U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Numbers: 50-275/93-31 and 50-323/93-31

Docket Numbers: 50-275 and 50-323

License Numbers: 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 and Pacific Gas and Electric Company Office, 33 Market Street, San Francisco, California

Inspection Date: November 15 through November 24, 1993

Inspectors: D. Acker, Reactor Inspector

Approved By: W. P. Ang, Chief, Engineering Section — 12-13-93 Date Signed

Summary:

Inspection from November 15 through November 24, 1993 (Report Nos. 50-275/93-31 and 50-323/93-31)

Areas Inspected:

The areas inspected in this announced routine engineering inspection included auxiliary salt water cable failures, seismic design modifications, and open items. Inspection Procedures 37700, "Design Changes;" 92700, "Followup of Written Reports;" and 92701, "Followup of Open Items;" were used as guidance for this inspection.

Results:

General Conclusions and Specific Findings:

NRC staff and licensee definitions of a 10 CFR 100 Appendix A safe shutdown earthquake appeared to differ. However, the inspector did not identify any examples of failure of the licensee to comply with NRC seismic requirements.

Licensee actions to correct self-identified seismic qualification problems appeared adequate.

The licensee was unable to identify root causes for recent failures of safety related four kilovolt underground cables. However, licensee corrective actions to preclude recurrence of the failures appeared to be reasonable.

Significant Safety Matters:

None

Summary of Violations:

None

Open Items Summary:

Three LERs and one followup item were closed. One followup item was opened in Section 2.a.

Safety Issues Management System (SIMS) Items:

None

DETAILS

1. Persons Contacted

Pacific Gas and Electric Company

*B. Crockett, Manager, Technical and Support Services
*T. Grebel, Supervisor, Regulatory Compliance
*K. Hubbard, Engineer, Regulatory Compliance
*C. Pendleton, Acting Director, Mechanical Maintenance
H. Thailer, Director, Civil, Piping, Equipment Qualification, Nuclear Engineering Services
*J. Townsend, Vice President and Plant Manager

*Denotes those attending the exit meeting on November 24, 1993.

NRC

*W. Ang, Engineering Section Chief, Region V
*M. Miller, Senior Resident Inspector

The inspector also held discussions with other licensee personnel during the inspection, including inspections performed at the corporate office in San Francisco on November 15, 1993.

2. Hosgri Earthquake Criteria (37700)

On June 22, 1992, in a meeting held in the Region V NRC office, the licensee reported failure to comply with certain Hosgri earthquake commitments. The results of the June meeting were documented in NRC Inspection Reports 50-323, 50-275/92-20. Subsequently, the licensee issued voluntary LER 01-92-15, "Inadequate Maintenance of Hosgri Report Commitments." Although this LER was closed in Inspection Reports 50-323, 50-275/92-33, the inspector considered that an additional review of design changes and seismic criteria was warranted. The inspector noted that the latest addition of the licensee's Hosgri earthquake report was Amendment 83, dated June 1980; subsequent seismic changes were incorporated in the Updated Final Safety Analysis Report (UFSAR).

The inspector reviewed the licensee's UFSAR, Hosgri Seismic Evaluation Report, and various NRC staff Supplemental Safety Evaluation Reports (SSER) to determine the adequacy of the licensee's maintenance of seismic qualification for new or modified equipment. The inspector also reviewed the status of licensee actions taken to resolve the problems noted in the June 22, 1992, meeting.

a. Safe Shutdown Earthquake

The inspector noted that the NRC staff's definition of a 10 CFR Part 100 safe shutdown earthquake (SSE) appeared to differ from the licensee's definition contained in UFSAR Section 3.2.1. However, the inspector did not identify any failure of the licensee to comply with NRC seismic requirements.

The licensee's position, as reflected in the UFSAR, Revision 9, dated November 1993, Section 3.2.1 was, "The SSE of Appendix A to 10 CFR 100, is equivalent to the DCPP double design earthquake. ...DCPP's capability to withstand a postulated Richter magnitude 7.5 earthquake centered along an offshore zone of geologic faulting known as the "Hosgri Fault" is reviewed." The double design earthquake assumed a peak ground acceleration (PGA) of 0.4g at the site while the Hosgri earthquake assumed a PGA of 0.75g.

The NRC staff's position, as reflected in SSER 7, dated May 1978, was that the Hosgri earthquake was the 10 CFR Part 100 Appendix A SSE. This SSER noted at the time that there was a disagreement over the definition of the SSE but noted that, "...[the] disagreement over which event is the SSE has no bearing on plant safety since, whatever name is assigned to the event, we require that the plant design be shown to be adequate for the Hosgri event...."

