U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/86-29 and 50-323/86-27

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: September 28, 1986 to November 8, 1986

Inspectors: ---------- for 11/13/86
M. L. Padovan, Resident Inspector Date Signed

---------- for 11/13/86
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Approved by: ---------- 11/13/86
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Summary:

Inspection from September 28, 1986 through November 8, 1986 (Report Nos. 50-275/86-29 and 50-323/86-27)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, followup of onsite events, open items, and LERs, as well as selected independent inspection activities. Inspection Procedures 30703, 60710, 61701, 61726, 62703, 71707, 71710, 71711, 90721, 92700, 92702, 93702, 94703, and 86700 were applied during this inspection.

Results of Inspection: One apparent violation was identified in the area of procedure compliance dealing with operations control of system operability during snubber testing (paragraph 5.). Another potential violation was identified dealing with ineffective corrective action in the area of containment airlock door operability (paragraph 6.) which will be the subject of separate correspondence.

DETAILS

1. Persons Contacted

J. D. Shiffer, Vice President Nuclear Power Generation
*R. C. Thornberry, Plant Manager
*J. A. Sexton, Assistant Plant Manager, Plant Superintendent
*J. M. Gisclon, Assistant Plant Manager for Technical Services
*J. D. Townsend, Assistant Plant Manager for Support Services
*C. L. Eldridge, Quality Control Manager
*K. C. Doss, Onsite Safety Review Group
*R. G. Todaro, Security Supervisor
*D. B. Miklush, Maintenance Manager
*D. A. Taggert, Director Quality Support
*T. J. Martin, Training Manager
*W. G. Crockett, Instrumentation and Control Maintenance Manager
*J. V. Boots, Chemistry and Radiation Protection Manager
*L. F. Womack, Operations Manager
*T. L. Grebel, Regulatory Compliance Supervisor
S. R. Fridley, Senior Operations Supervisor
R. S. Weinberg, News Service Representative
D. A. Malone, Senior I&C Supervisor

The inspectors interviewed several other licensee employees including Shift Foremen (SFM) reactor and auxiliary operators, maintenance personnel, plant technicians and engineers, quality assurance personnel and general construction/startup personnel.

* Denotes those attending the exit interviews on October 10, 24, and 31, 1986.

Note: Acronyms are used throughout this report; refer to the Index of Acronyms at the back of the report.

2. Operational Safety Verification

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 Specification (TS). Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions, and trends were reviewed for compliance with regulatory requirements. Shift turnovers were observed on a sample basis to verify that all pertinent information of plant status was relayed. During each

week, the inspectors toured the accessible areas of the facility to observe the following:

(a) General plant and equipment conditions.

(b) Fire hazards and fire fighting equipment.

(c) Radiation protection controls.

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

(e) Interiors of electrical and control panels.

(f) Implementation of selected portions of the licensee's physical security plan.

(g) Plant housekeeping and cleanliness.

(h) Essential safety feature equipment alignment and conditions.

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

a. Unit 1 Containment Penetration Isolation (Engineered Safety Features (ESF) System Walkdown)

The inspector verified manual containment isolation valves outside of containment were properly positioned, sealed or controlled to assure containment isolation during core alterations. Further discussion of this item is provided in the Unit 1 refueling section of this report.

No violations or deviations were identified.

3. Onsite Event Followup

a. Tilted Fuel Assembly

On October 1, 1986 during refueling operations, fuel assembly A06 was found by the oncoming shift to be tilted from its normal upright position and leaning against the core baffle plates (about 10 degrees). The cause of the condition was that the previous crew had lifted the assembly slightly to properly set alarm points on the load cell for assembly A06, the first rodded assembly being removed. The assembly had bowed, which is common, and subsequently when the assembly was lowered, it did not re-engage the core support plate pins. The assembly was upright when the crew left and apparently fell over during crew change. No radiation release was observed by airborne monitors or sampling of the refueling cavity water.

The licensee initiated a recovery plan in a organized and methodical fashion which included review by Westinghouse (the reactor vendor) and the NRC.

A recovery procedure was written, special tooling was devised, manufactured, and tested and mockup training was provided for the recovery crew.

The inspectors observed the training of the crew and the recovery operation.

The recovery was completed at about 3:30 a.m. on October 3, 1986 with the fuel assembly transported to the up ender assembly. Normal refueling operations resumed at that time.

b. Inadvertent Diesel Generator Start

On October 2, 1986 an electrician inadvertently shorted a bus potential fuse causing an automatic transfer of 4 kv power and a diesel generator start. Unit 2 LER 86-25 documents the cause and corrective action.

c. Unit 1 Pipe Snubbers Mistakenly Removed

On October 4, 1986 the licensee discovered that two piping snubbers had been mistakenly removed from the charging system in Unit 1. The charging system was necessary as a boration flow path for refueling operation at that time.

The mistake was caused by an error in the line designation list for the snubbers. They were listed to be on the letdown system but were in fact on the charging system. The listing error was apparently due to the fact that the charging system piping is connected, in the area of the snubbers in question, to the letdown heat exchanger.

The licensee prepared a nonconformance report DC1-86-OP-N119 and appears to be taking appropriate corrective action. The charging system was subsequently analyzed by the licensee and determined to be operable during the time the snubbers were removed.

The resident followup of this event led to the discovery of a related apparent violation as discussed in paragraph 5.

d. Water Spill in the Residual Heat Removal (RHR) System

On October 12, 1986 a water spill occurred in Unit 1 from the piping associated with the RHR low pressure relief valve, which had been removed. The problem was apparently caused by not having drained all the lines within the work clearance boundary. When a second work clearance was authorized within the original boundary, a valve was opened causing the spill.

