U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos. 50-275/91-31 and 50-323/91-31

Docket Nos. 50-275 and 50/323

License Nos. DPR-80 and DPR-82

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1451
San Francisco, California 94106

Facility Name: Diablo Canyon Units 1 and 2

Inspection at: Diablo Canyon Site, San Luis Obispo County, California

Inspection Conducted: October 7-25, 1991, November 4, 1991, and December 6, 1991

Inspectors: F. Gee, Reactor Inspector
D. Acker, Reactor Inspector

Approved By: P. Narbut 12/16/91
P. Narbut, Acting Chief Date Signed
Engineering Section

Inspection Summary

Inspection on October 7 through October 25, 1991, November 4, 1991, and December 6, 1991 (Report Nos. 50-275/91-31 and 50-323/91-31)

Areas Inspected: Routine engineering inspection of engineering programs including the following areas: Design changes, a special risk assessment of the loss of direct current (dc) busses, followup of licensee corrective actions for a Switchboard 2G fire event and follow-up of previously identified items.

During this inspection, Inspection Procedures 37700, 37701, 62700 and 92701 were utilized.

Results:

General Conclusions and Specific Findings:

A Technical Specification accident monitoring instrument had failed and gone undetected for approximately two weeks. Failure of this instrument had also occurred in 1990. The current failure was not found by the licensee's routine surveillance program. The licensee's corrective actions from the first event, appeared to be inadequate.

The inspector noted an additional example of incomplete work. In this case the incomplete work observed was the absense of cover plate screws in junction boxes in the cable spreading room. These missing fasteners proved not be be of technical concern but are an example of poor workmanship which is not being noted and resolved by your problem identification systems. Previous examples have been identified in resident inspection reports.

Significant Safety Matters: None

Summary of Violations: None

Open Items Summary: Four LERs, 1 unresolved item and 1 follow-up item were closed. Two items were opened.

# DETAILS

1. Persons Contacted

Pacific Gas and Electric Company

*J. Townsend, Vice President and Plant Manager
*S. Fridley, Director, Operations
*W. Barkhuff, Director, Quality Control
*D. Miklush, Manager, Operation Services
*W. Rapp, OSRG Chairman
*B. Giffin, Manager, Maintenance Services
*J. Shoulders, NECS Onsite Project Engineer
*C. Dougherty, Senior Supervisor, QA
*R. Taylor, Senior Supervisor, QA
*J. Griffin, Regulatory Compliance, Senior Engineer
J. Bouchard, Regulatory Compliance
W. Crockett, Manager, Instrumentation and Control Maintenance
H. Phillips, Manager, Electrical Maintenance

*Denotes those attending the exit meeting on October 25, 1991.

The inspectors also contacted other licensee employees during the course of the inspection, including electrical and mechanical engineers, compliance engineers, quality assurance personnel, electrical maintenance personnel and instrumentation and control maintenance personnel.

2. Previously Identified Items

a. (Closed) LER 2-90-010-01, Inoperable Wide Range Reactor Cavity Sump Level Channels

On November 6, 1990, the licensee identified that both wide range containment reactor cavity sump level channels for Unit 2 had been inoperable since August 21, 1990, in violation of Technical Specification (TS) 3.3.3.6.a and 3.3.3.6.b. On August 21, 1990, operators had identified a potential problem with the safety parameter display system (SPDS) path containing the sump level channels. However, the operators had apparently not recognized that the channels had failed. In addition, monthly surveillance checks of the channels apparently did not identify that the channels had failed.

The licensee investigated the problem and repaired the channels. Extensive troubleshooting did not identify the cause of the failure of channel number 942. The licensee trained operations personnel on the meaning of the SPDS indication for failed channels. Training was accomplished by Operations Shift Orders AP C-151 dated August 13, 1991.

The inspector entered the control room on October 22, 1991, and asked operations personnel to select the Unit 2 SPDS channel containing the reactor cavity sump wide range level channels. The value shown on the SPDS for this sump level was "64 ?". Operations personnel looked at the actual cavity sump level indicators and reported to the inspector that both channels were correctly reading expected reactor cavity sump level. Two of the operators discussed what the "?" on the SPDS meant and referred the inspector to the Shift Technical Advisor (STA) for the meaning. The inspector concluded that the two operators appeared to be uncertain as to the meaning of the "?". Operations Shift Orders AP C-151 stated that a "?" after a SPDS reading indicated 1 of 2 channels to a Critical Safety Function (CSF) was off-scale or questionable.

