50-275/323-OLA-2 I-MFP-105 MFP Exhibit 105
8/21/93 8/21/93 Dollie Feigel
Repte

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION V

1450 MARIA LANE
WALNUT CREEK, CALIFORNIA 94596-5368 '93 OCT 28 P6:17

December 11, 1992

Pacific Gas and Electric Company
Nuclear Power Generation, B14A
77 Beale Street, Room 1451
P. O. Box 770000
San Francisco, California 94177

Attention: Mr. G. M. Rueger, Senior Vice President and General Manager
Nuclear Power Generation Business Unit

Subject: NOTICE OF VIOLATION
NRC INSPECTION REPORT NOS. 50-275/92-31 AND 50-323/92-31

This refers to the routine inspection conducted by D. Corporandy, J. Melfi, M. Miller, C. Myers, and B. Olson during the period from September 29 through November 9, 1992. This inspection examined your activities as authorized by NRC License Nos. DPR-80 and DPR-82. At the conclusion of the inspection, the inspectors discussed their findings with members of the PG&E staff.

Areas examined during this inspection are described in the enclosed inspection report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observations by the inspectors.

Based on the results of this inspection, it appears that certain of your activities were not conducted in full compliance with NRC requirements, as set forth in the enclosed Notice of Violation (Notice), and in the enclosed inspection report (Paragraph 6). In October 1991, at the close of the Unit 2 outage, you correctly identified and reported an inadequate program to control loose material in the Unit 2 containment. However, NRC inspectors identified similar materials in the Unit 1 containment at the close of the October 1992 outage, indicating that your corrective actions had not addressed this weakness in a sufficiently comprehensive manner. Before completion of this inspection, the inspectors confirmed that your organization has taken or initiated corrective actions which satisfactorily address this concern before the next scheduled outage. Consequently, a written response to the enclosed Notice is not required.

A non-cited violation was also noted, involving documentation and periodic verification of jumpers, as discussed in Paragraph 13 of the enclosed report. Since the criteria of the NRC Enforcement Policy were satisfied, this violation was not cited.

An area of noteworthy strength was identified. Concerning outage safety, your Unit 1 shutdown safety requirements appeared to have been well developed and implemented. Operations and outage management appeared to have maintained a very high level of safety system availability and configuration control during the outage. You are encouraged to maintain this high level of safety.

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NUCLEAR REGULATORY COMMISSION

Docket No. 50-275-OLA Official Exh. No. TTFP-105
In the matter of PACIFIC GAS and ELECTRIC Co

Staff ____________ IDENTIFIED ✓
Applicant ____________ RECEIVED ✓
Intervenor ✓ ____________ REJECTED ____________
Cont'g Off'r ____________
Contractor Ann Riley & Assoc's DATE 8-21-93
Other ____________ Witness ____________
Reporter Dollie Feigel

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In accordance with 10 CFR 2.790(a), a copy of this letter and the enclosures will placed in the NRC Public Document Room.

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

S. A. Richards, Acting Chief
Reactor Projects Branch

Enclosures:
1. Notice of Violation
2. Inspection Report Nos. 50-275/92-31 and 50-323/92-31

cc w/enclosures:
J. A. Sexton, PG&E
C. J. Warner, PG&E
J. D. Townsend, PG&E (Diablo Canyon)
D. A. Taggart, PG&E (Diablo Canyon)
T. L. Grebel, PG&E (Diablo Canyon)
C. B. Thomas, News Services, PG&E
State of California
R. Hendrix, County Administrator
Sandy Silver

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APPENDIX A

NOTICE OF VIOLATION

Pacific Gas and Electric Company
Diablo Canyon Nuclear Plant, Unit 1

Docket No. 50-275
License No. DPR-80

During an NRC inspection conducted from September 29 through November 9, 1992, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C, the violation is listed below:

A. 10 CFR Part 50, Appendix B, Criterion XVI, states in part that:

Measures shall be established to assure that conditions adverse to quality ... are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the conditions is determined and corrective action taken to preclude repetition.

Contrary to the above, corrective actions described in Licensee Event Report No. 50-323/91-12 to prevent uncontrolled materials inside the containment when containment integrity has been established were not sufficient to prevent recurrence. On November 5, 1992, with containment integrity established in Unit 1, loose, unattended materials were observed near the containment sump.

This is a Severity Level IV violation (Supplement I), applicable to Unit 1.

Based on the corrective actions taken or initiated by the licensee, no response to this violation is required.

Dated at Walnut Creek, California
this 11th day of December, 1992

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U.S. NUCLEAR REGULATORY COMMISSION
REGION V

Report Nos:	50-275/92-31 and 50-323/92-31
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:	September 29 through November 9, 1992
Inspectors:	M. Miller, Acting Senior Resident Inspector B. Olson, Resident Inspector D. Corporandy, Project Inspector J. Melfi, Resident Inspector, Trojan C. Myers, Reactor Inspector (Paragraph 15)
Approved by:	P. Johnson, Chief Reactor Projects Section 1 — 12/11/92 Date Signed

Summary:

Inspection from September 29 through November 9, 1992 (Report Nos. 50-275/92-31 and 50-323/92-31)

Areas Inspected: The inspection included routine inspections of plant operations; maintenance and surveillance activities; followup of onsite events, open items, and licensee event reports (LERs); and selected independent inspection activities. Inspection Procedures TI 2515/20, 37700, 41701, 61726, 62703, 71500, 71707, 71710, 90712, 92700, 92701, and 93702 were used as guidance during this inspection.