This item will be followed as discussed in paragraph 3. j. of this report.

e. Water Spill from Safety Injection (SI) Vent Valves

On October 15, 1986 there was a water spill from the Unit 1 SI vent valves apparently due to valve lineup errors. Operations personnel had been preparing the RHR system for return to service and had completed the RHR system valve lineup. The flowpath valves associated with the SI system had not all been checked however resulting in the spill from open vent valves.

This item will be followed up as discussed in paragraph 3. j. of this report.

f. Incorrect Power Supply to Protection Set IV Indication

On October 25, 1986 at about 0325, an error in switching electrical breakers resulted in the loss of normal control room lighting, and revealed that the power supply to protection set IV bistable position indications was incorrect. The licensee determined that a jumper was installed which provided power for the bistables from an "interruptable power" supply. This jumper was installed to provide power for testing of inputs to the Safety Parameter Display System for the protection set IV bistable position indication. This jumper did not impact safety function, but did impact the reliability of control room indication of the protection system functions.

The jumper had been installed prior to Unit 1 operation on August 20, 1983 in accordance with Electrical Department Procedure, ETI-4-2 "Recalibration, Maintenance and Surveillance Testing of Plant Process Instrumentation." This procedure only required documentation of jumpers on instrumentation released to startup; however for in-process work that was not turned over to startup, as was the case for this work, it was the practice and consistent with construction procedures to simply fill and hang an Information Tag. The fact that a jumper could have been installed without a tracking system could have resulted in uncontrolled jumpers, as was the case for this event, and is considered a deficiency by the inspector. This deficiency in the licensee's program to control jumpers has been corrected by the current Project Instruction 51, "Temporary Modifications," which requires documentation of jumpers in the Temporary Modification Log maintained in accordance with Nuclear Plant Administrative Procedures C-4 and C-4S1.

The inspector reviewed the testing that was performed for the connection of the Protection Set IV to the Safety Parameter Display System. The testing verified the inputs correctly responded, but did not verify the power supply connections. For the installation of the Safety Parameter Display System this testing seemed acceptable.

The licensee's corrective actions included walkdowns of the control room panels and Hagen racks which assured correct wiring terminations and system descriptions. Additionally, the licensee has performed similar walkdowns on the 4 KV power system in response

to a previous event. The licensee has also instituted a program for the Shift Technical Advisor to audit the jumper log on a weekly basis which according to the onsite quality organizations has greatly improved the jumper log. Finally the licensee has a program to convert long-term temporary modifications to design changes to assure Engineering Department review and that plant drawing appropriately reflect system configuration (This program was in response to input from the Institute for Nuclear Power Operations, and the licensee's Quality Assurance and Quality Control organizations).

The inspector reviewed observations by the Quality Assurance and Quality Control organizations related to jumpers. There were a substantial number of findings in this area and also a number of revisions to Nuclear Plant Administrative Procedure C-4S1. The quality organizations indicated that the revisions were responsive. The inspector's review of the quality organizations observations found that problems continue to recur and the licensee continued to address the problems as they occur. The licensee was informed at the exit that continued attention in the jumper area was advised and this will be followed up in the normal course of future inspections in this area.

g. Unauthorized Work on Main Feed Control Valve, Unit 2

On October 26, 1986 a main feedwater control valve stem packing was tightened by a contract mechanic without proper work authorization and approval. The valve, FCV 520, has a technical specification stroke time requirement. The apparent errors leading to the improper work were that the work planner did not invoke proper instructions and the mechanic did not follow instructions given.

The operations personnel immediately noted the packing adjustment through the response characteristics of the flow control valve and then had the packing reloosened to restore the control characteristics.

The licensee prepared a nonconformance report and appears to be taking appropriate corrective action.

h. Degraded Main Steam Non-return Check Valves, Unit 1

On October 28, 1986 the licensee discovered that the mainsteam non-return check valves in Unit 1 were degraded. Specifically, the nut which holds the disk to the hinge arm was missing on one valve; however, the disk had not separated from the hinge arm and the valve was found properly sealed. In another valve, the nut had backed off about halfway. The remaining two valves were satisfactory.

The licensee had performed the visual inspection of the valves as part of the inservice test program. The valves were initially examined using an optical device through a drain hole in the bottom of the valve.

The licensee initiated an closer examination of the valves and the similar main steam isolation valves through disassembly of the top bonnet covers.

The licensee discovered that the stainless steel locking pins which are to secure the nuts in place had worn on some nuts and apparently worn through on the failed valves.

The NRC determined that a similar problem had been discovered at the Zion power plant a few months earlier when a check valve disk had in fact become disengaged from its hinge arm during power operations which was immediately obvious from changes in plant parameters. Zion has similar valves to these installed at Diablo Canyon.

The inspectors assured themselves that Operations personnel were aware of the Zion occurrence and had briefed the operators. Additionally, the licensee embarked on a program of radiography of the Unit 2 check valves to verify the proper assembly of the valves. On November 10, 1986 the presence of the Unit 2 nuts and pins were verified using a portable linear accelerator to achieve the penetration and resolution required for a satisfactory radiograph.

The question of additional verifications required for continued long-term operation of Unit 2 has been referred to NRC headquarters for more in-depth technical review. Unit 2 is scheduled for shutdown in April 1987 when a similar visual inspection of the valves can be performed.

i. <u>Leaks in the Safety Injection Accumulators, Unit 2</u>

On October 28, 1986 during containment entry at power, the licensee discovered minor weepage leaks in the base metal of socket weld fittings which form the drain penetrations in the bottom of the accumulators.

The leaks were in accumulators 2-2 and 2-4. The licensee had specifically looked for leaks at these points on a three month basis because minor leaks had been discovered in accumulators 2-1 and 2-3 in late 1985 (and corrected) and subsequently in February 1986 another minor leak had been discovered in Accumulator 2-2 (and corrected).

The appearance of new weepage raises questions regarding the quality of vendor work on the accumulators.

