U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos:	50-275/93-12 and 50-323/93-12
Docket Nos:	50-275 and 50-323
License Nos:	DPR-80 and DPR-82
Licensee:	Pacific Gas and Electric Company Nuclear Power Generation, B14A 77 Beale Street, Room 1451 P. O. Box 770000 San Francisco, California 94177
Facility Name:	Diablo Canyon Units 1 and 2
Inspection at:	Diablo Canyon Site San Luis Obispo County, California
Inspection Conducted:	April 13 through May 24, 1993
Inspectors:	M. Miller, Senior Resident Inspector F. Gee, Resident Inspector D. Kirsch, Technical Assistant

Approved by: P. Johnson, Chief, Reactor Projects Section 1 — 6/17/93, Date Signed

Summary:

Inspection from April 13 through May 24, 1993 (Report Nos. 50-275/93-12 and 50-323/93-12)

Areas Inspected: The inspection included routine resident inspector examination of plant operations; maintenance and surveillance activities; followup of onsite events; and selected independent inspection activities. Inspection Procedures 37700, 40500, 61707, 61708, 61710, 61726, 62703, 71707, 71710, 71711, 92701, and 93702 were used as guidance during this inspection.

Safety Issues Management System (SIMS) Items: None.

Results

General Conclusions on Strengths and Weaknesses

Strengths: Prompt action by a licensed operator mitigated a power increase caused by an unplanned dilution of reactor coolant system boron (Paragraph 4).

Weaknesses: Operations administrative controls failed to prevent two inadvertent insertions of reactivity due to boron dilution. One instance occurred at 100 percent power, the other during refueling (Paragraph 4).

Significant Safety Matters:

None

Summary of Violations:

None

Open Items Summary:

The inspectors opened one unresolved item and one followup item.

DETAILS

1. Persons Contacted

Pacific Gas and Electric Company

J. Townsend, Vice President and Plant Manager
W. Crockett, Manager, Technical and Support Services
*B. Giffin, Manager, Maintenance Services
*D. Miklush, Manager, Operations Services
*R. Powers, Manager, Nuclear Quality Services
*J. Bard, Director, Mechanical Maintenance
B. Budke, Senior Nuclear Generation Engineer
M. Burgess, Director, Systems Engineering
L. Bych, Senior Engineer, Nuclear Excellence Team
S. Chesnut, Senior Engineer, Plant Engineering
*K. Doss, Coordinator, HPES
R. Etner, Supervisor, Maintenance Services
*D. Farrer, Engineer, Reactor Engineering
*S. Fridley, Director, Operations
R. Etner, Supervisor, Maintenance Services
J. Gisclon, Senior Engineer, Nuclear Excellence Team
*T. Grebel, Supervisor, Regulatory Compliance
*C. Groff, Director, Plant Engineering
S. Hamilton, Senior Engineer, Operating Experience Assessment
*R. Hess, Assistant Onsite Project Engineer, Nuclear Engineering Services
*J. Hinds, Director, Nuclear Safety Engineering
*K. Hubbard, Senior Engineer, Regulatory Compliance
M. Mayer, Reactor Engineer
*W. McLane, Director, Training
*J. Molden, Director, Instrumentation and Controls
*T. Moulia, Assistant to the Vice President
*T. Rapp, Chairman, On-Site Safety Review Group
*P. Sarafian, Senior Engineer, Onsite Review Group
J. Skaggs, Supervisor, Operations
M. Stephen, Senior Engineer, Nuclear Excellence Team
D. Stermer, Engineer, Systems Engineering
*D. Taggart, Director, Onsite Quality Assurance

*Denotes those attending the NRC exit interviews on May 7 or May 26, 1993.

The inspectors interviewed other licensee employees including shift supervisors, shift foremen, reactor and auxiliary operators, maintenance personnel, plant technicians and engineers, and quality assurance personnel.

2. Operational Status of Diablo Canyon Units 1 and 2

Unit 1 operated at 100% power for the entire report period.

Unit 2 completed its fifth refueling outage during this inspection period and achieved criticality on May 2, 1993. Power was gradually increased,

reaching 100% on May 10, and remained there until the end of the inspection period.