Safety Issues Management System (SIMS) Items: TI 2515/20, inspection of Anticipated Transient Without Scram (ATWS) system, was closed for Unit 1.

Results

General Conclusions on Strengths and Weaknesses

Strengths:

Operations and outage management maintained a high level of awareness and control of safety system availability during the Unit 1 outage.

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Weaknesses were identified in:

- Containment cleanliness at the close of the Unit 1 outage, as well as failure to fully correct the weakness identified in the earlier Unit 2 outage (Paragraph 6).

- Lack of a drainage path from relief valve tailpipes which could collect condensation (Paragraph 12).

- Lack of attention to detail in periodic walkdown and review of plant temporary jumper logs (Paragraph 13).

Significant Safety Matters:

None

Summary of Violations:

- A violation was identified involving inadequate corrective actions to ensure containment cleanliness while in Mode 4 after an outage (Paragraph 6).

- A non-cited violation was identified, involving failure to follow procedures concerning periodic walkdowns and reviews of jumpers (Paragraph 13).

Open Items Summary:

One item was opened and 15 items were closed.

DETAILS

1. Persons Contacted

Pacific Gas and Electric Company

G. M. Rueger, Senior Vice President and General Manager, Nuclear Power Generation Business Unit
*J. D. Townsend, Vice President and Plant Manager, Diablo Canyon Operations
W. H. Fujimoto, Vice President, Nuclear Technical Services
*D. B. Miklush, Manager, Operations Services
*B. W. Giffin, Manager, Maintenance Services
W. G. Crockett, Manager, Technical Services
J. E. Molden, Instrumentation and Controls Director
W. D. Barkhuff, Quality Control Director
*R. P. Powers, Manager, Support Services
T. L. Grebel, Regulatory Compliance Supervisor
*J. S. Bard, Mechanical Maintenance Director
H. J. Phillips, Electrical Maintenance Director
J. A. Shoulders, Onsite Project Engineer
*D. A. Taggart, Director, Quality Performance and Administration
*S. R. Fridley, Operations Director
T. A. Moulia, Assistant to Vice President, Diablo Canyon Operations
M. R. Tresler, Project Engineer
*D. A. Moon, Regulatory Compliance Engineer
*R. L. Thierry, Regulatory Compliance Senior Engineer
*L. R. Collins, Senior Quality Assurance Supervisor
*D. R. Lampert, Outage Management Coordinator
*W. P. McLane, Outage Director
*M. O. Sommerville, Senior Health Physics Engineer
*J. J. Griffin, Onsite Engineering Group Leader
*C. R. Groff, Technical Services Assistant Manager
*J. E. Fields, Quality Control (QC) Lead Engineer
*W. T. Rapp, Onsite Safety Review Group Chairman
*M. Burgess, System Engineering Director

*Denotes those attending the exit interview.

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

During this inspection period, Unit 1 completed its fifth refueling outage and achieved criticality on the last day of the inspection period.

Unit 2 operated at 100% power for the entire report 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.

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.

d. Safety System Availability During Unit 1 Outage

During the Unit 1 refueling outage, the inspectors observed that the licensee's program to control the availability of safety systems appeared to be highly effective. The availability of safety systems such as emergency diesel generators, the auxiliary saltwater system, and other safety significant systems was well coordinated and controlled. This control appeared to have assured that the maximum number of redundant systems were available while work was done on the remaining systems. Also, a high level of plant staff awareness and system availability were maintained during higher risk operations, such as mid-loop operations. An NRC team inspection of outage safety control was also conducted, as discussed in pending NRC Special Inspection Branch Inspection Report No. 50-275/92-201.

No violations or deviations were identified.

4. Onsite Event Follow-up (93702)

a. Cracking of Containment Fan Cooler Unit (CFCU) Backdraft Damper Blades

Summary:

During the Unit 1 outage, the licensee identified that cracking had occurred in some of the blades of the Unit 1 CFCU backdraft dampers. The licensee assessed the safety significance of the cracking, developed an operability assessment for Unit 2, and performed visual inspections of the Unit 2 backdraft damper blades (Unit 2 was operating). The licensee identified two cracked blades in Unit 2. The cracked blades which had been identified were removed from Unit 2 on November 10, 1992.

Time Line:

9/25/92 Three cracked blades were identified in Unit 1 CFCU dampers during outage work.

10/10/92 An additional crack was identified by use of magnetic particle examination.

10/13/92 Analysis and testing concluded that the cracks could lead to blade failure during a design basis LOCA.

10/14/92 Prompt operability assessment (POA) concluded that the Unit 2 CFCUs were operable. This was partially based on expected confirmation that the Unit 2 blades were in a condition similar to or better than Unit 1.