The inspector discussed the SPDS reading with the STA and an Senior Reactor Operator (SRO). Both correctly identified the meaning of the SPDS "?". The SRO sighted the reactor cavity sump level indicators with the inspector, identified channel number 942 as potentially off-scale low and initiated action to have the channel evaluated. The inspector discussed the "?" on the SPDS with additional operations personnel. These additional personnel appeared to understand the meaning of the SPDS "?".

Instrumentation and Control personnel determined that channel 942 had failed low. The channel was deenergized and reenergized. As a result, the channel returned to normal operation.

The inspector entered the Unit 2 control room on October 23, 1991, and noted that Unit 2 channel number 942 appeared to have failed low again. Actions were again initiated to evaluate the channel. The channel was determined to have failed again. The channel indication returned to normal before a specific cause of the failure could be determined.

The inspector noted that the normal operating indication for reactor cavity sump wide range level and a failed channel indication could not be readily distinguished. This was because the electrical zero point was approximately the same as the mechanical zero point on the level indicator. The level signal was recorded on slow moving chart paper. A review of the chart paper indicated that channel 942 had probably failed low on October 10, 1991.

The inspector reviewed surveillance requirements associated with the SPDS. No specific check of the SPDS for failed or questionable CSF channels could be found.

The inspector considered that; 1) reactor cavity sump level channel 942 was subject to intermittent failure from unknown cause; 2) channel failure could not be readily identified by looking at the indication; 3) monthly surveillances of the reactor cavity level channels did not identify failed channels and; 4) the SPDS indication which could identify the failed channel was not being routinely monitored.

Based on the above information the inspector concluded that adequate controls did not exist to ensure that reactor cavity sump wide range channels remained operable in accordance with TS requirements. The inspector also concluded that the licensee's root cause evaluation was inadequate because the evaluation did not address the issue of undetected failures of the channel. Cavity sump level channels could again fail and not be identified for a long period of time. The inspector discussed these concerns with the licensee. The licensee reviewed these concerns and concluded that a daily surveillance which monitors all SPDS Critical Safety Function channels was needed. The licensee committed to prepare and perform this surveillance. Although not a safety system the SPDS provided failure information for a number of TS instruments, including failures which might not be discovered by other routine surveillances. In addition, to ensure that operators understood the meaning of SPDS failure indications, the licensee committed to install labelplates identifying failure indications on each SPDS monitor. The licensee was continuing actions to determine the cause for the intermittent failure of channel 942.

LER 2-90-010-01 is considered closed based on the issuance of a superseding LER which will result in further investigations of the cause of the intermittent failures of Unit 2 reactor cavity wide range level channel number 942. On November 21, 1991, the licensee issued LER 2-91-010 based on the repeat event of October 22, 1991. The licensee recognized the ineffectiveness of their original corrective action and committed to issue an LER supplement when the root cause was identified. The apparent failure of the licensee to take effective corrective action is considered an unresolved item pending the licensee's determination of root cause. (Unresolved Item 50-323/91-31-01).

b. <u>(Closed) LER 2-90-010-00, Inoperable Wide Range Reactor Cavity Sump Level Channels</u>

This LER is closed and the outstanding actions carried under Unresolved Item 50-323/91-31-01 as discussed in Section 2a.

c. <u>(Closed) LER 2-88-027-00 and (Closed) LER 2-88-027-01, Failure to Meet Technical Specification 3.7.9.4 Due to Failure of Two Fire Dampers to Close and Late Issuance of the Report Due to Personnel Error</u>

On November 27, 1988, with Unit 2 in Mode 4, Technical Specification 3.7.9.4 was not met due to a failure to implement a continuous fire watch within 1 hour when the halon fire suppression system became inoperable.

On November 23, 1989, during surveillance testing, 2 of 4 fire dampers for the solid state protection system (SSPS) room failed to close on manual actuation of the halon system. Failure of the 2 dampers to close was due to the fusible links not functioning as required. It was conservatively assumed that the dampers had been inoperable since the previous successful surveillance on November 18, 1988.

Failure of 2 of the 4 fire dampers could have resulted in dilution of the halon discharge to below the required concentration. The licensee noted that the report was issued late due to personnel failing to recognize that failure of the dampers to close could affect the operability of the halon system.