3. Operational Safety Verification (71707)

a. General

During the inspection period, the inspectors observed and examined activities to verify the operational safety of the licensee's facility. The observations and examinations of those activities were conducted on a daily, weekly or monthly basis.

On a daily basis, the inspectors observed control room activities to verify compliance with selected Limiting Conditions for Operation (LCOs) as prescribed in the facility Technical Specifications (TS). Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions and to evaluate trends. This operational information was then evaluated to determine whether regulatory requirements were satisfied. Shift turnovers were observed on a sampling basis to verify that all pertinent information on plant status was relayed to the oncoming crew. During each week, the inspectors toured accessible areas of the facility to observe the following:

(1) General plant and equipment conditions

(2) Fire hazards and fire fighting equipment

(3) Conduct of selected activities for compliance with the licensee's administrative controls and approved procedures

(4) Interiors of electrical and control panels

(5) Plant housekeeping and cleanliness

(6) Engineered safety features equipment alignment and conditions

(7) Storage of pressurized gas bottles

The inspectors talked with control room operators and other plant personnel. The discussions centered on pertinent topics of general plant conditions, procedures, security, training, and other aspects of the work activities.

On May 5, 1993, the inspectors conducted a tour of the Units 1 and 2 auxiliary building and emergency diesel generator areas. The inspectors observed two situations warranting followup. First, painters were painting in the Unit 2 Class-1E battery rooms and the inspectors observed that no supervision was in the area; the painters had placed a metal tape measure on the battery near the terminals, and had placed a plastic hard hat between the negative and positive terminals. In addition, one painter was working in the restricted space between the battery and the wall and was leaning in such a position that his back was touching the terminals of the

battery. While this did not cause an electrical hazard concern, a hazard could have resulted if a ground had existed on the system. The inspectors discussed this concern with licensee management, who effected corrective action.

In addition, the inspectors observed that the radiator for the emergency diesel generator 2-3 engine was partially clogged with dirt and debris. This was discussed with licensee management, who observed that the jacket water temperature was within specification during the last monthly test of the emergency diesel generator, the radiator is cleaned by a preventive maintenance procedure every nine months, and the radiator for emergency diesel generator 2-3 was designed with an oversized cooling capacity. The inspectors had no further questions.

b. Radiological Protection

The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors verified that health physics supervisors and professionals conducted frequent plant tours to observe activities in progress and were aware of significant plant activities, particularly those related to radiological conditions and/or challenges. ALARA considerations were found to be an integral part of each RWP (Radiation Work Permit).

c. Physical Security

Security activities were observed for conformance with regulatory requirements, implementation of the site security plan, and administrative procedures, including vehicle and personnel access screening, personnel badging, site security force manning, compensatory measures, and protected and vital area integrity. Exterior lighting was checked during backshift inspections.

No violations or deviations were identified.

4. Onsite Event Follow-up (93702)

a. Inadvertent Dilution of Reactor Coolant System

During the shutdown risk team inspection in 1992, the team identified to the licensee the specific need for controls to preclude inadvertent dilution of boron in the spent fuel pool and the refueling cavity. The licensee issued a new procedure and installed metering devices to monitor the water inventory additions. In this case, the boron concentration was verified to be within limits.

On April 5, 1993, during the Unit 2 outage, Operations personnel returned mixed bed demineralizer 2-2 to service without consulting chemistry staff personnel, and induced a change of 24 ppm boron concentration in the refueling cavity. Following a resin bed replacement, the bed had been rinsed but not borated, and two

administrative clearance tags had been affixed to the demineralizer. The clearance tags were temporarily removed during fill and vent of the chemical and volume control system (CVCS), and were not returned to the mixed bed demineralizer. The reactivity change was identified, but the event was not promptly elevated in the quality evaluation system. Even though the licensee concluded that the change in boron concentration was small (24 ppm), and there was a margin of greater than 290 ppm before reaching the lower boron concentration limit of 2100 ppm, the inspector was concerned that the licensee did not initiate a root cause analysis, quality evaluation, nonconformance report, or corrective actions after the April 5 event.

