vessel Closure Head Penetration Integrity for the Diablo Canyon Units 1 and 2,” dated July 1997. The inspectors also concluded that the value used for the 100 percent power reactor vessel head temperature matched the number the licensee provided in their response to NRC Generic Letter 97-01, “Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,” dated April 1, 1997, and contained in MRP-48, EPRI TR-1006284, “PWR Materials Reliability Program Response to NRC Bulletin 2001-01,” dated August 2001. The inspectors also conducted a qualitative comparison of the temperature value based on the plant’s normal operating temperatures and core internals design.

.3 (Closed) Unresolved Item 50-275;323/02-002-01: Evaluation of Ineffective Corrective Action to Prevent Recurrence of Previous Event of Startup Transformer 1-1 Grounding Transformer Fuse Box Electrical Fault.

During inspection 50-275;323/2002-02, the inspectors recognized a correlation between the Startup Transformer 1-1 grounding transformer fuse box event of August 4, 2001, and the Auxiliary Transformer 1-1 grounding transformer fuse box event of November 22, 1996. Nonconformance Report N0002130, “Loss of Unit 1 and 2 Startup Power,” identified the root cause of the Startup Transformer 1-1 grounding transformer fuse box event as moisture and airborne contaminates accumulating on the fuse insulators. The moisture and contamination facilitated the electrical phase-to-ground arcing, which destroyed the fuse box. Nonconformance Report N0002130 listed the contributory cause to the event as the ventilation louver, which was installed as a corrective action after the November 22, 1996, Auxiliary Transformer 1-1 grounding transformer fuse box event. The root cause of the 1996 event was determined to be poly-vinyl chloride (PVC) insulating boot degradation. The PVC boot degradation released chlorine gas, which combined with moisture to form hydrochloric acid. Corrosion from the hydrochloric acid attacked the bus duct and fuse box structure, resulting in the electrical arcing, which destroyed the fuse box.

The ventilation louver was installed to allow ionizing and chlorine gases to escape the fuse box and prevent future electrical faults within the fuse boxes. The licensee failed, at that time, to recognize that the louver also allowed the accumulation of salt deposits on the insulators from surrounding moisture laden air within the terminal box. The licensee subsequently closed off the fuse boxes from outside air and placed desiccant inside the box to preclude the buildup of moisture. The PVC insulating boots were also replaced with insulating material not susceptible to off-gassing.

The inspectors' initial Phase 2 evaluation of this issue using the Significance Determination Process indicated a condition that was potentially greater than Green. The inspectors determined that the installation of the ventilation louver, and the subsequent electrical fault associated with Startup Transformer 1-1 grounding the transformer fuse box, represented an actual impact on safety since the preferred offsite power was momentarily lost from both units.

The Phase 3 analysis was performed by the Office of Nuclear Reactor Regulation Probabilistic Safety Assessment Branch. The analysis indicated that the estimated change in core damage probabilities for internal and external events probabilities was 5.67E-7 and the change in large early release probability was 5.67E-8. The conclusion of the analysis characterized the performance deficiency as an issue of very low safety significance (Green).

Enforcement. The placement of ventilation louvers that introduced a new failure mechanism was not a violation of NRC requirements, but determined to be an NRC Finding 50-275/03-05-06, ineffective corrective action in placement of ventilation louvers on 12 kv grounding transformer.

40A6 Management Meetings

Exit Meeting Summary

The resident inspection results were presented on April 4, 2003, to Mr. David H. Oatley, Vice President and General Manager, and other members of licensee management. The licensee acknowledged the findings presented. Discussion of region-based inspection results are described in the following paragraphs.

The ALARA Planning and Controls inspection results were presented to Mr. D. Oatley, Vice President and General Manager, and other members of licensee management at the conclusion of the inspection on January 31, 2003. The licensee acknowledged the findings presented.

The Access Control to Radiologically Significant Areas inspection results were presented to Mr. L. Womack, Vice President - Nuclear Services, and other members of licensee management at the conclusion of the inspection on February 13, 2003. The licensee acknowledged the findings presented.

The Inservice Inspection Activities inspection results were presented to Mr. L. Womack, Vice President - Nuclear Services, and other members of licensee management on February 19, 2003. Licensee management acknowledged the inspection findings.

The Security Plan Changes inspection results were presented to Mr. Larry Parker, Licensing Supervisor, verbally on February 21, 2003. The licensee acknowledged the information presented.

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

40A7 Licensee-Identified Violations

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

- Technical Specification 5.4.1.a requires that procedures addressed in Appendix A of Regulatory Guide 1.33, Revision 2, be established, implemented, and maintained. Specifically, operating procedures for cold shutdown to hot standby are addressed in Regulatory Guide 1.33. On March 9, 2003, the licensee left the PORVs in the “close” position versus the “auto” position. This configuration would prevent an automatic open signal from the Low Temperature Overpressure Protection system from opening the valves and provide overpressure protection. This finding was identified in the licensee’s corrective action program as AR A0577809. This finding is of very low safety significance because an RHR suction relief valve was available for overpressure protection, no emergency core cooling system pumps were available except for a single centrifugal charging pump, and the time to boil exceeded 2 hours.