The licensee was unable to identify the cause of the failures. During the review the licensee identified that improper installation of an S-hook could cause the dampers to hang up when the S-hook was installed with the lower opening of the S-hook facing the damper. The licensee reported that the S-hooks were properly installed. Since the root cause of the problem could not be found the licensee changed the surveillance interval for these dampers from 2 years to 6 months for a minimum of 2 years. In addition the licensee trained appropriate personnel on the criteria to be used in reviewing surveillance test results for potential reportability.

The activities discussed in this section involved apparent or potential violation of NRC requirements identified by the licensee for which appropriate licensee actions were taken or initiated. Consistent with Section V.G. of the NRC Enforcement Policy, enforcement action was not initiated by Region V. The licensee discovered these occurrences during detailed records review resulting from a separate occurrence reported in LER 1-90-18.

The inspector reviewed the records of this LER with the licensee and sighted 2 SSPS room dampers. The dampers appeared to be properly assembled. The licensee's corrective actions appeared to be adequate.

Both the original LER and Revision 1 are closed.

d. (Closed) Followup Item 50-275/90-27-02, Improper Assembly of Cutler Hammer Powered Type R Relays

On November 27, 1990, the licensee identified that model D40 Cutler Hammer Powered Type R relays were not assembled in accordance with the vendor's instructions. Model D40 relays were used in many Class 1E systems throughout both Units.

Model D40 relays could be purchased with separate normally open (NO) and normally closed (NC) contacts. The NO and NC contacts could be installed by the purchaser to suit the requirements of the particular application. The vendor's instructions noted that for proper relay performance, it was imperative that contact mounting positions and sequence of mounting be strictly observed.

The vendor instructions required that NC contacts be installed in relay contact positions 1 through 5, with the first NC contact installed in position 1, the second NC contact installed in position 2, and continuing in sequence with a maximum of 5 NC contacts. The NO contacts were to be installed from positions 7

through 1, with the first NO contact installed in position 7, the second NO contact in position 6, and continuing in reverse sequence with a maximum of 7 NO contacts. Positions 6 and 7 were keyed to preclude installation of NC contacts without use of excessive force. Positions 1 through 5 would accept either NO or NC contacts.

During investigation of a failed model D40 relay the licensee identified that the relay was not assembled with contacts in the sequence required by the vendor. The licensee subsequently identified over 100 model D40 relays which were not assembled with the contact sequence required by the vendor's instructions. Five relays, 3 spare and 2 installed, were found with NC contacts forced into either position 6 or 7.

The licensee requested vendor review of the assembly method used by the licensee. The vendor noted that testing indicated that under no circumstances would a D40 relay fail to function due to mis-configured contacts. The vendor noted, however, that; 1) the contact response time may differ in a mis-configured relay, in an extreme case, contacts may take 100 milliseconds to operate; 2) the maximum field strength to respective poles may not be assured, making the relay less immune to external magnetic fields and; 3) reliable operation of relays with NC contacts forced into positions 6 or 7 could not be assured.

The licensee reviewed all the circuits associated with model D40 relays and concluded that a 100 millisecond delay would not affect plant safety.

The licensee sighted the installation of all model D40 relays and determined that only 2 relays would be subject to external magnetic fields. The licensee committed to a formal evaluation of these 2 installations.

The licensee determined that the NC contacts forced into positions 6 and 7 were all spare contacts. The licensee removed these contacts. The licensee determined that these relays were not damaged.

The licensee and the vendor determined that the original model D40 relay failure was not caused by contact arrangement. The licensee researched plant records and found no model D40 relay failures associated with contacts failing to operate.

The inspector reviewed the licensee's actions to date, the licensee's committed actions, the design of the model D40 relays and the vendor's conclusion that improper contact arrangement would not affect relay operation. The inspector concluded that the licensee's completed and continuing actions were adequate to ensure proper relay operation.

This item is closed.

e. <u>(Closed) Unresolved Item 50-275, 50-323/91-07-03, Final Safety Analysis Report (FSAR) Does Not Contain Accurate Emergency Diesel Generator (EDG) Loading Data</u>

The Electrical Distribution Functional Inspection team identified that the licensee's FSAR did not include accurate EDG loading data.

The licensee provided updated EDG loading data in FSAR Revision 7 dated September, 1991. The inspector reviewed the updated FSAR and considered that the EDG motor loading data had been correctly updated.

This item is closed.

No violations or deviations were identified in the areas reviewed.

3. <u>Design Changes</u>

The inspector reviewed the progress being made on the sixth diesel generator project. The inspector walked down the work areas with licensee personnel. The inspector reviewed quality assurance and quality control involvement in the project. Quality assurance personnel appeared to be closely monitoring all construction activities. Quality assurance personnel were also issuing a quarterly report which detailed work progress, areas monitored and findings. No problems were noted in the areas reviewed.