A second dilution event occurred in Unit 2 on May 12, 1993, with the unit at 100% power. In this case, operators returned a cation ion exchanger to service, and the dilution apparently resulted from the injection of approximately 200 gallons of water, with low boron concentration, which had been in the associated piping. A reactor power excursion of 0.7% occurred, which was mitigated promptly by operator corrective action. The licensee estimated that, without operator action, the power excursion would have been approximately 3% and might have resulted in a turbine runback.

The inspector was concerned that the procedures and tag-out program did not appear to have been adequate to prevent these inadvertent boron dilutions when the demineralizer and cation ion exchanger were placed into service. This issue will be examined further during the next inspection (Unresolved Item 50-323/93-12-01).

b. <u>Water Inventory in Unit 2 Reactor Coolant Pump Oil Spill Collection Tank from Unidentified Source</u>

The licensee's fire protection program and Section III.O of Appendix R to 10 CFR Part 50 require a reactor coolant pump (RCP) lube oil spill collection system. Each unit has a 300-gallon RCP lube oil spill collection tank inside containment to hold the lube oil inventory of one RCP, with a 35-gallon margin. Auxiliary operator (AO) log sheets indicate that a level of less than two inches should be maintained in the tank. The tank is drained to the structure sump in the containment.

On May 5, 1993, while the reactor was at approximately 50% power, the licensee noted that the level in the Unit 2 RCP lube oil spill collection tank was at two to three inches. During a containment entry on May 10, 1993, the level was noted to be approximately 15 to 16 inches with a liquid inventory in the tank of approximately 120 gallons of water. A sample of the water was found to contain about 4000 ppm of boron, with detectable short- and long-lived isotopes. Although the boron concentration in the primary coolant was 1000 ppm, it had been greater than 2100 ppm during the recent shutdown. The reactor coolant system leakage, as determined by surveillance test procedure (STP R-10C), was approximately 0.1 gallons per minute during the May 5-10 interval. The licensee had not determined the source of water.

On May 12, after chemistry personnel determined that there was no indication of further leakage, the licensee drained the water in the tank to less than 0.5 inches and initiated action to monitor the level approximately every two weeks. There had been no further increase in tank level as of June 8, 1993, and the Operations Department was continuing to monitor tank level during the regular bi-weekly walkdown.

The licensee reviewed the geometry of the tank and the overflow line, and determined that the presence of the water inventory in the tank did not appear to reduce the capability of the tank, with allowance for overflow, to receive all the lube oil from one RCP. This was consistent with the licensee's NRC-approved fire protection program, and therefore did not appear to violate the 10 CFR 50, Appendix R requirements. The inspector concluded that the licensee's evaluation and bi-weekly monitoring of the tank level were appropriate.

c. Condenser Air Ejector Discharge Radiation Alarms

At 12:42 a.m. on April 30, 1993, the Unit 1 condenser air ejector discharge radiation monitors RM-15 and RM-15R alarmed high with a peak reading of approximately 26,000 counts per minute. The licensee indicated that the setpoint for the radiation monitors was 370 counts per minute. Both monitors detected the activity at the same time. The condenser off-gas flow indicated a momentary increase, coincident with the alarms. The initial air ejector noble gas sample taken at 1:05 a.m. showed traces of Xenon-133, corresponding to a primary-to-secondary leak rate of about 1.81 gallons per day, as documented in Action Request No. A0305765. Backup air ejector samples of noble gas at 1:30 a.m. and 1:45 a.m. showed no detectable gamma activity. On the same day, the licensee installed a resin column on each of the steam generator blowdown line for three days. No detectable activity was recorded. Subsequently, the licensee installed a resin column on each of the blowdown lines for seven days to increase the sensitivity of detection. Again, no detectable activity was recorded.

The licensee concluded that the coincidence of the two alarms, the off-gas flow increase, and the activity detected during the initial sampling indicated this not to be a false reading. A primary-to-secondary leak apparently existed for about six minutes at a leak rate of approximately two gallons per minute. The radioactivity levels then returned to normal background after thirty minutes. There was no recurrence before the end of the inspection period.

