U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/87-13 and 50-323/87-12

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: March 15 through April 25, 1987

Inspectors: M. M. Mendonca for — 5/15/87
L. M. Padovan, Resident Inspector — Date Signed

M. M. Mendonca for — 5/15/87
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Approved by: M. M. Mendonca — 5/15/87
M. M. Mendonca, Chief, Reactor Projects Section 1 — Date Signed

Summary:

Inspection from March 15 through April 25, 1987 (Report Nos. 50-275/87-13 and 50-323/87-12)

Areas Inspected: The inspection included routine inspections of plant operations, follow-up of on-site events, maintenance and surveillance activities, and licensee event reports (LERs), as well as selected independent inspection activities. Inspection Procedures 30703, 57050, 61726, 62703, 71707, 71710, 73051, 90712, 92700, 92701, and 93702 were applied during this inspection.

Results of Inspection: Three violations were identified. The first is for failure to take prompt corrective action for an identified deficiency. The second is for a violation of facility Technical Specification 3.3.1. This is a violation of procedure for control room activities.

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
*R. G. Todaro, Security Supervisor
*D. B. Miklush, Maintenance Manager
J. E. Molden, Operations Training Supervisor
W. G. Crockett, Instrumentation and Control Maintenance Manager
M. J. Angus, Work Planning Manager
L. F. Womack, Operations Manager
*T. L. Grebel, Regulatory Compliance Supervisor
S. R. Fridley, Senior Operations Supervisor
R. S. Weinberg, News Service Representative
*M. W. Stephens, I&C Administration General Foreman
D. A. Malone, Senior I&C Supervisor
B. L. Peterson, Instrument Maintenance General Foreman
D. L. Bauer, Senior Power Production Engineer, Electrical Maintenance

M. M. Mendonca, Chief, Reactor Projects Section 1, from US NRC Region V was also in attendance at the resident's exit meeting.

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

*Denotes those attending the exit interview.

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 LCOs as prescribed in the facility Technical Specifications. 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.

(i) Storage of pressurized gas bottles.

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.

While touring a Unit 2 containment penetration area, the inspector observed an acetylene pressurized gas (welding) bottle attached to an approximately 2 inch component cooling water supply line for support. The welding, authorized by Construction Entry Permit 15107, was for replacement of Post-LOCA Panel 80. The inspector discussed the supporting of the gas bottle with the attendant Bechtel welder. The welder indicated he had not received instruction about attaching pressurized gas bottles to safety related piping. This situation was brought to the attention of the General Construction Project Superintendent, and he was reminded that similar problems were encountered during the Unit 1 refueling, and that corrective actions should have been previously instituted. The Superintendent indicated the topic would be discussed with Bechtel supervision.

The inspector also noticed general area lighting in the Unit 2 auxiliary building had deteriorated. For example, some lighting fixtures were not functioning around centrifugal charging pumps 2-1 and 2-2, entry area to the residual heat removal (RHR) heat exchanger 2-2 and boron injection tank (BIT) room, component cooling water pump (CCW) 2-3, turbine driven auxiliary feedwater pump, fuel handling building 100 foot elevation corridor by the RWST, and the interspace room (containing FI-85 and 88 for CCW to the RHR heat exchanger) from the auxiliary building to the 100 foot containment penetration area. These items were brought to management's attention for correction.

b. Units 1 and 2 Fuel Handling Building Ventilation System Walkdown (Engineered Safety Features System Walkdowns)

The inspector performed a walkdown of physically accessible portions of the Fuel Handling Building Ventilation Systems of Units 1 and 2. No equipment conditions or items that might degrade system performance were identified.

c. Labeling of Unit 2 Control Room Annunciator Window

On Saturday, April 18, 1987, unused control room annunciator window PK 12-3 began flashing. Operations personnel apparently attached a slip of paper to the window of the irrelevant annunciator. However, in an act of levity, inappropriate and unprofessional wording was written on the paper. This wording was later transferred to the window through the use of a marking pen. Specifically, the words were "EAT AT JOE'S." Another shift subsequently replaced the wording with a different, but similarly inapproriate and unprofessional phrase utilizing a more formal lettering method. The words on this occasion were "PATRONIZE BOB'S BEANERY." At about 11:30 a.m. on April 19, a member of an Augmented Inspection Team (AIT) observed the inappropriate wording on the annunciator. On April 20, 1987 at approximately 8:00 a.m., a resident inspector and the AIT member brought the fact of the annunciator wording to the attention of the plant superintendent and other plant management. However, just prior to the NRC's notification of plant management, at 7:30 a.m. on April 20th, the window lettering was identified by the Operations Manager who immediatly directed that the lettering be removed. Removal of the lettering was observed by other plant managers, as well as representatives of the NRC.