The inspector reviewed Design Change Notices (DCNs) DC2-EE-42605, Revision 0, dated June 29, 1989, and 2-EE-42117, Revision 3, dated April 4, 1991. Both of these DCNs replaced pneumatic Agastat timing relays with Agastat ETR solid state relays in Class 1E circuits. The licensee indicated that these changes were being accomplished due to drift problems with the pneumatic relays. The solid state relays were less sensitive to ambient temperature variations. Field Change E-15571, Revision 0, dated August 26, 1991 noted that DCN DC2-EE-42605 had specified AC coils in lieu of the required DC coils. The inspector noted that an evaluation process existed for design errors and was followed for determination of the cause of this error. The inspector sighted the installation of some of the new ETR relays. The inspector reviewed the qualification documentation for the new relays. No problems were noted in the areas reviewed.

The inspector reviewed the progress on the DCPs associated with replacement of plant radiation monitoring equipment. The inspector sighted cable, cable tray and conduit installed for this project. No problems were noted in the areas reviewed.

No violations or deviations were identified in the areas reviewed.

4. Maintenance Program

The inspector sighted Unit 1 Class 1E electrical equipment areas. Cleanliness was adequate. The inspector noted that a number of Class 1E branch junction boxes in the Unit 1 cable spreading room were missing 1 or more cover screws, including 1 box with no cover screws and several boxes with only 1 cover screw. The licensee installed the missing screws. Although the uncomplete work did not represent a safety concern, the licensee was reminded that this was another example of poor workmanship that has been the subject of resident inspection reports and deserves management attention.

No violations or deviations were identified in the areas reviewed.

5. Review of Risks Associated with Loss of Direct Current (dc) Safety-Related Buses

During a recent individual plant examination (IPE) being performed by another licensee, an increased core melt frequency was identified with loss of a safety-related dc bus. The inspector reviewed the status of the IPE being performed at Diablo Canyon and the impact on a Unit of loss of a safety-related dc bus. The results of this review are summarized in the following paragraphs.

Diablo Canyon had completed its IPE associated with dc buses. The loss of a DC bus was found to be not a significant risk. In addition, Diablo Canyon had reviewed the other licensee's IP's and concluded that design differences made loss of a dc bus at Diablo Canyon a much lower risk frequency event. The inspector reviewed the licensee's IPE and concurred.

The licensee issued Abnormal Operating Procedure OP AP-23, Revision 0, dated April 21, 1989, "Loss of Vital DC Bus." This procedure identified what safety equipment would be lost for each dc bus failure and specified plant control actions. The inspector reviewed this procedure and concluded that it was adequate.

Based on the areas reviewed, the inspector concluded that loss of a DC bus was not a high risk event at Diablo Canyon.

No violations or deviations were identified in the areas reviewed.

6. Unit 2 Vital Bus G Fire

On October 2, 1991, during the performance of emergency diesel generator (EDG) testing, an electrical fire occurred in an associated 480 volt alternating current (ac) switchboard. The testing being performed involved starting EDG 2-1 and observing that emergency loads supported by that EDG were acceptably energized.

EDG 2-1 supported 480 volt ac vital bus G. Bus G was intentionally deenergized and the EDG start commenced. Containment Fan Cooling Units (CFCU) 2-5 and 2-3 were part of the bus G loads. Immediately after bus G was energized a ground alarm energized. Later, when CFCU 2-3 started, smoke and flame were observed at the switchgear.

The fire alarm was sounded and the fire brigade dispatched to the area. The CFCUs were manually stopped and bus G was deenergized. The licensee investigated the problem and concluded that the fire was due to a phase to phase fault on the line side of CFCU breaker number 52-2G-01R. The following paragraphs provide an analysis of the fault, the corrective and investigative actions taken and the root cause conclusions.

a. Analysis of the Fault

A loose connection was considered to have existed on CFCU breaker number 52-2G-01R where a small piece of bus bar connected to the line side breaker terminal. This loose connection was a source for heat build up which eventually arced and ionized the surrounding air. The ionization broke down the dielectric strength of the air and provided a ground path for the arc to strike. This created a ground fault. Since the 480 volt ac system was ungrounded, a single ground fault did not cause an immediate problem. With one ground fault already existing in the compartment, a second phase to ground fault occurred when CFCU 2-3 was started. This second ground fault created a phase to phase fault which was cleared by vaporization of bus pieces.

b. Corrective and Investigative Actions

The licensee inspected and tested EDG 2-1 and the associated electrical distribution system for additional damage. No additional damage was found. The licensee replaced the damaged bus bars and CFCU circuit breaker.