The licensee also indicated that the operators were refreshed on steam generator tube rupture procedures and that all shift personnel were aware of the alarms which had been received. During previous observations at the simulator, the inspectors had observed that operators were trained and able to isolate primary-to-secondary leaks quickly, often within seconds. The licensee's operator training, and the heightened awareness of a potential primary-to-secondary leak appeared appropriate.

d. Corrosion of Unit 2 Reactor Coolant Pump (RCP) Seal Injection Valves Due to Improper Materials

During a routine pre-outage diagnostic inspection, the licensee determined that the disk of an RCP seal injection valve had separated from the stem. Licensee inspection of all four valves in Unit 2 found that the disks of two of the one-inch "T" type valves were made from carbon steel instead of stainless steel as specified. The improper material had corroded, resulting in separation of the disk from the stem. The valve failed in the normal operation position of open, which is the same as the accident position. In September 1992, similar pre-outage diagnostic testing was performed in Unit 1, with no adverse findings.

The licensee stated that the valves were supplied as Rockwell Model 3724F316J (Westinghouse-1-X58N) to Westinghouse, who supplied the valves as Class-1 valves to the licensee. Rockwell-Edwards has also manufactured similarly designed 3/4" and 2" valves. The licensee conducted searches and consulted Westinghouse, and found no history of failure of these valves in the industry. Based on investigation, the licensee believed that the improper material was limited to the those valves designated as Rockwell 1"-X58N.

The licensee determined that valves of this type were used as Unit 1 RCP seal injection valves and in both units as a normally open isolation valve for a pressure instrument which monitors charging injection header pressure to minimize thermal cycling of charging injection nozzles. The licensee performed an operability evaluation, OE No. 93-06R0, which concluded that the potential failure of other valves of this type did not involve a safety concern. The OE noted that a redundant pressure instrument would be used if the pressure instrument valve failed in the closed position, and that existing monthly surveillance tests and alarm setpoints would be adequate to ensure proper flow through the RCP seal valves. The licensee stated that introduction of loose material (due to valve disk corrosion) into the flow stream (and potentially across the RCP seal surfaces) might occur, but was not a concern.

The licensee replaced all of the Unit 2 RCP seal injection valves with new valves of an appropriate material, and plans to replace all of the Unit 1 valves no later than the next scheduled refueling outage.

No violations or deviations were identified.

5. Containment Fan Cooler Unit Backdraft Damper Counterweights (93702)

NRC Inspection Reports 92-05, 92-16, and 92-17 discussed failures of containment fan cooler unit (CFCU) backdraft damper assemblies. The root cause of the concern was improper maintenance and assembly. A contributing cause was determined to have been high levels of vibration in CFCUs and in ventilation ducting. The issue of improper CFCU maintenance and assembly was closed.

On May 5, 1993, the licensee identified that a set of two backdraft damper counterweights from Unit 2 CFCU 2-1 had become detached from the damper, and fallen to the deck below. The licensee initiated an investigation. On May 6, the remaining Unit 2 backdraft dampers were inspected and found to be intact. On May 13, CFCUs in Unit 1 were inspected and one counterweight from CFCU 1-2 was found detached from the damper. All CFCU backdraft dampers were verified to have been installed in accordance with vendor and licensee required procedures. Significant vibration was observed in some parts of the dampers. A preliminary root cause was that the nuts backed off the threaded fasteners which secured the counterweights. The licensee reattached the counterweights and staked all counterweight fastener threads on all CFCUs to ensure that no additional nuts would back off. Further design reviews of the dampers, fasteners, and CFCU ventilation system, as well as discussions with the vendor, are ongoing.

In Action Request A0306360 and Quality Evaluation Q0010666, the licensee documented conclusions that the as-found condition and as-repaired condition of the CFCUs were not safety significant, based on previous operability evaluations and operating experience documented in A0256600. These concluded that, since the dampers are linked, the lack of one set of counterweights would not prevent dampers from closing.

The NRC will follow the licensee's actions as more information becomes available. The safety significance of the specific issue at this time appears low based on the above licensee conclusions, corrective actions, continuing investigative efforts, and on earlier analysis results which concluded that operation of only 2 CFCUs was required to mitigate a design basis event. Further followup of the licensee's evaluation of the adequacy of the CFCU system design will be performed as part of routine resident inspections.