10/15/92 Licensee implemented Event Response Plan ERP 92-9 to address the CFCU blade issue.

10/18/92 Unit 2 CFCUs were inspected. Two blades were identified to have cracks.

10/26/92 Operability Evaluation (OE) 92-20R0 was issued.

10/30/92 On Site Safety Review Group (OSRG) and Plant Safety Review Committee (PSRC) identified several concerns with OE 92-20R0. The licensee planned to revise the OE.

11/10/92 The 2 cracked damper blades in Unit 2 CFCUs were removed.

Operability Evaluation

On October 14, 1992, the licensee prepared a prompt operability assessment (POA) which preliminarily concluded that CFCUs were operable although damper blades could break during a post-LOCA pressure wave and be blown up into the fan volute. This conclusion of operability was based on the low fraction of damper blades expected to enter the path of the fan blades, and the low probability of significant damage to the fan if a damper blade did come in contact with a fan blade.

On October 26, 1992, the licensee issue OE 92-20R0 which concluded that Unit 2 CFCUs were operable with cracked damper blades at least until November 26, at which time all of the blades would be removed from the dampers. Unit 2 would then be run until the scheduled March 5, 1993 outage, at which time all CFCU blades would be replaced with less brittle material. This conclusion of interim operability with cracked blades was based on:

- the low number of (2) cracked blades observed in Unit 2.
- the reliance on leak before break, which would significantly reduce the peak LOCA pressure wave design basis differential pressure for the damper blades of 7 psi.
- the low likelihood of damper blade travel up in the direction of the fan volute.
- the low likelihood of fan damage if a damper blade were to strike a fan blade.

The interim basis for operability, to operate with all damper blades removed, extended from November 26 to the scheduled March 5, 1993, outage. Operability was based on earlier design calculations which concluded that reverse rotation of the fan, if initially running, would not result in CFCU motor breaker trip upon ECCS actuation. The calculation considered the post-LOCA pressure wave, as well as length of time for the CFCUs to sequence on the bus after the SI signal.

The inspector observed that, although licensee internal discussions appeared to have appropriately considered the relevant issues, OE 92-20R0 lacked documentation of many of these specific bases for operability; e.g., the quantitative basis for low likelihood of damage to the fan if a damper blade were to be blown up into the fan, and other concerns.

Inappropriate Information Included in Operability Evaluation:

In OE 92-20R0, the licensee included discussion of the low probability of a LOCA occurring during the interim period before the blades were removed or repaired. Also, the licensee included discussion of the need to consider leak before break, since a licensee topical report on this area has been submitted to the NRC. The results of the NRC safety evaluation have not been issued at this date.

The inspector considered these topics to be inappropriate for an operability evaluation, since plant components must be able to perform the design basis safety function stated in the NRC license, regardless of LOCA probabilities and a leak before break analysis pending NRC review.

Onsite Review Group (OSRG) and Plant Safety Review Group (PSRC)

The OSRG and PSRC reviewed OE 92-20R0. The OSRG issued an action request documenting several concerns regarding the content of the operability evaluation. The PSRC returned the OE to Regulatory Compliance for clarification of the basis for operability. The specifics of these concerns were consistent with many of the inspector's concerns.

The licensee planned to revise the operability evaluation. On November 10, after the end of the inspection period, the licensee removed the two cracked blades from Unit 2, and was considering operation of Unit 2 with all damper blades installed except for those removed due to blade cracking.

Resolution of this issue will be followed by open item 50-323/92-31-01.

b. Inadvertent Bypass of Unit 1 Containment Ventilation Isolation (CVI) Capability

On November 7, 1992, while venting containment, the licensee inadvertently bypassed the radiation monitor which initiates the CVI function. Normal containment isolation functions were not affected. A modification to the containment atmosphere high radiation monitor had been performed during the recent outage, and an operations procedure valve lineup checklist had not been revised to reflect the new configuration. However, the plant vent monitor was in the flow path, and the licensee determined that the release had been well below limits, and had been monitored by the plant vent monitor. The licensee plans to report this occurrence. Corrective actions will addressed during review of the associated LER.

No violations or deviations were identified.

5. Maintenance (62703, 71500)

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 CO 105825, Implement DCN 1-SE-47705, Rod Control Power Supply Replacement.
- Work Order CO 104365, Fire Proofing of Block Wall Structural Steel Supports.
- Post Modification Test 10.06, RHR Flow Control Valves HCV-637, 638, and 670 Flow Test.

No violations or deviations were identified.

6. Identification of Items in Containment Which May Prevent Containment Sump Operability

On March 5, 1992, the licensee issued Licensee Event Report (LER) 50-323/91-12 which indicated that loose materials were found inside the Unit 2 containment in October 1991, during Mode 4 with containment integrity established, and that Technical Specification (TS) surveillance requirement 4.5.2.c had not been met. The surveillance requirement indicates that after establishing containment integrity, a visual inspection of affected containment areas shall be performed to verify that no loose debris are present which could be transported to the sump and cause restriction of pump suctions. The licensee concluded that the loose materials (small plastic bag, wipealls, tool bag, water jug, and tool bin) would not have rendered the containment sump inoperable.