The staff's position was further reflected in SSER 31, dated June 1991, page 1-2 which stated, "the NRC required that the SSE for Diablo Canyon be established as a horizontal PGA of 0.75g based on a postulated magnitude 7.5 earthquake on the Hosgri fault...."

The inspector reviewed SSERs 7, 8, and 31 and the UFSAR and did not identify any technical differences in Hosgri requirements between what the NRC required for Hosgri and what the licensee's UFSAR stated had been accomplished. However, since recent NRC and licensee definitions of the SSE were still not the same, the inspector concluded that a more detailed review was warranted. Open item 50-323, 50-323/93-31-01 has been assigned to track and document this NRC review.

b. <u>Licensee Identified Non-Conformance to Hosgri Commitments</u>

In 1990 the licensee identified that two replacement instrument transmitters had not been properly qualified for a Hosgri earthquake. The licensee initiated non-conformance report (NCR) DCO-90-EN-27 to investigate this issue. During the investigation the licensee identified a number of areas where they were not in compliance with their Hosgri commitments. The licensee briefed the NRC staff on the Hosgri problems and their corrective actions during the June 22, 1992, meeting discussed in Section 2.a.

The licensee identified five areas of non-compliance with Hosgri commitments.

- Two replacement instruments were not seismically qualified.
- Other instruments and motor operators did not have explicit seismic qualification files.
- The listing of valves required to be seismically qualified for

a Hosgri earthquake was incorrect and incomplete. Existing seismic qualifications for some valves were less than required for a Hosgri earthquake.

- Electrical panels and switches were not adequately qualified.

- Seismic qualification files had not been maintained for required Reactor Coolant Sampling system equipment.

The inspector reviewed NCR DCO-90-EN-027 and considered that the most significant area of non-compliance was with valve qualifications. For example, a licensee memorandum of January 29, 1992, identified 34 valves which did not meet the existing allowable accelerations for a Hosgri earthquake and 19 valves which were required to operate during a Hosgri earthquake, but were not qualified to do so.

The inspector determined that the licensee had accomplished a broad scope review of seismic qualifications in NCR DCO-90-EN-027. Revision 2 of this NCR, dated October 25, 1993, stated that all required seismic qualifications had been completed and only minor equipment modifications remained.

The inspector reviewed the revised qualifications for a number of the valves listed in the January 29, 1992, memorandum and determined that the valves had been qualified to withstand the calculated maximum Hosgri accelerations. The inspector selected four of these valves and reviewed with the licensee the qualification calculations. The calculations indicated that the valves were qualified for calculated maximum Hosgri accelerations.

The inspector concluded that the licensee had taken appropriate action to correct the Hosgri compliance problems documented in NCR DCO-90-EN-27.

No violations or deviations from NRC requirements were identified in the areas reviewed.

3. Onsite Followup of Written Reports (92700)

a. (Closed) 50-275, 50-323 Voluntary Licensee Event Report 01-93-05, Revision 0 and Revision 1: Medium Voltage Cable Failures

Reported Problem

Voluntary Licensee Event Report (LER) 01-93-05 reported five failures of buried 12 kilovolt (KV) and 4 KV cables, one in 1989, two in 1992 and two in 1993. Severe jacket degradation caused two failures of Unit 1 12 KV circulating water pump (CWP) cables. There were also three 4 KV cable failures, two in power cables for safety related auxiliary salt water (ASW) pumps. However, no jacket

degradation was found for the 4 KV cables. All five failed cables were found to have been submerged in water. These problems were previously discussed in NRC Inspection Reports 50-275, 50-323/93-03, 93-07, and 93-17.

Initial Corrective Action

The licensee replaced the failed cable sections. As a result of the CWP failures the licensee replaced sections of the three remaining CWP cables in Unit 1. The sections replaced were in the same locations as in the failed cables.

During the 1993 Unit 2 refueling outage, the licensee also replaced the same section of the ASW pump 1-1 cables (these cables had not failed), as a precautionary measure. No jacket degradation was found on the removed cables. In addition, the licensee replaced the entire length of one Unit 2 CWP 2-1 cable (1400 feet) to allow evaluation of one entire cable. No jacket degradation was found on the removed cable.

The licensee determined that the cables had been submerged in water due to inoperable sump pumps. The licensee repaired the pumps and initiated a preventive maintenance task to routinely maintain these pumps.