The licensee has contacted the supplier who stated that the main girth welds on the accumulators had been radiographed for quality at construction, that no other utilities with accumulators from the same vendor have had reported problems, that Diablo Canyon is somewhat unique in that the small piping (from the drain connection to the accumulator skirt) is ordinarily installed by the field but in Diablo Canyon's case was installed by the vendor.

Licensee management has committed to reassure that the quality of the accumulators is satisfactory (Followup Item 50-323/86-27-01).

[illegible]

j. Steam Generator (S/G) 1-3 Overfill and Inadvertent Pressurization

On October 30, 1986 operators on the graveyard shift began refilling S/G 1-3 which had previously been drained and opened in order to perform maintenance and inspection activities during the Unit 1 refueling outage. The demand controller for the 10 percent atmospheric steam dump valve (PCV-21) was set at the 10% open position to provide a vent path for the air as level in the S/G was increased. However, the operators were unaware that the manual isolation valve (V-1-3015) to PCV-21 was closed and thus blocked the intended vent path.

After shift turnover, operators on the dayshift continued to fill the S/G but had difficulty in reading the demand on PCV-21 and opened PCV-21 thinking a vent path was now positively established. Verification of the position of the manual isolation valve to PCV-21 was likewise not performed by the day shift operators. Upon reaching an indicated level of 80% on the S/G wide range recorder, the indicated level unexpectedly began to decrease. At 45% indicated level, operators stopped Auxiliary Feedwater (AFW) pump 1-3 and requested an Instrumentation and Controls technician investigate the apparent level decrease. With no further water introduction into the S/G, the level recorder indicated S/G water level was again increasing. At 65% level, operators could not locate any problems with the S/G, concluded the wide range level recorder was improperly functioning, restarted AFW pump 1-3, and dispatched personnel into the containment to monitor the level locally using an installed tygon tube. Upon starting the pump, indicated water level dropped to zero in less than 15 minutes. Operators then again stopped AFW pump 1-3, and began a second investigation into the cause of the unanticipated water level readings.

An operator, investigating outside containment, reported to the control room that manual isolation valve V-1-3015 was closed. The control room operator closed PCV-21 and V-1-3015 was then manually opened. Additionally, at that time, the control room operator noticed two S/G pressure channels indicated 900 psig (the other two channels were out of service) whereas the pressure indication should have been zero. PCV-21 was slowly opened from the control room. Pressure on the S/G decreased to zero, and after a volume of air was released water began passing through PCV-21. PCV-21 was then isolated, and steps were taken to drain the inadvertently filled section of the main steam line and a portion of the steam supply line to the turbine driven auxiliary feedwater pump.

Subsequent investigation of the wide range level indication system revealed another problem, specifically that the root valve from the lowest S/G level instrumentation connection was partially closed, which precluded accurate level indication. Operations had verified the valve to be open on October 24, 1986, but a valve repair work order was issued to repack the valve on October 25th. The valve was shut at this time, utilizing a generic valve packing clearance.

Operations believed all work had been completed on the valve, but maintenance had not reported off the generic clearance and additional valve work was still required.

Technical Specification (TS) Limiting Condition For Operation (LCO) 3.7.2.1 states "the temperature of both the reactor and secondary coolants in the steam generators shall be greater than 70 degrees F when the pressure of either coolant in the steam generator is greater than 200 psig." LCO 3.7.2.1 is applicable "at all times." This LCO assures that pressure induced stresses in the S/G do not exceed the maximum allowable fracture toughness stress limits. To evaluate compliance with this LCO, the licensee obtained S/G tube sheet temperature as indicated in Operating Procedure (OP) O-1 "Steam Generator/RCS Pressures at Low Temperatures ." Tube sheet temperature was measured to be 73.5 degrees F approximately two hours after the pressurization event. The licensee concluded the S/G was not overstressed since the S/G filled over a seven hour period, equalizing the tubesheet with the water temperature before the pressurization occurred.

The following good operating practices were not followed during the S/G overfilling/pressurization event:

Operators assumed the manual isolation valve to PCV-21 was in open position, which is an improper assumption during a refueling outage. Under refueling outage conditions, the position of the manual valve should have been verified locally prior to operating and relying upon PCV-21 to provide a vent path.

The root valve position to the S/G wide range level indication was not controlled after operations performed valve alignments to return the system to normal configuration.

When conducting plant evolutions, operators should monitor all available, relevant plant instrumentation. The two operable S/G pressure channel indicators displayed 900 psig and were located about four feet from the wide range level recorder on the control board.

During shift turnover, the day shift control operator, who was controlling S/G level, did not obtain the understanding that the intended S/G vent was through PCV-21. He assumed venting was being accomplished through the nitrogen system inside containment, and did not obtain verification of his assumption.

Part C of the applicable operating procedure (OP A-5:II "Preparing S/Gs for Startup") discusses refill of a steam generator following a dry layup. Part C indicates the steam generator should be vented by opening a 10% steam dump, but also specifies an additional vent, the S/G safety valves header high point vent, be opened. This action would have prevented pressurizing the S/G, but operators deviated from the S/G

preparation step of opening the valve. Either the procedure should have been followed, or a temporary change to the procedure should have been authorized prior to proceeding with refill of the S/G.

As short term corrective action, a Shift Foreman memo was issued by the Senior Operations Supervisor, applicable to the remainder of the refueling outage. The memo implemented an "Operational Controlled Systems List" delineating systems where valve alignments and operational status are known. Individual clearances (rather than generic clearances) will have to be issued when performing work on these systems. Walkdowns of systems not on the list will be required before filling, venting, surveillance or other types of operations on the systems.

Piping analysis was performed in the licensee's San Francisco office to determine the effect on the piping of filling the steam lines (relief valve header, steam line to Main Stem Isolation Valve (MSIV), and Terry Turbine line to the AFW pump) with water. The results indicated piping stresses and displacement were acceptable. Support hardware was also found to be unaffected.