The root cause of this event was determined to be the lack of a comprehensive program for control of material after containment integrity has been established. In response, Surveillance Test Procedure (STP) M-45C and Inter-Departmental Administrative Procedure AD4.ID9 were developed to establish a program for controlling material after containment integrity is established. STP M-45C specified requirements for documenting and inspecting containment work activities, and AD4.ID9 specified containment housekeeping and material control requirements. Step 5.2.2 of AD4.ID9 indicated that all floatable material would either be in use and attended or placed in an approved container, and Step 5.3.3 indicated that all unattended tools and containers should have a "tool reserve tag" attached to prevent inadvertent removal from containment.

On November 5, 1992, the inspector and two licensee QC inspectors walked down portions of the Unit 1 containment while the unit was in Mode 4 with containment integrity established. The inspectors observed unattended loose materials adjacent to the containment sump, including procedures, a pen, two water jugs, mechanical fittings, and a graduated cylinder used to support a hydrostatic test. Adjacent to the containment fan coolers and inside one fan cooler, the inspectors observed unattended tools, testing equipment, a nylon bag, and safety harnesses that were not in an approved container and did not have a "tool reserve tag" attached. The inspectors' observations were brought to the attention of the containment coordinator, and the QC inspectors initiated action requests (ARs) to document the findings. A QC inspector observed more unattended floatable material, consisting of several yellow rags, at the containment sump level on November 7, 1992, and initiated an additional AR.

On November 6, 1992, with Unit 1 in Mode 3, the inspector walked down containment and observed that the materials adjacent to the sump and near the containment fan coolers had been removed. The inspector questioned the presence of open drums near the personnel hatch which were used to collect protective clothing and trash, and was provided a February 1, 1991 document issued by the project engineering group that provided guidelines for radiation protection activities inside containment during Modes 3 and 4. The guidelines indicated that scissor stands were acceptable for collecting clothing and trash, but the stands were to be covered to ensure that the materials would not become dislodged if containment spray actuated. When contacted regarding the actual practice used, the Manager of Radiation Protection indicated that the drums had holes drilled in them to prevent filling with water, and an AR to evaluate the use of the drums had been initiated after the inspector questioned the practice. The inspector later noted that the drums contained bags, and drilling holes in the drums would not prevent the bags from filling with water and the materials in the bags from becoming dislodged. During the conversation, the inspector expressed a concern that the radiation protection guidelines did not appear to have been implemented by procedures that were developed to control material inside containment.

The safety significance of the loose materials appeared low due to the small amount of material present. However, the inspector's observations indicated that the licensee's program to control material inside containment was not comprehensive, and that the corrective actions indicated in the LER were not sufficient to prevent recurrence.

In the exit meeting on November 17, 1992, the licensee indicated that lessons learned from the Unit 1 outage would be incorporated into the procedures for controlling materials in containment prior to the next outage. The licensee also indicated that radiation protection practices would be reviewed and incorporated, as necessary, into procedures. The failure to provide adequate corrective actions to prevent loose material adjacent to the sump when containment integrity was established appeared to violate 10 CFR 50 Appendix B, Criterion XVI (50-275/92-31-02). In

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view of the licensee's immediate and proposed corrective actions to include additional training of personnel performing work in containment during operating modes 1 through 4, and to provide additional control of health physics equipment and protective clothing in containment, no response to this violation is required. LER 50-323/91-12 is closed and followup actions will be tracked by the enforcement item.

One violation of NRC requirements was identified.

7. Modification to Residual Heat Removal (RHR) System (37700)

Because of the safety importance of the RHR system, the inspectors reviewed modification design change package (DCP) N-45952, which changed RHR valves HCV-637, 638, and 670 from butterfly to ball valves. The modification was performed primarily to prevent RHR pump runout should HCV-637 and/or HCV-638 fail open during refueling mid-loop operation, and to reduce flow-induced vibration and associated problems due to the flow characteristics of the original butterfly valves. The licensee determined that the new ball valves have a higher flow coefficient than the old butterfly valves. Consequently, the licensee recognized the importance of limiting the open position of the ball valves and appropriately included post-modification tests to determine the maximum open position for the ball valves.

The inspectors reviewed the post-modification testing and modification analyses to verify the capability of the RHR system to perform its intended function for each of the required operating modes. The inspectors found that the post-modification testing for DCP N-45952 appeared adequate. The inspectors noted the following:

- The Emergency Operating Procedures (EOPs) indicated a potential for one RHR pump to provide flow to the reactor primary coolant hot legs, two safety injection pumps, and two centrifugal charging pumps at the same time. The licensee stated that the maximum single pump flow rate under these conditions could approach 5250 gallons per minute (GPM) in the case of a common mode instrument air failure causing air operated valves HCV 637, 638, and 670 to fail to their open positions. Based on the certified pump curve, the net positive suction head calculation, and the maximum motor amps, the licensee determined the maximum allowable flow for the RHR pumps to be 5500 GPM at runout.