After the original LER was issued, the licensee obtained additional laboratory analyses of the cables. In addition, the licensee formed an Integrated Problem Response Team which performed a detailed root cause of the problem. The licensee issued Revision 1 to the LER on October 4, 1993. This revision noted the licensee had sent samples of all cables to three independent laboratories for analysis. The laboratories determined that the 12 KV cable jackets had failed due to chemical attack. The laboratories were not able to determine the cause of the 4 KV cable failures. The licensee concluded that the 12 KV cable failures and the 4 KV cable failures did not have a common cause. The licensee also concluded that the individual 4 KV cable failures could not to traced to a common cause.

Additional Revision 1 Corrective Actions

The licensee stated that they planned to continue routine megger and high potential testing of the 4 KV cables. In addition, they planned to develop a long term program for cable aging.

The licensee initiated Design Change Notice (DCN) OSC47519, "Install Four Inch Diameter Access Holes," to allow quick visual inspection of the sumps containing the 4 KV cables. The licensee initiated Action Request A0308121, "Request Policy to Inspect Pull Box Holes," to set a policy for routine inspection of the sumps once the access holes have been cut.

The licensee committed to reactivate a sump level alarm system for

the sumps and drains immediately outside the turbine building. The system had not been kept active prior to the cable failures.

The licensee committed to investigate new cable specifications for future cable replacements.

The licensee committed to replace one complete circuit from the turbine building to the motor terminations for Unit 1 ASW pump 1-2 during the March 1994 refueling outage. The licensee committed to send samples of the removed cable for laboratory analysis.

Inspector's Review

The inspector reviewed the licensee's actions to date, laboratory reports and the Integrated Problem Response Team's findings and root cause evaluations.

The inspector reviewed the licensee's preventive maintenance program and verified that the applicable sump pumps were identified for routine preventive maintenance.

The inspector sighted CWP and ASW cable samples removed from Unit 1 during cable replacements.

The inspector sighted the Unit 1 sumps and ASW and CWP cables immediately outside the turbine building and determined that they were dry and showed no signs of recent water intrusion. The inspector noted that the sump covers immediately outside the turbine building were not difficult to remove.

Discussion and Conclusion

Laboratory information indicated that high levels of chlorides were found in water samples taken from the sumps. The laboratory concluded that salt water spray was washed from the turbine building exterior surface into the sumps by rain water. An unidentified chemical, similar to a cleaning agent, was also identified. A specific chemical compound could not be identified, due to the small amount of chemical present for analysis. The unidentified chemical was postulated to have attacked the 12 KV CWP cables and may have been carried into the sumps via rain water.

Laboratory tests determined that the construction of the 4 KV cable jackets was more resistant to chemical attack than the 12 KV cables, due to a more dense construction. In addition, the chemical which degraded the 12 KV cables was not found on the 4 KV cables, however, the chemical concentration was very low and difficult to detect. The inspector concluded, based on cable locations in the sumps, that chemicals found on the CWP cables could also have been present on the ASW cables.

Extensive electrical testing of the 4 KV cable insulation had not

identified any significant manufacturing flaws. Detailed microscopic examinations of the areas of cable failures also did not identify a cause of the failures.

The inspector, based on sighting failed ASW and CWP cables and review of the laboratory results, considered that the licensee's conclusion that the ASW and CWP cable failures did not result from a common cause was correct. The inspector concluded that the licensee had taken reasonable action to attempt to identify the root causes of the three 4 KV cable failures and had initiated adequate measures to limit the potential for future 4 KV cable failures. Revision 0 and Revision 1 of this LER are closed.

b. (Closed) 50-275, 50-323 Licensee Event Report 01-92-01: Check Valve Not Tested

Reported Problem

Licensee Event Report (LER), Revision 0, dated April 30, 1992, reported that check valve Chemical Volume and Control System (CVCS) 8440 had not been tested as required by American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section 11. The licensee identified the problem during a review of industry operating experience events. The licensee determined the root cause of this omission was failure to recognize the safety function of this valve. The check valve prevented potential leakage of post-LOCA recirculation water through the seal water heat exchanger, and potentially outside containment via the volume control tank.

Corrective Action

The licensee added CVCS 8440 to their ASME Section 11 testing program. The licensee committed to review the post-LOCA recirculation flow path to determine whether there were other Section 11 omissions. The licensee updated their design control manual to note the function of this check valve.