No violations or deviations were identified.

6. Restart from Refueling (71711)

The inspectors observed the approach to criticality and the testing at different stages of power ascension. The Operations staff appeared to have appropriately and conservatively monitored plant conditions and followed plant procedures. Test results were also observed to satisfy acceptance criteria. In particular, the inspectors reviewed the following surveillances:

a. Moderator Temperature Coefficient (61708)

The inspectors reviewed the process used to determine the moderator temperature coefficient. Surveillance procedure STP R-7A, "Determination of Moderator Temperature Coefficient at HPZ, BOL," Revision 8, was used by Plant Operations on April 30, 1993. The procedure appeared to be clear, and provided a satisfactory method of MTC determination. Licensed operators appeared to have followed the procedure appropriately in the determination of moderator temperature coefficient.

b. Shutdown Margin (61707)

To evaluate preparations for startup, the inspectors observed the performance of surveillance test procedure STP R-19, "Shutdown Margin Determination," Revision 11. The procedure appeared clear and appropriate for determination of the reactivity balance and existing shutdown margin for the core. Operators followed the procedure without difficulty, and appeared to have a clear understanding of the purposes of the procedure steps.

c. Rod Worth (61710)

The inspectors observed Operations and Reactor Engineering staff personnel perform surveillance test procedure STP R-31, "Rod Worth Measurements Using Rod Swap Method," Revision 3, in preparation for Unit 2 startup after the refueling outage. Efforts appeared to have been well coordinated between the two departments, and the procedure was followed without difficulty. Although a comparatively high volume of data was recorded, data sheets were logically arranged, allowing calculations to be executed easily. Acceptance criteria and tolerances were clearly stated.

No violations or deviations were identified.

7. Engineering Activities

a. Core Reload Design (37700)

The licensee controlled core reload design as a design change using their design change program. This program assured that the appropriate reviews were accomplished and documented. The licensee contracted with Westinghouse to provide fuel and reload core design (reload pattern, critical boron concentration for all rods out, moderator temperature coefficient, doppler coefficient, and other design parameters).

The licensee verified core performance at initial criticality, and during power ascension by verifying the Westinghouse design parameters were within certain acceptance criteria. Core performance was verified monthly during operation by use of flux mapping. Flux map information was reviewed by corporate office engineers using the PG&E computer system and codes. PG&E computer codes were used to monitor core performance monthly. The flux map information was provided to Westinghouse quarterly for performance verification using NRC approved computer codes.

Engineers at the corporate office provided the site with the Westinghouse final core reload pattern, the reload safety evaluation, and a copy of the approved Westinghouse reload analysis. The site then determined the sequence of operations necessary to achieve the approved reload pattern. The reload pattern was verified when completed by mapping the core to verify that all fuel assemblies were in the correct location.

The inspector concluded that the licensee's program for reviewing and approving core reload design information appeared appropriate.

b. Design Criteria Memoranda (DCM) (37700)

The inspector discussed the use of the Design Criteria Memoranda (Design Basis Documents) with site representatives from the training, Systems Engineering, and Operations Engineering organizations. The training organization appeared to be reviewing the DCMs as they are received and revising lesson plans, as necessary, to assure that training materials are accurate. Systems engineers receive and used the DCMs for their systems as the DCMs are issued. The licensee's system engineers assure that plant procedures consistently reflect DCM information; however, this is not formally required by administrative control procedures. The licensee is in the process of providing interface and administrative controls by means of interdepartment administrative procedures. This would assure that DCMs are examined for consistency with maintenance, surveillance, and operating procedures, as necessary.

The inspector reviewed the status of DCM completion and also observed that the licensee had completed DCMs for the nuclear safety related systems (as well as most other systems), and was making good progress on their schedule.

No violations or deviations were identified.