- Results from licensee tests performed to simulate the shutdown cooling mode demonstrated the potential for RHR pump runout for the case of a common mode instrument air failure causing valves HCV-637, 638, and 670 to fail to their open positions. According to the licensee, procedures to preclude RHR pump runout have been implemented during the shutdown cooling mode.

In addition to replacing three butterfly valves with ball valves, DCP N-45952 relocated two of the valves, HCV-637 and 638, to a different area. This required rerouting of associated piping and modifications to pipe supports. The inspectors noted that the licensee's Quality Assurance organization appeared to have recognized the safety importance of this significant change in piping configuration. The inspectors reviewed Quality Performance and Assessment (QP&A) Report Number 92-0023 on this subject. In general, the surveillance appeared to have covered most of the critical parameters, one exception being evaluation of pipe displacements for potential interferences. In discussions with the licensee's pipe stress engineers, the inspectors determined that the licensee appeared to have adequately addressed this issue.

In reviewing QP&A Report Number 92-0023, the inspectors observed that some points made in the surveillance report were either unclear or inaccurate. For example:

- In the section on seismic spectra the report referred to "zero period acceleration" as "zero point acceleration" and in that context indicated "system acceleration = 0." Zero period acceleration should refer to the acceleration in the rigid range of the response spectra.

- The report section which discussed seismic and dilation (containment expansion under pressure) displacements used "extrapolation" instead of "interpolation" to discuss determination of seismic anchor motion displacements. The licensee's stress group actually used linear interpolation methods.

The inspectors interviewed the auditor who prepared the subject surveillance report in order to clarify report statements and to review the auditor's qualifications. The auditor appeared knowledgeable of stress analysis methods. During the exit meeting, the inspectors emphasized the importance of clear, accurate reports in implementing an effective quality review program.

No violations or deviations were identified.

8. <u>Surveillance (61726)</u>

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.

- STP M-45C, Outage Management Containment Inspection.

- STP I-1A, Modes 1, 2, and 3 Shift Checklist.

- STP I-16A2B, Actuation Logic Test of Protection System Logic, Including Master Relays and Reactor Trip Breakers (Mode 1, 2, 3, and 4).

- STP P-6B, Routine Surveillance Test of Steam Driven Auxiliary Feedwater Pump.

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

No violations or deviations were identified.

9. Engineered Safety Feature Verification (71710)

During the inspection period, selected portions of the solid state protection system (SSPS) for Units 1 and 2 were inspected to verify that system configuration, equipment condition, and electrical lineups, and local breaker positions were in accordance with plant drawings and Technical Specifications.

No violations or deviations were identified.

10. Observation of Licensed Operator Training (41701)

On November 4, 1992, the inspectors observed licensed operator training in the simulator (Course LR92, Lesson LR923S5). The training addressed systematic problem solving skills required during plant transients and events. Skills exercised and discussed included individual diagnostics skills, team communications, and team diagnostic skills. The lesson consisted of several short exercises which isolated and emphasized elements of problem solving and teamwork skills involved in arriving at a group consensus of plant conditions.

No violations or deviations were identified.

11. Temporary Instruction (TI) 2500/20, (Closed - Unit 1) "Inspection to Determine Compliance with the ATWS Rule, 10 CFR 50.62."

The inspector walked down the licensee's system to meet the Anticipated Transient Without Scram (ATWS) rule, 10 CFR 50.62. The licensee installed the ATWS Mitigation System Actuation Circuitry (AMSAC) to meet this requirement for both units. The design of the Unit 2 AMSAC was verified in Inspection Report 50-275/323/89-01. The design of the Unit 1 AMSAC system is similar to Unit 2, but had not been walked down by the NRC to verify installation. The results of the walkdown were satisfactory. Based on discussions with the licensee, the system has been available for use most (greater than 95%) of the time. Based on the similar design to Unit 2 and the walkdown, TI 2500/20 is closed.

No violations or deviations were identified.

12. Control of Relief Valves (71707)

During tours of the plant, the inspector observed two items involving the licensee's relief valves that did not appear to be according to the American Society of Mechanical Engineers (ASME) Code. The first was the inconsistent use of seals to assure required relief valve settings. The second involved discharge pipes from several relief valves which were pointed up but did not allow drainage from the low point. These items are discussed below.

Lockwire Seals

The inspector found that one main steam safety valve (2-MS-RV-4) and some diesel air start receiver relief valves (e.g. DEG-2-RV-269) did not have a seal around the setscrews for the guide/nozzle ring settings. This seal provides a positive verification that the settings have not been changed from design values.

ASME Section III Articles NB-7515, NC-7515 and ND-7515 state for Class 1, 2, and 3 relief valves, respectively, that the certificate holder shall install seals at the time of setting a relief valve. Following maintenance on these valves, seals should be installed since the valve has been reset. The main steam safety valve is a Code Class 2 relief valve. The diesel air receiver valve is an ASME Section VIII relief valve, and this code requires the vendor of the relief to install a seal.