Inspector's Review

The inspector reviewed the licensee's procedure for testing check valve CVCS 8440, Surveillance Test Procedure (STP) M-86G, "NUREG-0578: Charging System (Suction) Leak Reduction and Leak Check of CVCS-8440, VCT Outlet Check to Charging Pumps Suction." The inspector reviewed the licensee's Design Criteria Memorandum (DCM) S-8, "Chemical Volume and Control System."

Discussion and Conclusion

The inspector determined that STP M-86G provided adequate instructions to test check valve CVCS-8440 and that DCM S-8 contained an adequate functional description of the valve. However, the inspector could find no documentation that the review of the

post-LOCA recirculation flow path for similar omissions had been accomplished. The inspector discussed this review with the licensee. The licensee stated that the review had been completed but not documented. The licensee subsequently documented the review during the inspection and noted that no additional omissions were found.

The inspector concluded that the licensee's actions were adequate. LER 01-92-01 is closed.

c. (Closed) 50-275, 50-323 Licensee Event Report 01-83-39, Revision 2: Control Room Ventilation System Outside Design Basis

Reported Problem

Licensee Event Report (LER) 83-39, Revision 2, reported that failure of one of the redundant booster fans or booster fan dampers could potentially cause the control room ventilation system to be outside its design basis.

The licensee further determined that failure of an operating booster fan, or fan damper would not cause an alarm nor start the redundant unit. Failure of the operating booster fan could allow unfiltered air to enter the control room via recirculation ducting. The licensee determined in 1991 that this condition had existed since 1983.

The licensee investigated the cause of this design problem and concluded that the primary cause was personnel error.

Corrective Action for Revisions 0 and 1

The licensee issued an operations night order that discussed the possible failure of a booster fan or fan damper.

The licensee committed to make design changes which would start the redundant fan upon loss of an operating fan.

As an interim corrective action the licensee installed streamers on the control room ventilation recirculation ducts. The licensee revised emergency procedure (EP) E-0, "Loss of Reactor or Secondary Coolant," to include instructions to operators to confirm proper control room ventilation.

Corrective Action for Revision 2

The licensee determined that the streamers were an adequate design to indicate the failure and that no other design changes would be made. The licensee added a routine test to check the operation of the streamers and fans in Surveillance Test Procedure (STP) M-6A, "Routine Surveillance Testing of CRVS [Control Room Ventilation System]."

Inspectors' Review

The inspector reviewed LER 01-83-39, Revisions 0, 1, and 2. The inspector determined that Revisions 0 and 1 were closed by Inspection Report 50-275, 50-323/93-01. The inspector reviewed EP E-0, Revision 6 and STP M-6A, Revision 16 with Unit 2 control room operators. The inspectors visually inspected the streamers.

Discussion and Conclusion

Based on discussions with Unit 2 control room operators the inspector concluded that operators were aware of the significance of the streamers. The inspector noted that the streamers were visible in the control room. The inspector concluded that EP E-0 and the streamers would provide the operators sufficient information to alert them to unfiltered reverse ventilation flow via the recirculation ducts.

The inspector concluded that STP M-6A provided a valid test for routinely verifying that the streamers would indicate improper flow.

Revision 2 of LER 01-83-39 is closed.

No violations or deviations from NRC requirements were identified in the areas inspected.

4. Previously Identified Open Items (92701)

a. (Open) Unresolved Item 50-275, 50-323/88-02-01: Regulatory Guide 1.97 Requirements Not Being Met

Original NRC Unresolved Item

The inspector determined that three areas of the licensee's Regulatory Guide (RG) 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," instrumentation design did not appear to meet the licensee's commitment to RG 1.97 requirements. The technical areas of concern involved electrical separation between Class 1E and non-Class 1E systems, lack of neutron flux recording capability and lack of redundant equipment.

Licensee's Actions in Response to the Unresolved Item

The licensee initiated an extensive program for review of their RG 1.97 commitments. The licensee identified a number of areas of non-compliance. The licensee had been working to upgrade the units to meet their commitments and had been providing the NRC staff with periodic updates of their findings and corrective actions.

Inspector's Review

The inspector picked two areas for review. First, the inspector reviewed a sample of the licensee's actions to resolve the problems they identified that were not in compliance with their RG 1.97 commitments. Second, the inspector reviewed electrical separation and isolation problems which were not associated with RG 1.97 instrumentation. The inspector chose to review electrical separation and isolation problems which were not associated with RG 1.97 instrumentation to determine if the separation and isolation problems identified with RG 1.97 instrumentation were indicative of a larger generic problem. The licensee, in letter DCL-93-078 to the NRC staff, dated April 6, 1993, had identified that they were also reviewing the potential for electrical isolation problems with all Class 1E power circuits.