8. Quality Oversight Organizations (40500)

This inspection included a review of recent licensee activities to restructure the quality oversight organization, and an examination of the performance of various oversight groups.

a. Reorganization of Quality Oversight Organization

The licensee initiated a program in 1992 to evaluate their quality oversight organizations and efforts. The objectives of the program were to: (1) identify strengths and potential improvements in the performance of QA/QC activities; (2) identify duplication between QA, QC and other oversight activities; and (3) develop recommendations for improving the effectiveness and efficiency of QA and QC activities.

The licensee formed a project team, developed a project plan, prepared oversight and responsibility charts, collected data, analyzed the data and developed recommendations. The significant recommendations included, among others, that the licensee: (1) bring QA/QC and other oversight activities together into a single nuclear oversight department; (2) eliminate duplication of effort; (3) increase QA/QC time in the field; (4) locate as many as possible of the QA and other oversight groups at the site; and (5) enhance trending programs for and analysis of quality problem reports. The licensee was in the process of implementing the recommendations. In addition, the licensee was in the early phases of consolidating all

quality and oversight organizations into a single organization called Nuclear Quality Services; a new manager had recently been appointed.

The inspectors questioned the licensee regarding plans for assessing the effectiveness of the reorganization and was informed that this question was being considered regarding the method and timing of an effectiveness assessment.

b. Onsite Safety Review Group (OSRG) (40500)

The OSRG performs the function of the Independent Safety Engineering Group at Diablo Canyon. Technical Specification 6.2.3 details the function and composition of the OSRG; administrative controls are implemented by procedure NSARA-6.1 (OSRG Organization and Responsibilities).

The inspectors reviewed five OSRG monthly reports. The reports were thorough, in-depth reviews of a variety of functional areas. Findings and recommendations were valid and substantial. Generally, the problems found by the OSRG were documented using the licensee's Action Request system and tracked to closure using that system. However, the inspector observed one OSRG conclusion regarding ineffective corrective action which was not documented in the licensee's problem reporting system. The inspector discussed this situation with licensee management, including the newly named manager of the Nuclear Quality Services organization. The licensee representatives indicated that they recognized the potential that OSRG general conclusions of problems, not documented in the problem reporting systems, may be inadvertently overlooked by site management. The licensee indicated that the potential for overlooking general conclusions would be addressed by the new Nuclear Quality Services organization and corrected.

The OSRG reports were submitted to senior management in the San Francisco General Office and copied to management at the site. The newly appointed manager of the Nuclear Oversight organization indicated the intent to assure that OSRG reports and findings were reviewed by on-site management, and to assure that all problem situations were documented and resolved by the established problem reporting systems.

The inspectors observed that the OSRG frequently made recommendations regarding corrective actions for problems observed. The inspector noted that if an oversight organization becomes a party by specifying and effecting corrective action for the problems identified, that organization may lose the degree of independence and objectivity necessary to perform meaningful assessments of corrective action effectiveness. The licensee acknowledged the inspector's concern as one they were considering and would be careful to avoid in the corrective action process.

The inspectors examined the resumes of experience and education for the OSRG members. All were degreed engineers with sufficient

experience in plant operations and engineering to qualify them to perform meaningful, independent assessments and provide valid recommendations to senior management.

c. Nuclear Safety Oversight Committee (NSOC) (40500)

The licensee was in the process of establishing a Nuclear Safety Oversight Committee which would replace the General Office Nuclear Plant Review and Audit Committee (GONPRAC). The licensee had established an NSOC charter and was in the process of establishing a revision to the GONPRAC Procedure (NPG-2.8) which would provide administrative controls to implement the charter.

The inspectors reviewed the NSOC charter and concluded that the charter appeared adequate for the purposes of the NSOC. Additionally, the inspector sampled and reviewed certain NSOC minutes and concluded that the NSOC was accomplishing the charter requirements.

d. Nuclear Excellence Team (NET) (40500)

The licensee formed this arm of nuclear oversight during 1990, and a procedure for their activities was approved in June 1991 (Procedure NOS-3.7.1, "Nuclear Excellence Team Organization and Responsibilities"). The mission of the NET is to provide performance-based self-assessment of Diablo Canyon programs and organizations to improve plant performance. The NET compared nuclear industry standards of excellence with Diablo Canyon activities to maintain Diablo Canyon programs and performance at a high level.