The improper valve position control associated with the water spills described in paragraphs 3. d. and 3. e. on October 12 and 15 respectively; this event on October 30, 1986 (which involved improper valve position control and operator inattentiveness); the event of October 31, 1986 described in paragraph 3. k. (which involved improper valve position control); the event of November 1, 1986 described in paragraph 3. l. (which involved operations attentiveness) indicate a need for aggressive management corrective action. The lack of proper valve position control and operator attentiveness are considered an unresolved item (Unresolved item 50-275/86-29-01).

k. <u>Inadvertent Addition of Water to the Reactor Vessel</u>

On October 31, 1986 three feet of water were inadvertently added to the reactor vessel. At the time the reactor vessel water level was being maintained at mid loop level. A work clearance on the SI system was issued which resulted in returning a closed valve to its normal open position. This provided a flow path by gravity from the refueling water storage tank to the reactor vessel.

The licensee has written a nonconformance report (DC1-86-OP N131) on this and the steam generator overfill and pressurization (paragraph 3. j.). Corrective action will be followed as part of the unresolved item discussed in paragraph 3. j.

l. <u>Spent Fuel Pool Level Low</u>

On November 1, 1986 the water level of the spent fuel pool was recorded at 22' 11" at 2:00 a.m. by an auxiliary operator reading a pool side scale. The technical specifications require a minimum of 23'. At 5:50 p.m. that day a shift foreman reviewing that shifts

auxiliary operator log sheet noted the level was recorded at 22' 6", recognized the situation, and took corrective action.

Subsequent licensee investigation showed that the scale was purposefully installed 6 1/2 inches high in preparation for the intended use of the new high density racks which are 6 1/2 inches higher than the reinstalled low density racks. When the low density racks were reinstalled a conscious decision was made not to change the scale since it read conservatively high.

Therefore, the technical specification water level limit was not violated. However, the aspect of auxiliary operator knowledge and attentiveness to water level readings remains in question.

This aspect will be followed up in conjunction with the unresolved item of paragraph 3. j.

m. Unit 2 Runback

On November 7, 1986 Unit 2 experienced a runback to less than 50% power and almost experienced a turbine trip/reactor trip. The unit was run back due to loss of condenser vacuum. Vacuum was lost due to loss of turbine gland sealing steam which was lost because steam supply valve PCV-69 went shut. The Unit 2 valve shut because a mechanic performing a test in Unit 1 installed an electrical jumper on the wrong terminal causing a short, a blown fuse and a loss of power to the valve.

The licensee is investigating corrective action.

n. Emergency Borate Flow Channel Inoperability

The inspector also examined licensee action regarding an event which occurred during the previous reporting period. On September 17, 1986 with Unit 1 in Mode 5 (Cold Shutdown), Instrumentation and Controls (I&C) technicians were performing Surveillance Test Procedure (STP) I-57 "Calibration of Emergency Borate Flow Channel 113." During testing, it was discovered that the cable between the sensing head and transmitter for channel 113 had electrical leads that were miswired, rendering the instrument inoperable.

The licensee determined that when STP I-57 was last performed on April 1, 1985, two of the cable electrical leads were incorrectly wired at the conclusion of the procedure. On May 1, 1985, the unit entered Mode 3, and on May 8 exceeded the time requirement for the action statement of TS 3.3.3.5 due to channel 113 being inoperable. On September 17, 1986 Channel 113 was properly wired and returned to an operable status. During the period that Channel 113 was inoperable, instrumentation for monitoring other emergency boration flowpaths was available.

Circumstances leading up to miswiring flow transmitter (FT) 113 began when PG&E Design Engineering developed drawing 501725, which

provided a Diagram of Connections for installation of the transmitter. This included delineation of terminations and wire identifiers for the manufacturer's supplied cable between the transmitter and the sensor and reference to the manufacturer's instruction manual. In keeping with the guidelines specified in the Thermal Electric Design Standard (Drawing 334335), no reference was made to the manufacturer's recommended color code.

During the installation process, the installer (in keeping with PG&E standard practice) terminated the field wiring and the manufacturer supplied cable in accordance with the Diagram of Connections without regard to wiring color. This resulted in a discrepancy between the installed condition and the manufacturer's drawings.

In writing the Surveillance Test Procedure (STP I-57) for calibration of FT-113, it was assumed that the manufacturer's recommended color had been adhered to. Accordingly, only the manufacturer's drawings were incorporated in the STP as guidelines for the technician to perform the required determinations and reterminations during the calibration process.

During reinstatement of the channel to service following routine calibration on 4/01/85, the cable was terminated in accordance with the color coding of the manufacturer's drawing supplied in the procedure. This resulted in the channel being miswired and therefore inoperable from that time until the wiring discrepancy was rectified on 9/17/86.

As corrective action to prevent recurrence, the licensee proposed the following:

> When requested by Plant Engineering, General Office Engineering will revise Diagrams of Connection to include the manufacturer's recommended color coding. Notes on the drawings will indicate these additions are for human factors consideration only.
>
> Procedure writing guidelines will be revised to provide that in cases where wiring connections are determinated and reterminated during the performance of a test, reference will be made to the appropriate Diagram of Connections.
>
> STP I-57 is to be revised to reference the appropriate Diagram of Connections and provide adequate determination/retermination instructions.
>
> I&C will conduct training sessions concerning the use of Diagrams of Connection relative to field terminations.
>
> Use of Diagrams of Connection and making field wiring determinations and reterminations will be evaluated by the training department for inclusion into the New Hire Journeyman Orientation Program.

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 IV.A of the NRC Enforcement Policy, enforcement action was not initiated by Region V.

o. Late Notifications to the NRC

Two events occurred prior to this reporting period which involved late notifications to the NRC. These were temporary loss of containment integrity on August 30, 1986 and the temporary loss of RHR cooling on September 8. 1986.