The inspector picked the Containment Valve Position Indication Monitoring (CVPI) system for review of licensee identified RG 1.97 problems. The CVPI system was one of four RG 1.97 systems identified by the licensee as potentially not meeting their commitments. The licensee identified this system as a Class 1E system, instrument Class 1B, RG 1.97 type B variable. Type B variables were those systems that provided information to indicate whether plant safety functions were being accomplished.

The inspector reviewed the Non-Conformance Reports (NCRs) issued from September 1991 through September 1993 to identify problems with electrical separation which were not associated with RG 1.97 instrumentation.

(1). Containment Valve Position Indication Monitoring System

Background

The licensee, in a meeting held at NRC headquarters on December 18, 1991, identified that the CVPI did not meet RG 1.97 requirements for type B variables in that some of the system was Class 2 in lieu of the required Class 1E. Deficiencies from Class 1E requirements were common power supplies, non-environmentally qualified equipment, lack of redundancy and separation in cable trays, and non-seismic analyzed equipment.

The NRC staff, in a letter, "Summary of December 18, 1991 Meeting Held in Rockville, Maryland to Discuss Regulatory Guide (RG) 1.97 Issues Applicable to Diablo Canyon (TAC NOS M79787 and M79788," dated March 11, 1992, stated that the licensee expected to develop a solution for the CVPI problem in about six months.

Inspector's Review During Present Inspection

The inspector determined that the licensee had not yet upgraded

the CVPI system to meet the RG 1.97 requirements. The inspector discussed the status of work on this system with the licensee. The licensee stated that they were developing a proposed solution for this system which would involve system upgrades and a waiver request. The licensee stated that their goal was to finalize their proposed design and submit this design for NRC review and approval by spring 1994. The licensee further noted that attachments to the March 11, 1992, NRC letter indicated that their goal was to complete any design changes for the CVPI system by May 1996. The licensee stated that May 1996 was still their goal.

Because the licensee had not yet determined specific actions to resolve the RG 1.97 CVPI problems, the inspector reviewed their operability determination. Operability Evaluation (OE) 91-13R2, "Operability of Non-Conforming Reg. Guide 1.97 Post Accident Monitoring Instrumentation," dated April 24, 1992, Section II, contained the licensee's operability evaluation for the CVPI system. The licensee concluded that the system was operable.

System Design and Licensee Operability Evaluation

The CVPI system was composed of white lights (WL) and red-green lights (RGL). The WLs provided, in one display box, CVPI status relative to whether containment valves had isolated after receiving a Containment Isolation signal. The system used position indication switches on each valve and associated wiring. Emergency operating procedures required review of the WLs after a reactor trip or safety injection.

The RGL provided operators with valve position indication during normal plant operations and supplemented the WL indication. The system used position indication switches and associated wiring which were generally totally independent of the WL system. The RGLs were, in most cases, located in the control room next to the associated valves. For certain radwaste valves, the RGLs were not located in the control room.

The licensee determined the CVPI was operable based on:

- Determination that the RGL system would remain operable in a seismic event.
- Determination that parts of the WL system which were not environmentally qualified could be qualified.
- Determination that no single credible failure could render inoperable both the WL and RGL systems.
- Case by case evaluation of radwaste valves, which

determined that at least one indicator for each containment isolation valve or valve pair would remain operable for all single credible failures.

- Determination that the system does not initiate any automatic actions.

- Determination that the failure of both inboard and outboard containment isolation valves to close and failure of both WL and RGL indicators was a very small probability.

- Compensatory emergency operating procedures which took into account that the CVPI system was not currently Class 1E.

- Determination that RGL indicator locations outside the control room would be available during post accident conditions.

Discussion and Conclusion

The inspector reviewed OE 91-13R2 and concluded that the licensee evaluation that the CVPI system was currently operable was reasonable. The inspector determined that Emergency Operation Procedure E-1, "Loss of Reactor or Secondary Coolant," contained a step for reverifying the WL indications with the RGL indications, pending design changes to upgrade the system.

(2). Electrical Separation

During the present inspection, the inspector noted that one of the major problems with RG 1.97 compliance at Diablo Canyon was with electrical separation and isolation. The inspector determined that a review of electrical separation problems which were not associated with RG 1.97 instrumentation could indicate if the RG 1.97 separation problems were generic to other Class 1E electrical systems.