The NET is currently located at the San Francisco General Office, but plans to relocate to the Diablo Canyon site with the newly formed Nuclear Safety Engineering organization. The NET has been performing 3-5 assessments per year using a team comprised of senior engineers from several plant organizations (e.g., maintenance, operations, engineering, radiation protection and chemistry), as well as industry counterpart experts.

The NET had performed a number of assessments, resulting in several improvement recommendations (e.g., Fire Protection/Appendix R, Outage Risk Management, and NPG INPO-style self-assessments). The inspectors examined these assessments and concluded that they were substantial efforts and improvements.

e. Quality Performance and Assessment (40500)

The inspectors examined the work products of the of the Quality Performance and Assessment organization by reviewing several audits and surveillance reports and reviewing the 1993 first quarter report to the Manager of Quality Assurance. The audits and surveillances successfully identified several significant problems, and findings were tracked to closure.

The inspector examined the problem trending system and found that the system appeared fragmented and that trend reports did not focus on the performance of organizations, equipment or activities. Further, the inspector found that the quality trending program did not capture all trending programs used onsite (e.g., equipment trends, EQ trends, and fire protection). In addition, not all problems from the Action Request reporting system were captured by the trending program. The licensee recognized the limitations of the trending program and was assessing actions to make the program more useful and focused.

No violations or deviations were identified.

9. Engineered Safety Feature Verification (71710)

During this inspection period, the inspectors performed a review and a walkdown of the internal hydrogen recombiner system inside Unit 2 containment, and the associated control and power cabinets in the switchgear areas to verify that system configuration, equipment condition, electrical lineups, and local breaker positions were in accordance with plant drawings and Technical Specifications. In addition, the inspectors also walked down the backup hydrogen purge system, a non-safety system, and the connection piping to the external hydrogen recombiner in Units 1 and 2.

System Requirements

The two internal hydrogen recombiners inside containment are the primary means of post-accident combustible gas control. These two redundant recombiners and their associated control and power connections are safety related. The hydrogen purge system is a non-safety-related system. The licensee stated that Diablo Canyon Power Plant also has a regulatory commitment to be capable of connecting an external hydrogen recombiner.

The inspectors reviewed emergency operating procedure (EOP) E-1, "Loss of Reactor or Secondary Coolant," Revision 9. The EOP required the internal hydrogen recombiners to be put into operation if, less than 28 days after a loss of coolant accident (LOCA), the containment hydrogen concentration is between 0.5% and 3.5%. The EOP also required the hydrogen purge system to be put into operation if, more than 28 days after a LOCA, the containment hydrogen concentration is between 0.5% and 3.5%.

System Verification

The inspectors performed a system walkdown and a review of the surveillance procedures for the internal hydrogen recombiner system. The system and associated surveillances and preventive maintenance procedures appeared to be adequate to ensure that hydrogen concentration was controlled during accidents. The inspectors noted that, contrary to the typical engineering support provided for engineered safety features, the licensee viewed the hydrogen recombiners and the associated control and power circuits as components rather than as a system. The licensee had, therefore, not assigned a system engineer to the hydrogen recombiner system.

In addition, the inspectors also walked down the hydrogen purge system (the non-safety backup to the hydrogen recombiners) and the connections to the external hydrogen recombiners. The inspectors identified the following discrepancies associated with the hydrogen purge system and with the piping connections to the external hydrogen recombiners:

- The design drawings did not reflect the as-built conditions, in that blind flange connections were missing, and piping connections were misrepresented.

- The inspectors also identified a mislabelled containment penetration number and a missing valve label.

- The dose exposure to personnel required to put the hydrogen purge system into operation was unknown. Manual pump and valve operations are necessary to put the purge system into operation.

Other than the above discrepancies, the hydrogen purge system appeared to have been properly configured and related administrative controls appeared appropriate.

The licensee acknowledged the inspectors' findings and discussed corrective actions with the inspectors. The resolution of these issues will be examined during a future inspection (Followup Item 50-275/93-12-02).

No violations or deviations were identified.