The licensee has enhanced the training given to operations supervision to preclude recurrence.

The activity 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 IV.A of the NRC Enforcement Policy, enforcement action was not initiated by Region V.

4. Maintenance

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 maintenance activities were performed by qualified personnel, in accordance with fire protection and housekeeping controls, and replacement parts were appropriately certified.

Maintenance and repair activities examined during this reporting period included containment airlock doors, main feed control valve packing, main steam non-return check valves and safety injection accumulators.

No violations or deviations were identified except as identified elsewhere in this report.

5. Surveillance

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

Surveillance activities were examined in the areas of containment airlock doors, main steam non-return check valves, safety injection accumulator leak surveillance and calibration of the emergency borate flow channel 113.

Particular effort was expended in the examination of the complex surveillance of pipe snubbers performed for the Unit 1 refueling outage.

[illegible]

[illegible]

[illegible]

a. Complex Surveillance - Piping Snubber Functional Testing

Background As discussed in paragraph 3. c. of this report, on October 4, 1986 the licensee discovered two piping snubbers on the charging line had been removed for testing for greater than 72 hours. This problem was recorded on NCR DC1 86-OP N119 and was the subject of a 10 CFR 50.72 report to the NRC. No LER report was sent since the licensee determined the occurrence to be not reportable per 10 CFR 50.73. This decision was based on calculations which showed the piping to be operable with the snubbers removed.

The inspectors examined the licensee's corrective action to the NCR and found it acceptable.

As a follow-up to this event the inspectors examined the snubber surveillance testing program.

Snubber Testing Results

The licensee is required to sample snubbers in each piping system on a periodic basis. If the results are unsatisfactory,the sample is to be expanded. On Unit 1, the sample results were unsatisfactory which led to increased sampling. The failures were largely due to marginally excessive drag forces (to move the snubber mechanism). The licensee's actions in response to failed snubbers was found to be in conformance with the technical specification sampling requirements.

The cause of the high drag forces was determined in many cases to be slight twisting of the snubber during original construction installation. As corrective action the cognizant maintenance engineer had personally briefed the mechanics involved in the reinstallation of snubbers during the current refueling outage so that improper reinstallation would not be likely. However, the licensee has not taken lasting corrective action to prevent recurrence of improper reinstallation in that no procedural caution or formal training plan had been revised to record the lesson learned from this experience and prevent future recurrences. The licensee has committed to consider lasting corrective action for this item (Followup Item 50-275/86-29-02).

Operations Control of System Operability (During Snubber Surveillance)

Intended Controls

Operations personnel are responsible for ensuring system operability. The maintenance personnel are responsible to remove, test and replace the snubbers.

The licensee has procedures to control maintenance and operability. Work clearances are approved by operations to allow work on equipment as described in NPAP C-6 Revision 5 dated 11/06/85, "Clearances." More specifically, for work at Diablo Canyon, the

Work clearance process is described by procedure NPAP C-6S1 Revision 10 dated 4/14/86 "Administrative Procedure, Clearance Request/Job Assignment." Even more specifically, for important systems, the method of control is described in NPAP C-6S4 Revision 3 dated 7/8/86 "Control of Equipment Required by the Plant Technical Specifications." This last procedure required a form (Equipment Operability Status Sheet) be filled out prior to removing equipment from service. The form (69-10860) has entries to define the equipment, record the time it was made inoperable, and the action required. This procedure also required the Shift Foreman to review all the outstanding forms at the beginning of each shift and prior to removing any other necessary equipment from service.

Thus, the procedure establishes a method by which equipment (including snubbers) taken out of service could be tracked and system operability (and/or actions required) could be controlled to meet technical specification requirements.

Loss of Operations Control, Abandonment of Procedure

When snubber testing results dictated greatly increased numbers of snubber testing, the licensee procedures for control of system operability were largely abandoned. The number of forms (Equipment Operability Status Sheets) to be reviewed each shift by the Operations shift foreman became unmanageably large. As discussed later in this report,several shift foreman stated they were not reviewing the status sheets each shift in violation of NPAP C-6S4 They further stated that they understood that maintenance personnel were controlling the snubber/system operability.

Informal Maintenance Controls

The inspectors examined the informally established maintenance controls which were being used to protect system operability. The maintenance foreman who assigned snubber work kept an informal log which noted when snubber work was started and completed. If a snubber was removed for a period of time approaching 72 hours, he would call the control room and determine whether the snubber would affect technical specification action/system operability. The inspector sampled the maintenance foreman's log for important systems and verified that the informal system was apparently working, that no system inoperability had occurred.

Although work important to safety should be controlled by procedures (which have been reviewed and approved by management), the maintenance foreman's informal log appeared, in fact, to ensure system operability.

Lack of Management Awareness

Many site personnel including management were aware of the snubber testing results and the increased snubber testing, and the burden of keeping track of system operability. The informal method of control which evolved was apparently the result of a cooperative effort on the part of operations, maintenance and work planning personnel.

The management personnel interviewed, in operations and maintenance, stated they were not aware that the formal procedures for operability control had been abandoned upon expansion of the snubber sample size.

Licensee management committed to examine the reasons for lack of management awareness and control in this case and take corrective action. The lack of management awareness and control in this case will be factored into the normal course of future inspections in this area.

Failure to Follow Procedure

The facility Technical Specifications require that there be written procedures for equipment control and that these procedures be followed.

Procedure NPAP C-6S4, Revision 3 "Control of Equipment Required by the Plant Technical Specifications" requires operations personnel control and track equipment required to be operable and specifically requires the shift foreman review all outstanding operability status sheets at the beginning of each shift.

On October 16 and 17, 1986, the inspector interviewed the operations shift foreman, the day shift, the swing shift, and the graveyard shift; they all stated that for snubber removal work they had not been reviewing the status sheets at the beginning of each shift. They further stated that, for snubber work, system operability was not being controlled and tracked by operations personnel.