The licensee wrote AR A0281812 to document that 2-MS-RV-4 did not have a lockwire seal on it. The licensee concluded that the setscrews had not been repositioned since there was undisturbed rust around the setscrews. The licensee believed that the seals had been installed on this relief valve, but had come off since the last maintenance on the valve (1987). The licensee agreed to install new seals.

In discussions with the inspector concerning the lockwire seal for the diesel air receiver relief, the licensee stated that the requirement for use of seals had changed over time. Originally, relief valves had seals installed by the manufacturer. After initial plant startup, the licensee's program did not require the use of seals. The licensee's program changed about two and one half years ago to require seals following maintenance. The licensee implemented procedures to require seals on May 29, 1991. The current program does require installation of seals on relief valves after setting a valve. The licensee stated that the valves without a seal were last maintained when there was no procedural requirement to install a seal.

Discharge Lines

With respect to the discharge lines pointing upward (vertically) without drainage, an inspector review of ASME Section VIII, Division I (1968) identified that this practice is contrary to Articles UG-126(e) and UG-134(g). This practice is also contrary to ASME Section III, Division I, (1974) Articles NB-7154, NC-7154, and ND-7154. These articles stated that the discharge lines from relieving safety devices shall be designed to facilitate drainage or be fitted with drains to prevent liquid from lodging in the discharge side of the safety device. There was no drainage line observed on the relief valve discharge lines for the diesel air receiver tanks, or on two relief valves for backup air bottles in containment.

The licensee stated that the intent of the Code was to (1) prevent corrosion of the valve internals, (2) prevent static head from affecting lift setpoint, and (3) avoid water hammer in the discharge line if contact with steam results. In subsequent discussions, the licensee stated that the safety concern was low, because the air in the diesel rooms was dry, the possibility of water condensation was low, corrosion had not been observed in relief valves, and that the design met the intent of ASME Section VIII. The licensee also said that a literal reading of the Code would require drains, but they considered their configuration to meet the intent of the Code. However, the licensee made a commitment to promptly request a Code interpretation for the full scope of Code controlled relief valves, and to inform the NRC of intended actions to comply with that interpretation. Resolution of this concern will be followed by Open Item 50-275/92-31-03.

No violations or deviations were identified.

13. Temporary Modifications (92701, 37700)

The inspector assessed a licensee program which controls temporary modifications. Temporary modifications are temporary changes to the plant which include lifted electrical leads, electrical jumpers, and temporary bypass lines. Temporary modifications are required to be controlled by approved procedures, independently verified, and have a log maintained of the status of the temporary modifications. The inspector reviewed the licensee Administrative Procedure (AP) C-4S1, "Temporary Modification Control - Plant Jumpers."

Temporary Jumpers

The licensee's procedure defined jumpers as electrical jumpers, lifted electrical leads, and mechanical bypasses. The procedure required a shift manager approval prior to jumper installation, identification tags on the jumper, an engineering review within fourteen days after installation, and field walkdowns every ninety days.

The inspector noted that the total number of jumpers between both units was about 30, with no installation older than 2 1/2 years and the majority less than one year old. The inspector also reviewed recent Quality Assurance (QA) observations of temporary modifications. No problems were identified with the placement of jumpers which the inspector examined.

The inspector reviewed data sheets on October 19, 1992, and found problems with the administration and attention to detail of the quarterly (i.e., 90 day) review of plant jumpers. AP C-4S1, step 6.4.6 required the installing department to walk down the plant jumper every 90 days following installation, and document this activity on the jumper log form. The problems identified with quarterly reviews included: (1) some historic reviews had taken greater than the required 90 days, (2) one review (jumper in place about a year) had not been done, (3) two currently due reviews were late, and (4) incorrect review dates had been logged. When informed of the inspector's observations, the licensee issued Quality Evaluation (QE) Q0010166.

The inspector found that the historic reviews exceeding 90 days all occurred in the same period (September 1991 through January 1992). One jumper (Unit 2, 91-045) had not had a 90 day review, although it had been installed since October 17, 1991. The inspector also found that two jumpers were late for their current 90 day review, not having been reviewed since July 13, 1992 (98 days), and that five jumpers had their quarterly review incorrectly logged as having been completed on October 21, 1992, two days after the date of the inspector's review.

The unit, log numbers, and problems identified are summarized below.

UNIT	Log Number	Historic Reviews > 90 days	Review done	Current Review Late	Review Date Mislogged
1	90-009	140, 177, 121 days	Yes	No	No
1	91-052	121 days	Yes	No	No
1, 2	91-060	121 days	Yes	No	No
1, 2	91-061	121 days	Yes	No	Yes
2	90-028	169, 178, 121 days	Yes	No	No
2	90-057	121 days	Yes	No	No
2	90-086	122 days	Yes	No	Yes
2	91-029	115 days	Yes	No	No
2	91-045	None	No	No	No
2	91-051	None	Yes	No	Yes
2	91-052	None	Yes	No	Yes
2	91-056	None	Yes	Yes	No
2	91-061	None	Yes	No	Yes
2	92-015	None	Yes	Yes	No

The licensee found that jumper 91-045 had not been walked down because the I&C department installed the jumper and believed that operations would verify the jumper, since it was in containment. The operations department was unaware of the need to verify the jumper. The jumper was subsequently verified on October 28, 1992, as still installed.