Inspector's Review During Present Inspection

The inspector reviewed a listing of NCRs for the last two years (September 1991 through September 1993) to determine the extent of electrical separation and isolation problems identified by the licensee. The inspector also reviewed the licensee's commitments regarding electrical separation and isolation of circuits and the implementing design documents and visually inspected electrical cabinets where recent problems had been found.

Discussion and Conclusions

The inspector identified two NCRs which documented problems with electrical separation or isolation at Diablo Canyon. These NCRs were DCO-91-EN-N001 and DCO-91-EN-N014.

The licensee's Updated Final Safety Analysis Report UFSAR, Section 8.3.1.4 provided electrical separation criteria for Diablo Canyon. The UFSAR stated that the licensee was not committed to RG 1.75, "Independence of Redundant Systems. The licensee was only committed to Institute of Electrical and Electronics Engineers (IEEE) 279-1971, "Criteria for Protection Systems for Nuclear Power Generation Stations," and 308-1971, "Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."

The licensee's design documents for electrical separation were, DCM T-19, "Electrical Separation and Isolation, and DCM T-24, "Design Criteria for DCPP Instrumentation and Controls."

The inspector reviewed sections of DCM T-19 and DCM T-24 and determined that they were consistent with the UFSAR.

The inspector reviewed NCRs DCO-EN-N001 and DCO-EN-N014 and discussed these NCRs with the licensee.

NCR DCO-91-EN-N001 reported two examples where design changes had added non-Class 1E circuits to existing Class 1E circuits; one design change added a Class II main steam isolation valve test circuit to a Class 1E power supply and the other design change added a Class II containment fan cooler overload bypass circuit to a containment fan cooler Class 1E damper control circuit. Both problems were corrected by May 1993. The licensee attributed both problems to personnel errors during preparation of design changes. The licensee reviewed a sampling of electrical schematics for class breaks, and identified with 95 percent confidence that there were no additional circuits where Class II circuits were improperly connected to Class 1E power systems. During this review, the licensee did identify that Class II instruments mounted on emergency diesel generator (EDG) vendor supplied equipment were powered from the same supplies as Class 1E circuits for the same EDG. The licensee determined by failure modes and effects analysis that this design was within their design requirements for electrical isolation and that there was no single credible failure mode for the Class II instruments which would make the Class 1E circuits inoperable. The licensee issued DCM T-19 to provide guidance on electrical separation and isolation.

NCR DCO-91-EN-N014 identified that the separation criteria were not being met in Rack, Nuclear Auxiliary Safeguards A and B (RNASA and RNASB) cabinets. The licensee identified that

mutually redundant safety related Class 1E circuits had been added into the non-Class 1E RNASA and RNASB cabinets by Westinghouse during the initial plant design. Westinghouse, after notification by the licensee, notified the NRC staff by a Part 21 letter dated June 24, 1991. The licensee separated the mutually redundant circuits within the cabinets and performed a failure analysis. The licensee concluded that the existing design met their criteria for single failure.

Independent review by the inspector and the licensee did not identify any additional NCRs with associated electrical separation or isolation issues. The inspector visually inspected the RNASA and RNASB cabinets in Unit 2. The inspector concluded that the areas of the cabinets inspected met the Diablo Canyon electrical separation commitments.

The inspector concluded that although electrical separation and isolation issues had been identified by the licensee within the last two years outside of the RG 1.97 area, that the problems were not excessive and did not indicate a potential generic design flaw. The inspector also concluded that the licensee was taking adequate action to investigate and correct the items identified.

(3). Overall Conclusion

The inspector concluded that the licensee operability evaluation of the CVPI system was adequate and that Diablo Canyon did not have excessive electrical separation problems which would warrant additional inspector followup at this time. The final design of the CVPI system will be reviewed as part of this unresolved item, which was left open pending final licensee resolution of the remaining RG 1.97 problems.

b. (Closed) Followup Item 50-275/93-03-01: Medium Voltage Cable Failures

This item was previously opened to followup on licensee resolution of the underground 12 KV and 4 KV cable failures discussed in Section 3.a of this report. This item is closed based on the inspector's review discussed in Section 3.a.

No violations or deviations from NRC requirements were identified in the areas inspected.

5. Exit Meeting

The inspector conducted an exit meeting on November 24, 1993, with members of the licensee staff as indicated in Section 1. During this meeting, the inspector summarized the scope of the inspection activities and reviewed the inspection findings as described in this report. The licensee acknowledged the inspector's findings. During this inspection,

the licensee identified as proprietary the 12 KV and 4 KV cable laboratory reports. None of the proprietary information is contained within this report.