This was evident by a review of the status sheets that day. For example:

- Snubbers 12-152 and 12-67 on clearance request 2109 were shown on the status sheets as removed on October 2, 1986 at 0245 a.m. These snubbers are in the boration flow path which would have been considered inoperable after 72 hours or on October 5, 1986 at 0245 a.m. At that point core alterations would have had to cease. Core alterations continued however until October 7, 1986. In fact, these snubbers were not removed for greater than 72 hours as verified by the inspector.

- Many of the status sheets indicated snubbers as required in Mode 6 and showed those snubbers as having been removed for greater than 72 hours (CR 1999, 2045, 2051, 2052, 2066, 2075, 2079, 2090, 2094, 2108, and 2109). As previously stated, the inspector sampled the informal controls by the maintenance foreman and found no systems required by Technical Specifications to be inoperable.

The failure to follow a procedure for the control of important safety equipment is considered an apparent violation of regulations (Item 50-275/86-29-03).

b. Unit 2 Containment Hydrogen Monitor

The inspector observed portions of the calibration activities performed on Containment Hydrogen Monitor Channel 83 in accordance with STP-I-46B. Specifically, the I&C technicians were in the process of verifying the pressure integrity of sampling system. The procedure calls for a maximum leak rate of 0.25 psig per 10 minutes when pressurized to 90 psig. In its as found condition, the system had a leak rate of 2 psig per 10 minutes. The I&C technicians were testing to identify the location of the system leaks. Two weeks after the search was initiated, at the time of the inspection, the system leak rate had been reduced to 0.7 psig per 10 minutes. The inspector noted that the pressure gauge used to determine system leakage was past its calibration date. However, since the gauge was being used during the trouble shooting phase of the procedure and was properly labeled "out-of-calibration" its use was acceptable. The STP was performed by qualified technicians using properly qualified replacement parts.

6. Routine Inspection

a. Unit 1 Containment Doors

The inspectors conducted an extensive examination of the August 30, 1986 event in Unit 1 wherein both containment doors were opened with the reactor in Mode 3 having just shut down for the refueling outage. The examination included an examination of the history of the mechanical performance of the door and an evaluation of the thoroughness of the licensee's corrective actions taken in response to the event and its precursors.

Background

The containment personnel airlock is a chamber into the containment with two airtight doors. Both of the doors are ordinarily shut. The doors may be opened, one at a time, for personnel entries when the reactor is in operational Modes 1-4. The airlock is considered a principle safety barrier against the release of radioactive material.

The doors are designed with a mechanical interlock such that only one door can be opened at a time. The technical specifications require periodic testing of the airlock tightness, the door seal tightness and the proper functioning of the interlock mechanism.

The examination of events and licensee corrective action before and after the August 30, 1986 event indicate that licensee corrective actions have not been effective in precluding recurrences as explained below.

Sequence of Events

Prior to August 30, 1986

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February 28, 1984: NCR DC1-84-OP N043 was written describing both doors having been opened due to a failure of the interlock mechanism and the personnel using the door not being properly trained.

May 16, 1985: NCR DC2-85 MM N045 was written for an event of 5/9/85 where both doors were opened when the mechanical interlock failed during fuel movement in Unit 2. The cause was attributed to overuse of the door and a lack of a formal maintenance program on the doors. Corrective action was defined to provide a maintenance procedure and to review the door design for adequacy. (Note the door design was subsequently determined to be adequate with the stipulation that personnel be trained in the correct operation of the door and adequate preventative maintenance be performed).

October 14, 1985: NCR DC2 85 TN N108 was written to document a September 28, 1985 event where the airlock failed it's leakage test because the linkages were forced out of adjustment by improper operation causing the equalizing valves to be an open leak path. The corrective action was to prepare a film to show the proper operation of the containment airlock (not complete) and to initiate a design change to change the equalizing valve size and to replace the shaft packing with an o-ring design (not complete).

<u>August 30 and Later</u>

August 30, 1986: At 0005, the inner airlock door flew open with the outer door already already open. The personnel opening the door were contract health physics personnel. The person opening the second door had not been (and was not required to be) formally trained. He had been familiarized with door operation through on the job familiarization. The force of the door opening bruised but did not seriously injure the door operator. The person inside the hatch had to hold on the structure to prevent being swept away. Inside containment a desk was overturned by the force of the wind and a metal lid was torn off a tool box. After a few minutes the pressure equalized, people were checked for injury and the inner door was closed. The person who opened the inner door stated he had properly observed the red light go out (indicating the outer door was closed) prior to opening the inner door. He stated he had equalized pressure prior to opening the door

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(but clearly he had not, as evidenced by the resulting event).

The operating shift foreman was appraised of the event, properly logged it, but did not make an NRC notification. A late notification was made by licensee management later in that day.

A maintenance mechanic was dispatched to repair the door and reported the door repaired.

> Note: Later during the week of October 27, 1986, as a result of NRC inquiry, it became known that the mechanic found nothing wrong with the door, had tested the interlock mechanism with satisfactory results and declared the door repaired without having found any viable reason for the event. The nonconformance report eventually written (DC1-86 MM-N101) inaccurately identified the cause as "wear" and the associated action requests (ARs) which describe the corrective action taken provide other equally erroneous causes such as "interlock mechanism bent out of shape." These erroneous entries were apparently due to inaccurate verbal dissemination of information (Reference AR 32762, AR 32761, AR 32844).

August 30, 1986: Swing Shift Maintenance personnel were dispatched to the containment airlock because personnel were unable to open the doors. Maintenance personnel entered the containment through the emergency hatches, fully closed the inner airlock door, and were then able to open the outer door. They noted and corrected warning light limit switch cams out of adjustment, replaced a missing U-joint bearing pin and a U-joint roll pin.