The licensee verified the two jumpers that were late for their 90 day review on October 22, 1992. The licensee also stated that the logs had incorrect dates for five jumpers due to a transposition error from the previous log entry. All of the previous log entries were 7/21/92, and the log entries were copied as 10/21/92 for the five jumpers.

The licensee's root cause evaluation determined these problems had been caused by personnel error. The errors were: (1) inattention to detail,

(2) personnel not completely understanding the requirements of procedure AP C-4S1, and (3) departmental roles in the program not having been adequately stated. The licensee counseled individuals and initiated procedure changes to AP C-4S1.

Although no safety concern regarding the placement or control of jumpers was identified, the licensee's weaknesses in administrative review of the jumper program, and failure to follow procedure AP C-4S1, is an apparent violation (Severity Level V) of TS Section 6.8.1, which requires that activities be implemented according to procedures (50-275/92-31-04). This violation is not being cited because the criteria specified in Section VII.B.1 of the Enforcement Policy were satisfied.

One non-cited violation was identified.

14. Licensee Event Report (LER) Followup (92700)

The following LERs were reviewed and closed based on the licensee's root cause determination and corrective actions:

Unit 1: 92-10 Revision 0, 92-20 Revision 0, 92-05 Revisions 0 and 1.

Unit 2: 92-01 Revision 2, 92-04 Revision 0.

a. LER 50-275/92-04 Revision 1 and 2 (closed)

These LERs described a loss of offsite power that occurred on March 7, 1991, while Unit 2 was in a refueling outage. An NRC Augmented Inspection Team investigated the event and documented their findings in NRC Inspection Report 50-275/91-09. These LERs are closed because followup actions for the event were tracked by open items associated with the inspection report.

b. LER 50-275/91-18 Revisions 0 and 1 (closed)

These LERs described certain plant conditions and system configurations that could result in component cooling water temperatures exceeding design basis limits. The licensee identified this problem during an investigation to determine the viability of a potential change to plant Technical Specifications. The licensee subsequently revised emergency operating procedures (EOPs) to ensure the undesirable system configurations would not be used. This item is closed based on the revisions made to the EOPs. Followup item 50-275/92-16-04 will be used to track the licensee's engineering evaluation of their design basis.

c. LER 50-275/92-19 Revisions 0 and 1 (closed)

These LERs described improper maintenance of containment fan cooler units. This issue was the subject of a special NRC inspection and an enforcement conference documented by NRC Inspection Reports 50-275/323/92-17 and 50-275/323/92-19. The LERs are closed because the followup actions are being tracked by enforcement items 50-275/92-17-01 and 02, along with enforcement item 50-323/92-17-03.

d. LER 50-275/92-22 Revision 0, Unit 1 Indications in Main Feedwater Piping Near Steam Generator Nozzles Due to Thermal Fatigue (closed)

The licensee identified linear indications of cracks in a weld near the steam generator nozzles in all four Unit 1 steam generators. Based on the estimated depth of the indications, and past occurrences of thermal fatigue in 1985, the licensee replaced the piping segment in all four feedwater lines. Later destructive analysis of the welds showed that the crack size had been overestimated by about a factor of ten.

A management meeting was held on October 16, 1992, with the licensee in the Region V office to discuss the crack indications on the feedwater pipe adjacent to the steam generator feedwater nozzles. According to the licensee, the cracks had likely occurred as a result of thermal fatigue from thermal stratification during low feedwater flow conditions. The licensee had removed the affected sections of feedwater piping. The licensee presented documentation that showed actual crack depths were an order of magnitude smaller than the crack depth measurements initially indicated by conservative UT examination. According to the licensee, the actual maximum crack depth was significantly less than that allowed by the ASME Section XI code guidance for maximum allowable flaw depth.

Followup and corrective actions performed by the licensee included:

- Replacement of the ASME A-106 Grade B feedwater piping with stronger ASME A-508 material (the same material as the adjacent steam generator feedwater nozzles).
- Analyses which estimated the effect of thermal stratification on the feedwater piping based on assumed temperature distributions.
- Instrumentation of the affected feedwater piping to determine actual temperature distributions.

Region V and NRR staff reviewed the licensee's approach, including preliminary analysis results, and concluded that they appeared appropriate. Further review of results and validation of calculation assumptions will be performed when data become available. A copy of the licensee's presentation on the feedwater piping cracking issue is included as an attachment to this report.

15. Eddy Current Testing of Steam Generator Tubes (73755, 73052)

The inspector reviewed the licensee's program and procedures and the preliminary results of eddy current testing (ECT) of steam generator tubes conducted during the 1R5 outage. Persons contacted during this inspection activity are listed in the appendix to this report.

The inspector reviewed the following licensee documents and procedures.