- Technical Specification 5.7.1 requires that high radiation areas be barricaded and posted. On February 6, 2003, the licensee identified that high radiation area boundaries were changed in the Unit 2 auxiliary building, 100 foot penetration room, such that a high radiation area of 120 millirem per hour around Safety Injection Valve SI-2-8804-B was not barricaded and posted for a period of approximately 17 hours. This violation is being treated as an NCV and is in the licensee’s corrective action program, reference AR A0573890. This finding is of very low (Green) safety significance because it was not an ALARA finding, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised.

- Technical Specification 5.4.1 requires RWP procedures. On January 24, 2003, the licensee identified that workers entered the overhead, greater than 8 feet above the floor, without contacting radiation protection personnel as required by the RWP. This finding is being treated as an NCV and is in the licensee's corrective action program, reference AR A0572742. This finding is of very low safety significance because it was not an ALARA finding, there was no overexposure or substantial potential for an overexposure, and the ability to assess dose was not compromised.

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Becker, Vice President - Diablo Canyon Operations and Station Director
S. Chesnut, Director, Engineering Services
J. Costantino, Team Leader, Radiation Protection
C. Gillies, Director, Site Services
R. Gray, Engineer, Radiation Protection
J. Hays, Director, Maintenance Services
B. Hite, Manager, Radiation Protection
R. Jett, Regulatory Services, NRC Interface Engineer
S. Ketelsen, Manager, Regulatory Services
M. Lemke, Manager, Emergency Preparedness
D. Miklush, Director, Engineering Services
P. Nugent, NSSS Engineering Manager
D. Oatley, Vice President and General Manager, Diablo Canyon
L. Parker, Licensing Engineer, Regulatory Services
J. Portney, NSSS Sr. Systems Engineer
P. Roller, Director, Operations Services
D. Taggart, Manager, Nuclear Quality Services Engineering, Procurement & Maintenance
J. Tompkins, Director, Nuclear Quality, Analysis, and Licensing
L. Womack, Vice President Nuclear Services
M. Wright, Manager, Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-323/03-05-02	URI	Failure to Implement Outage Safety management Control to Containment Closure (Section 1R20)

Opened and Closed

50-323/03-05-01	NCV	Failure to Implement Procedure to Control Bucket Truck Next to Single Supply of Offsite Power During Hot Midloop Operations (Section 1R13)
50-323/03-05-03	FIN	Failure to Control Work Activities Resulted in Reactor Vessel Level Indication Changes (Section 1R20)
50-323/03-05-04	NCV	Failure to Follow Radiation Work Permit Requirements (Section 2OS1)
50-323/03-05-05	NCV	Failure to Perform Testing To Assure Valve Performance (Section 4OA2)

50-275/03-05-06	FIN	Ineffective corrective action in placement of ventilation louvers on 12 kv grounding transformer fuse boxes (Section 4OA5.3)

Closed

50-275; 323/02-02-01	URI	Evaluation of Ineffective Corrective Action to Prevent Recurrence of Previous Event of Startup Transformer 1-1 Grounding Transformer Fuse Box Electrical Fault (Section 4OA5.3)

DOCUMENTS REVIEWED

Action Requests

A0532108	A0548781	A0556625	A0563925
A0538048	A0556015	A0560076	A0574268
A0548667	A0556467	A0562290	A0574572

Procedures

NDE ET-7, Eddy Current Examination of Steam Generator Tubing, Revision 2 with OTSC
NDE MT-1, Magnetic Particle Examination Procedure, Revision 11B
NDE PDI-UT-2, Ultrasonic Examination of Austenitic Piping, Revision 2
TQ1.ID12, Qualification and Certification of NDE Personnel, Revision 2
TS1.ID3, Steam Generator Management Program, Revision 4

Nonconformance Reports

N0002155

Work Orders

C0166252, Replace feedwater piping spools
C0173302, Replace auxiliary feedwater discharge check valve
R0158961, Replace vacuum breaker on the spray additive tank
R0202834, Replace pressurizer relief valve

Miscellaneous

Diablo Canyon Power Plant In-Service Inspection Program Plan, Revision 2

LIST OF ACRONYMS USED

ALARA	as low as reasonably achievable
AR	action request
CCP	centrifugal charging pump
CCW	component cooling water
CFR	Code of Federal Regulations
FSAR	Final Safety Analysis Report
NCV	noncited Violation
NDE	nondestructive examination
NRC	Nuclear Regulatory Commission
PORV	power-operated relief valve
PRT	pressurizer relief tank
PVC	poly-vinyl chloride
PWR	pressurized water reactor
RCS	reactor coolant system
RHR	residual heat removal
RVRLIS	reactor vessel refueling level instrumentation system
RWP	radiation work permit
SDP	significance determination process
SG	steam generator
TSR	temporary shielding request