September 3, 1986: The Technical Review Group (TRG) met to determine root cause and corrective action for the event. The group was not aware that the graveyard mechanic had not in fact performed any repair. The group prepared and issued a nonconformance report, NCR DC1-86-MM-N101 which identified wear as the basic cause of the event. The NCR directed that a design change be prepared for both units, that the test procedure be revised to verify operation of lights and horns. Operations was instructed to verify the adequacy of door operating instructions.

September 26, 1986: The Licensee issued LER 86-011 regarding the event. The LER states the failure was due to excessive wear which was repaired. The actual cause has not yet been determined.

September 27, 1986: A broken interlock cable failed and was replaced.

October 3, 1986: Interlock mechanism failed. The cause was an idler gear had become disengaged due to a missing tack weld.

October 13, 1986: Interlock indicating lights did not work and were repaired.

October 14, 1986: The PG&E General Office Nuclear Plant Review and Audit Committee met in a regular meeting and reviewed, among other items, the LER and NCR associated with the August 30, 1986 containment door event. The committee had no comment.

October 17, 1986: A U-joint bearing pin fell out and was replaced and hose clamped. Also cam followers and roll pins were replaced and the mechanism timing was adjusted.

October 17, 1986: A design change, DC 1-SM-37192, was issued to improve operability of the containment door interlock mechanism.

October 31, 1986: The outer door latching mechanism was declared inoperable due to difficulties with full unlatching of the door. The door was examined and declared sufficiently operable.

November 5, 1986: The licensee attempted to recreate the event of August 30 to demonstrate a theory that the interlock mechanism problem was caused by one of the mechanism linkages being installed 180 degrees out of syncronization by an unauthorized reassembly of a bearing pin which might have fallen out. The demonstration was unsuccessful in that the event of August 30 could not be recreated. With the linkage 180 degrees out of rotation the doors could not be opened.

Licensee Actions

Design

The licensee design change to be implemented in Unit 1 prior to restart should improve the mechanism universal joints by providing bearing pins with capturing devices to prevent them from falling out. It also replaces easily sheared roll pins with stronger

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shoulder bolts. It revises the latch bar mechanism to prevent failures of the cable mechanism. It improves the size and strength of the interlock box stop pin to prevent inadvertent shearing. The licensee further plans additional modifications (for after Unit 1 restart) to revise the alarm logic to provide an audible alarm only if both doors are being operated simultaneously.

The licensee actions do not address the pressure equalization indication available to personnel. The airlock is equipped with a pressure gage that reads from 0-60 psig. The gage is inadequate to indicate normal pressure differential in the airlock which is ordinarily no more than 1 psig. Personnel have been "listening" for equalization (by listening to the rush of air through the vent valve) or by "feeling" for equalization (by placing a hand on the vent valve exhaust) or by "observing" equalization (after taping a piece of string to the vent valve exhaust for a visual indicator).

Surveillance Test Procedure

On September 18, 1986 the licensee issued an on-the-job change to the air lock door interlock verification procedure, STP M-8E. The added steps require that the operator verify that the buzzer and lights on the doors activate and that the control room annunciator actuates. Previously, the procedure had only required that the interlock mechanism be verified operable (by challenging it).

The test procedure as revised is inadequate in that it does not require verification that the lights and alarms activate and deactivate in the proper sequence and time in relationship to the turning of the door handles and the unlatching of the respective doors. The licensee has committed to review the procedure again for adequacy.

The inspector noted a second apparent deficiency in the test procedure. The STP also tests the Emergency air lock doors (which are a second, smaller personnel access to the containment). The procedure as written directly challenges the interlock mechanism with one door already open but does not caution the operator to ensure containment and atmospheric pressures are essentially equal. The vendor's technical manual (DC 663075-905) has a specific caution that extensive damage to the door operating mechanism could occur if the operator attempts to open both doors with a differential pressure. The licensee has committed to review this aspect of STP M-8E.

Preventative Maintenance

The preventative maintenance procedure for the containment personnel hatch is MP-M-566. The procedure as written essentially performs lubrication and inspects for general evidence of wear. The procedure does not check for critical items such as the condition of the interlock box stop pin (which is not visible without disassembly of the interlock box). The procedure does not check and adjust electrical switch functions, cam actuation timing or mechanical timing of the interlock for the door mechanism.

The procedure as written does not appear to be an acceptable preventative maintenance procedure and was not identified for correction by the TRG review of the NCR.

Maintenance Training

The licensee does not require specific training for mechanics to work on the containment door. The mechanics are generally familiarized through on-the-job job training. The failure of the original graveyard mechanic to find anything wrong with the door mechanism indicates that on-the-job training is not sufficient.

Maintenance Records

The records of maintenance performed do not appear to be adequate. The mechanic dispatched to the containment doors on August 30, 1986 on graveyard shift (after the doors had blown open) had found nothing wrong and had corrected nothing. The action requests describing what was found were written by several other people apparently based on heresay and described conditions not found and actions not in fact taken (reference AR's A 32762, 32761, 32844).

Door Operator Training and Qualification

The training and qualification of personnel authorized to operate the containment door mechanism does not appear to be adequate. The long standing problem of damage to the operating mechanism could have been resolved by making the door mechanism less susceptible to damage by design improvement or by making the physical operation of the door a much more controlled activity.

The licensee does not require formal qualification to operate the door. Personnel only receive on-the-job instruction.

The inspector observed the training of three labor-janitor craft who had been assigned to operate the door on the morning of August 30, 1986. These craft were assigned as dedicated door operations personnel in response to the event to preclude additional damage. The operation of the door was demonstrated to the personnel. They were not required to demonstrate their ability of properly operate the door.

The contract health physics people involved in the event earlier had been familiarized with door operation through similar on-the-job training which was evidently insufficient to ensure pressure equalization had occurred prior to opening the door.