200501

- Nuclear Plant Administrative Procedure (NPAP) C-804, "Inservice Inspection and Testing Program," Revision 0.
- Field Service Procedure MRS 2.4.2 PGE-35, "Eddy Current Inspection of Inservice Steam Generator Nonferromagnetic Tubing for Diablo Canyon Units 1 & 2," Revision 0.
- Technical and Ecological Services "Steam Generator Eddy Current Data Analysis Guidelines," Revision 1.

a. <u>ECT Program and Procedures</u>

The inspector found that the licensee's ECT program incorporated state of the art technology for the detection of tube degradation including bobbin coil probes, rotating pancake coil (RPC) probes, multi-frequency analysis, and optical disk data storage. The licensee's inspection sample size and data analysis had been conservatively developed consistent with technical specification requirements and the recommendations of the Electrical Power Research Institute (EPRI).

The following weaknesses were identified during the inspector's review of the licensee's program.

(1) <u>Loose Parts Monitoring</u>

The inspector noted that the licensee's program was based on Electric Power Research Institute (EPRI) guidelines for steam generator examinations. The EPRI guidelines recommended followup of eddy current indications suggesting the presence of a foreign object.

The inspector noted that the licensee's ECT data analysis guidelines did consider loose parts in the secondary side of the steam generator tube bundle as a possible cause for individual tube wear indications. However, the ECT program did not include followup provisions for specifically locating and characterizing the loose parts or examining additional tubes surrounding a suspected foreign object.

According to the licensee, eddy current inspection was used to supplement their program of visual inspection for loose parts in the secondary side of the steam generator tube bundle. If a foreign object was visually located, then adjacent tubing would be identified for ECT to assess any resulting tube wear.

Industry events related to steam generator tube defects have been attributed to loose parts. The inspector noted that examination for loose parts did not appear to be a priority in the licensee's ECT program.

The licensee stated that they had not experienced a significant problem with loose parts causing tubing wear. However, the licensee acknowledged the inspector's concern and committed to review their data analysis guidelines to enhance their use of ECT data for monitoring for loose parts in the steam generator tube bundle. The inspector found the licensee's proposed actions to be adequate.

(2) Data Analysis Guidelines Not Issued as a Plant Procedure

The inspector found that the licensee utilized written guidelines for the analysis of eddy current data. However, these guidelines were not issued as a formal plant procedure. The guidelines had been developed by the licensee's Technical and Ecological Services (TES) division for use by contractor inspection personnel at the plant. Contract analysts received training at the plant in the use of the guidelines and conducted their evaluations of the eddy current inspection data in accordance with the guidelines. The inspector noted that the lack of formal procedural control of the inspection guidelines could result in inadequate documentation of the data evaluation criteria used in each outage.

The licensee acknowledged the need to formally control the data analysis guidelines and committed to issue the guidelines as formal plant procedures by the 2R5 outage. The inspector found the licensee's proposed actions adequate.

(3) Defect Acceptance Criteria Not Identified in Plant Procedure

The inspector found that the licensee determined the need for tube plugging based primarily on the results of their evaluation of the eddy current inspection data. As a minimum, the licensee utilized the plugging limit acceptance criteria contained in Technical Specification 4.4.5.4. In addition, preventive plugging based on an administrative decision was used in some cases. However, the inspector found that the defect acceptance criteria were not specifically identified in the licensee's procedures. The inspector noted that defect acceptance criteria were included in the data analysis guidelines which the licensee used to characterize eddy current indications.

The license acknowledged the need to formally define and control the tube defect acceptance criteria used for eddy current inspection. The licensee committed to incorporate specific defect acceptance criteria within plant procedures by the 2R5 outage. The inspector found the licensee's proposed actions to be adequate.

b. Review of 1R5 Eddy Current Inspection Results

The inspector reviewed the preliminary results of the licensee's eddy current inspection of steam generator tubes during the ongoing 1R5 outage. The inspector noted that the initial sample size had been expanded as required due to defect indications in all steam generators. A total of 29 tubes were plugged during the 1R5 outage due to continuing tube wear at anti-vibration bar (AVB) locations and crack indications in the short radius U-bend tube areas. The licensee's 1R5 inspection activities appeared consistent with their committed program and technical specification requirements. No concerns were identified during this review.

No violations or deviations were identified.

16. Exit Meeting

An exit meeting was conducted on November 17, 1992, 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 did not identify as proprietary any of the materials reviewed by or discussed with the inspectors during this inspection.

APPENDIX

Persons Contacted during Eddy Current Testing Inspection (Paragraph 15)

*S. Banton, Director, Plant Engineering
*W. Barkhuff, Director, Quality Control
*W. Crockett, Manager, Technical Services
*R. Exner, Project Manager, Maintenance
*C. Groff, Technical Services
D. Gonzales, Inservice Inspection Coordinator, Technical Services
D. Hampshire, Technical Coordinator, Nuclear Operations Services (NOS)
J. Kang, Analyst, Technical and Ecological Services (TES)
H. Karnar, Auditor, Quality Assurance
*D. Miklush, Manager, Operations Services
*D. Moon, Regulatory Compliance
*D. Taggart, Director, Quality Assurance
*J. Townsend, Vice President
*R. Thierry, Regulatory Compliance
A. Young, Manager, Quality Assurance

*Attended the exit interview on October 9. 1992.