10. Maintenance (62703)

The inspectors observed portions of, and reviewed records on, selected maintenance activities to assure compliance with approved procedures, Technical Specifications, and appropriate industry codes and standards. Furthermore, the inspectors verified that maintenance activities were performed by qualified personnel, in accordance with fire protection and housekeeping controls, and that replacement parts were appropriately certified. These activities included:

- Work Order C0108903, Inspect, Clean and Retorque Safety Injection Pump Casing Bolts

- Work Order R0086777, Routine Preventive Maintenance of Hydrogen Recombiners

- Work Order R0094642, Removal of Foreign Material Covers From the Unit 2 ECCS Recirculation Sump

- Work Order C0114187, CCW-2-459, RHR Heat Exchanger Outlet Valve, Disassemble And Repair

- Work Order C0114724, VAC-1-BD-43, CFCU 1-1, Stake Counterweight Bolt Threads

- Work Order C0114725, VAC-1-BD-44, CFCU 1-2, Install Counterweight and Stake All Backdraft Damper Counterweight Bolt Threads

- Work Order C0113514, LT-461, Pressurizer Level Transmitter, Provide Support to I&C for Freeze Seal on Instrument Tubing

- Work Order C0113873, CVCS-2-8369C, RCP 2-3 Seal Injection Valve, Replace Valve

- Work Order C0114667, PT-405, Pressurizer Pressure Transmitter, Troubleshoot and Correct Erratic Signal

- Work Order C0114640, RCP Lube Oil Collection Tank, Support Chemistry and Radiation Protection, Pump Down Tank

- Work Order C0114427, IY-13A, Vital Inverter, Investigate and Correct Failure

No violations or deviations were identified.

11. Surveillance (61726)

By direct observation and record review of selected surveillance testing, the inspectors checked compliance with TS requirements and plant procedures. The inspectors verified that test equipment was calibrated, and that test results met acceptance criteria or were appropriately dispositioned. These tests included:

- STP M-45A, Containment Inspection Prior to Establishing Containment Integrity, and Inspection of Residual Heat Removal Containment Recirculation Sump

- STP M-45C, Outage Management Containment Inspection

- STP M-88C, Channel Calibration of Internal Hydrogen Recombiner Power Meter, Heater Inspection and Heatup Test

- STP M-88A, Electrical Hydrogen Recombiner Functional Test

- STP M-88B, Calibration of Temperature Indicators For Electric Hydrogen Recombiners

- STP M-9A, Diesel Engine Generator Routine Surveillance Test

No violations or deviations were identified.

12. Followup of Open Items (92701)

Incorrect Dowel Dimension in Safety Related Check Valves (Followup Item 50-323/93-07-04, Open)

The inspection included a review of the licensee's actions involving the reportability of deficiencies found in both 4-inch and 8-inch check valves installed in safety-related systems. 10 CFR Part 21 requires the reporting of defects in basic components that could create a "substantial safety hazard." However, 10 CFR 21.2 relieves the holders of operating licenses from the Part 21 evaluation, notification, and reporting

requirements since the appropriate reporting of defects will be accomplished pursuant to either 10 CFR 50.72, 50.73, or 73.71. Therefore, for operating plant equipment, if the reporting requirements of 10 CFR 50.72 and 50.73 are followed, the holder of a power plant operating license has no other responsibility under 10 CFR 21 to report defects in installed equipment components. Based on the above information a 10 CFR 21 report is not required for the check valve deficiencies. It should be noted that the licensee committed to submit an LER per 10 CFR 50.73 which addresses the issue. This item remains open pending review of the LER and other issues discussed in Inspection Report No. 93-07.

No violations or deviations were noted.

13. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable items, violations, or deviations. An unresolved item addressed during this inspection is discussed in paragraph 4.a of this report.

14. Exit Meeting

The inspectors conducted exit meetings on May 7 and May 26, 1993, with the licensee representatives identified in Paragraph 1. The inspectors summarized the scope and findings of the inspection as described in this report. The licensee representatives acknowledged the inspectors' findings and comments.

The licensee did not identify as proprietary any of the materials reviewed by or discussed with the inspectors during this inspection.