The continued malfunctions of the door after the August 30, 1986 event have been attributed to abuse of the mechanism by licensee personnel through careless operation. This further indicates the training and qualification of personnel for door operation is not adequate.

Root Cause

The licensee was cautioned by the inspector on the morning of August 30, 1986 that a thorough root cause analysis and a comprehensive examination and corrective action program should be initiated for the containment door event.

The licensee's procedures and organizations chartered to determine the root cause of the August 30, 1986 event had functioned and actions were identified on September 3, 1986.

The root cause analysis was inadequate in that it was defined as mechanical failure due to wear; however, the cause of the event has still not been clearly identified.

The apparent root causes are described in the preceding paragraphs and appears to be inadequate design, inadequate surveillance testing, inadequate preventative maintenance, inadequate maintenance records and inadequate door operator training and qualification.

Ineffective Corrective Action

Operational problems with the containment air lock doors have been identified as early as February 1984. The problems resulted in the event of August 30, 1986 at the start of the refueling outage and have continued through the outage.

10 CFR 50 Appendix B Criterion XVI requires that for significant conditions adverse to quality measures be established to assure that the cause of the condition is determined and corrective action taken to preclude repetition.

The licensee's failure to assure that the cause of the containment air lock door failures was properly determined and the failure to take appropriate corrective action to preclude repetition is an apparent violation.

Enforcement action will be the subject of separate correspondence. (Item 50-275/86-29-04).

7. Open Items

a. (Closed) Unresolved Item 50-275/86-23-02 Unit 1 Containment Doors Both Open

The unresolved item is considered closed based on the extensive examination of the occurrence as described in paragraph 6. of this report and the determination that there was an apparent violation of NRC regulations.

8. Licensee Event Report Followup

Based on an in-office review, the following LERs were closed out by the resident inspectors:

Unit 1: 86-15, 86-011 (See paragraph 6. of this report)

[illegible]

[illegible]

[illegible]

Unit 2: 86-23

The LERs were reviewed for event description, root cause, corrective actions taken, generic applicability and timeliness of reporting.

No violations or deviations were identified.

9. Followup of Headquarters Requests

In response to an October 30, 1986 event at Indian Point Unit 2, the residents were requested to ascertain certain similarities or differences in the Diablo Canyon auxiliary feedwater system as compared to Indian Point.

The residents determined that Diablo Canyon does not have the same type of steam driven pump, does not have a steam relief valve on the steam admission line to the pump and that the steam driven pump does start automatically. Consequently it was determined that the Diablo Canyon site is not likely to have the same event.

11. Unit 1 Refueling

The Unit 1 refueling outage continued during this inspection period. Operating Procedure (OP) B-8D "Refueling Prerequisites" was utilized by the licensee for verification of valve lineups and to assure readiness of equipment and associated systems for refueling. Core unloading was accomplished in accordance with OP B-8D S-1 "Core Unloading Sequence," and OP B-8D S-2 "Core Loading Sequence" specified the sequence for insertion of the fuel. Each fuel assembly and insert contained Westinghouse identification numbers. Core maps and fuel assembly tracking sheets were formulated by Reactor Engineering to specify sequencing and positioning of the fuel assemblies in the core and spent fuel pool. Fuel status boards were utilized in the control room, containment and fuel handling building to document positioning of the fuel. Compliance with precautions and limitations specified for the refueling evolution was verified by the inspectors. Shift manning requirements for refueling operations were also verified to have been met. Additionally, the inspector performed a walkdown of containment penetration isolation valves located outside containment to assure containment integrity was being maintained during fuel movement or core alterations as specified in Attachment C to OP B-8D and OP K-10B2 "Sealed Valve Checklist for Containment Manual Isolation Valves (Outside Containment)."

During withdrawal of the fuel assemblies from the core, the licensee noted that an Inconel 718 grid strap on assembly A-06 was missing a 1.5 by .4 inch section with a nominal thickness of 18.5 mils. Accordingly, the licensee commissioned Westinghouse to perform an evaluation to assess the ability of Unit 1 to startup and continue safe reactor operation with this loose part in the reactor coolant system (RCS). The evaluation concluded the part could migrate through the RCS, but would not adversely affect the fuel, rod cluster control assemblies, reactor coolant pumps, steam generators, reactor internals or residual heat removal system

components. The Plant Safety Review Committee determined the presence of this loose part in the RCS does not represent an unreviewed safety question. The damaged fuel assembly was not re-inserted into the core. Assembly C-42 was also damaged during offload, when it was scraped against the core baffle. The second and third spacer grids from the bottom were torn. Westinghouse determined this assembly was satisfactory for re-use with the damaged side of the grid strap positioned against the core baffle.

Tipping of assembly A-06 (approximately 10 degrees from vertical in the reactor vessel) was previously described in the Event Followup section of this report.

On November 4, 1986 reactor vessel head tensioning began and at 0300 on November 5, 1986 Unit 1 transitioned to Mode 5 (cold shutdown) of reactor operation.

No violations or deviations were identified.

11. 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 3. j. of this report.

12. Exit

Weekly exit meetings were conducted with the licensee's representatives identified in paragraph 1 on October 10, 24, and 31, 1986. The inspectors summarized the scope and findings of the inspection as described in this report.

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INDEX OF ACRONYMS

AR	Action Requests
AFW	Auxiliary Feedwater
ESF	Engineering Safety Features
FT	Flow Transmitter
I&C	Instrumentation and Control
LER	Licensee Event Report
LCO	Limiting Conditions for Operation
MSIV	Main Steam Isolation Valve
NCR	Non-Conformance Report
NPAP	Nuclear Plant Administrative Procedure
NRC	Nuclear Regulatory Commission
PG&E	Pacific Gas and Electric
RHR	Residual Heat Removal
SFM	Shift Foreman
SG	Steam Generator
SI	Safety Injection
STP	Surveillance Test Procedure
TRG	Technical Review Group
TS	Technical Specification