The licensee determined that the connection between the breaker and the bus piece was made by threading a steel bolt into the soft copper bus bar. No torque value was given in the licensee and vendor procedures for this connection. A washer was required to be installed under the head of the bolt. There was little clearance behind the bus piece, although insulating paper appeared to have been required to have been installed. The licensee concluded that if the washer were omitted the bolt could have protruded through the bus piece and been very close to grounded metal structures. The absence of insulating paper could also have contributed to a ground fault. The immediate area of the fault was too heavily damaged to determine the actual status of the washer and insulating paper.

The licensee had previously recognized that threading of steel bolts into soft copper bus pieces was not an optimum design. Just prior to the fire the licensee had made a design change to the load side connections to the CFCU breakers. This work was done with the line side connections still energized. The procedure did not require the line side connections to be retightened after the load side work was completed.

The licensee concluded that connections with steel bolts threaded into copper bus pieces would be changed by drilling out the bus piece and installing a bolt, nut and locking device for all large loads. The licensee will also develop a thermography program to minimize recurrence of electrical faults.

c. Root Cause

The licensee concluded that the root cause was a loose connection or that washers had been left out, thus reducing the required clearances from ground.

The licensee noted that the connections may not have been properly tightened when they were originally made. The licensee noted that the connection design was adequate, but could be improved.

The inspector reviewed the licensee's actions and evaluations. The inspector also witnessed replacement of threaded bus pieces with nuts and locking devices for line side CFCU breaker connections.

The inspector considered that the licensee had accomplished adequate testing to ensure that no damage occurred to EDG 2-1 and the associated distribution equipment. The inspector also considered that the licensee's action to replace selected connections was prudent.

The inspector considered that the root cause identified by the licensee may not have identified all the potential contributing causes. The inspector noted that modification of the load side CFCU breaker connections could easily have required the technician performing the work to have exerted force on the CFCU breaker to obtain proper connection of the large load side cables. This force could have loosened the line side connections. The inspector considered that since the fault occurred immediately after the load side work was accomplished that the licensee's root cause should have considered the adequacy of the work procedure and performing personnel. The inspector discussed this issue with the licensee. The licensee considered that there was no personnel error in the load side work. The licensee acknowledged that the procedure which modified the load side connections without checking the line side connections for tightness may have been a contributing root cause for the fault. The licensee agreed to consider the procedure adequacy for future electrical bus connection work. Therefore, the inspector considered that the root cause evaluation and associated corrective actions were adequate to minimize the potential for future bus faults.

The inspector also reviewed 480 volt ac and 125 volt direct current (dc) switchgear maintenance procedures to ensure that an inspection for loose bus connections and signs of overheating was being routinely accomplished. An inspection of bus connections was included in routine 480 volt ac switchgear maintenance procedures. Standing work orders for routine maintenance of 125 volt dc switchgear included cleaning but contained no specific inspection for loose bus connections and signs of overheating. The inspector provided this information to the licensee. The licensee committed to modify the standing work order to include an inspection for loose connections and signs of overheating.

The inspector concluded that the licensee's entire response to the fault was adequate.

7. Adequacy of the Design Change Package on Containment Recirculation Sump Level Instrumentation (37700,37701)

Background

The inspector followed up on an examination of a design change which had been examined, in part, in Inspection Report No. 50-275/91-11. The design change involved a change in the level instrumentation installed in the containment recirculation sump. This sump is an important emergency core cooling feature which comes into play after a loss of coolant accident. The specific design change was DCP J-41715 and involved the installation of a thermal dispersion type level sensing instrument replacing a bellows type instrument.

The inspector had questions, in the previous inspection, regarding the assumptions made by the licensee's Operations Department in their emergency operating procedure. The operations procedure writers had assumed certain instrument accuracies which could not be substantiated by engineering personnel. It was apparent to the inspector that there was some degree of inadequate communication between operations and engineering on this matter. This was identified to licensee management at the previous exit interview.

This inspection

The inspector found through records review and personnel interview that the required accuracy and actual accuracy had not been fully resolved by the licensee's engineers.

The design change has been completed and the instruments have been in service for approximately six months.

The inspector considered that the licensee's performance specifications for the instruments were not sufficiently detailed or precise. Specifically the specifications could have but did not state the required post-accident channel accuracy of the level instrumentation or the required instrument time response characteristics. The licensee provided a qualification test report for post-accident accuracy which indicates the accuracy was comparable to the pre-accident accuracy. After the review, the inspector concluded that the post-accident channel accuracy appeared to be adequate.

Regarding instrument time response, the inspector raised the question of the possible detrimental effects of boric acid deposits on the thermal dispersion type level device. The inspector pointed out that time response might be affected.

The inspector independently verified that the instrument time response appeared to be adequate based on expected level rise times and vendor information.

The inspector explained at the exit interview that the absence of more detailed performance specifications for these instruments reflected itself in apparent test requirement confusion. Several revisions of test requirements were made to revise the requirement for accuracy.

Conclusion

No safety concerns were identified and the installed instruments appear capable of performing their functions.

The communications between operations and engineering appears to deserve attention in that pertinent questions on the part of operations were not answered in a timely way.

The performance parameters for this instrument could have been more detailed in regards to post-accident accuracy and time response requirements.

The licensee acknowledged these conclusions and committed to examine the occurrences for potential program improvements.

No violations or deviations were identified.

8. Conax Containment Penetrations

The inspector reviewed Design Change Package J-44372 for penetrations 21E and 39E. The design change was issued to relocate the pressure indicator, which was mounted on the head flange of the existing Conax penetration, to a location on the exterior wall of the containment and outside of the penetration enclosure box to facilitate maintenance activities. The pressure indicator and its associated valve were instrument Class II. This pressure indicator monitored the pressure in the space between the inboard and outboard resilient seals.

The inspector walked down the installation and verified the work order for Quality Control signatures.

No violations or deviation were identified.

9. Electrical Independence

During the walkdown of a Design Change Package (E-44804), the inspector observed that the Class 1E and Non-Class 1E circuits were going through the same Conax penetration. The inspector also observed cables from different electrical divisions were going into the same junction box. The inspector observed that two blue banded conduits and one yellow banded conduit (KT105) were connected to Junction Box BTG10E. Four conduits with no color designation and one red banded conduit were connected to Junction Box BTG4E. At Diablo Canyon, the safety related Class 1E circuits were divided into four protection sets. The colors of red, white, blue, and yellow corresponded to the four protection sets respectively. The Non-Class 1E cable had no color designation. Under certain conditions at Diablo Canyon, it is permitted to run different divisions and Non-Class 1E cable in the same penetration.

The licensee noted that there are many existing penetrations with Class 1E and Non-Class 1E cables. The licensee indicated that there is no case where redundant circuits are going through the same penetration.

The licensee cited the Design Criteria Memorandum (DCM) E-15, Revision 3, as the design criteria for selection, separation, isolation and installation of cable and wire for Diablo Canyon. The DCM stated that mutually redundant circuits shall not be routed in the same containment penetration. Non-Class 1E circuits may be routed in the same containment penetration as Class 1E circuits if single failure criteria is met.

In the DCM, the licensee stated that Diablo Canyon was not committed to Regulatory Guide 1.75 separation requirements, except where explicitly stated. However, the licensee also stated that Regulatory Guide 1.75 should be used for design guidance where feasible on new designs.

The Design Change Package E-44804 was to replace a General Electric penetration with a Conax penetration. The licensee considered that the separation of 1E and non-1E circuits was not feasible and explained that all Non-Class 1E cables in the penetration being replaced were coaxial cables. The coaxial cables required coax feedthroughs in the penetration and there were no spare coaxial feedthroughs in any existing penetrations. This according to the licensee made it unfeasible to separate the Non-Class 1E cables.

The subject of electrical independence was raised in Inspection Report 91-11 (Reference: Unresolved Item 50-275/91-11-01). The Diablo Canyon licensing requirements regarding the electrical independence are being reviewed. The observations on electrical independence made during this inspection will be evaluated in conjunction with followup item 50-275/91-11-01.

10. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. An unresolved item disclosed during this inspection is discussed in Paragraph 2.a of this report.

11. Exit Meeting (30703)

On October 25, 1991, an exit meeting was conducted with the licensee representatives identified in Section 1. The inspectors summarized the inspection scope and findings as described in this report.

The licensee acknowledged the inspection findings and noted that appropriate corrective actions would be implemented where warranted. The licensee did not identify as proprietary any of the information provided to the inspectors during this inspection.

Subsequent telephone conferences were held on November 4, December 6 and December 11, 1991 to clarify technical points with the licensee.