The fact that several different shifts of plant operators and their supervisors were aware of and condoned the use of inappropriate and unprofessional wording in the control room, raises a concern regarding the proper exercise of professional control room responsibilities, and the proper job performance attitude, by operations personnel. The Operations Manager and Plant Superintendent met with the involved shift formen (SFM) to discuss their role in setting the leadership tone for the entire facility. The managers emphasized that actions of this nature "never have and never will be acceptable behavior." Separately, the Operations Manager met with all SFM and shift technical advisors (STAs) to discuss why the actions taken by the involved crews were not acceptable. No disagreements were presented by the SFM and STAs.

The managers ascertained that the actions taken by the operators were an attempt to heighten the fact that the flashing annunciator was a "nuisance alarm" in need of repair. Operators did conclude no effect on plant safety or operations would result prior to labeling the window. However, the NRC is concerned that this instance represents a failure of first line supervision, or higher, to set a proper and professional tone in the conduct of control room operations and that the enforcement actions contained in this and other reports may have resulted from such inattention to control room responsibilities.

During the next month, the Plant Manager and Plant Superintendent plan to discuss overall management expectations with all operations crews. The use of inappropriate wording on an annunciator is a potentially distracting activity in the control room, contrary to NPAP A-103, and is considered a violation (Open Item 50-323/87-12-02).

One violation and no deviations were identified.

3. Onsite Event Follow-up

a. Unit 2 Safety Injection and Reactor Trip

The Unit 2 reactor had a safety injection, reactor trip and unit trip on March 21, 1987 at 7:42 a.m.. The unit was at 97% power and ramping to 100% following a routine power reduction for turbine governor valve testing. Because of the safety injection, the licensee declared as unusual event. Proper notifications were made in a timely manner. The cause was determined to be the unplanned closure of main steam isolation valve (MSIV) 2-FCV-41. The closure of this valve caused the steam flow in the other 3 steam leads to increase. The high steam flow resulted in low steam generator pressures. The coincidence of high steam flow and low steam generator pressure caused the safety injection signal.

The safety injection/trip recovery was normal. No offsite releases occurred as a result of the event. All equipment operated normally.

The cause of the MSIV closure was subsequently determined to be a short in the MSIV position indication switch (POS 821). The electrical control circuity is such that a short across the position switch causes an air solenoid valve (SV 298) to open, bleeding air from the air operator of MSIV FCV-41, allowing the valve to begin to drift shut. Because FCV-41 is a reverse mounted power operated check valve, as soon as the disk dropped a few degrees into the flow stream, the force of the steam flow caused it to slam shut, as designed.

The cause of the short in POS 821 was later determined to be water intrusion into the switch, presumably from heavy rains that morning. The switch is designed to be weathertight but examination showed the sealing gasket material had leaked over an extensive period of time.

The licensee's investigative actions included:

- The determination of the cause of the closure of FCV-41 discussed above.

- An engineering walkdown examination of piping affected by the sudden closure of FCV-41. The results were satisfactory. The walkdown identified three suspect piping snubbers which subsequently tested satisfactorily.

- An x-ray examination of valve FCV-41, for any damage to the seat or disk. The results were satisfactory. The last two

examinations were not required by federal regulations but were good prudent technical actions taken by the licensee.

- The corresponding position switches of the other Unit 2 environmentally exposed MSIVs were checked electrically with high voltage (meggered) to verify no water intrusion and satisfactory operation.

Other corrective actions taken prior to restart, in addition to the above, included replacement of the defective switch and its mounting and cabling harness (proper engineering approvals were obtained). Functional testing of the environmentally exposed MSIVs in Unit 2 was performed. The Unit returned to power on March 26, 1987. The resident inspector attended the plant Technical Review Group (TRG) meeting held on the event. The group categorized the event as isolated, but recognized the possibility that the other Unit 2 switches in dry environments and the Unit 1 switches might be subject to similar failure. The TRG therefore decided to recommend replacement of all such switches in the next refueling outages of Units 1 and 2. They also scheduled meggering of the exposed Unit 1 switches at the next unscheduled outage.

The licensee had examined industry failure data bases for equipment and found no evidence of repeated failure for these switches. The licensee therefore determined that Part 21 reportability is not required for this switch.

The licensee performed a review of past problem reports on these switches and determined that in September 1986 a similar electrical problem was noted on FCV-41 (ground indication - valve would not stay open) but the condition cleared and would not repeat. The TRG concluded that the condition at that time was possibly caused by the switch. Unit 1 was also found to have a problem with burned out contacts on a similar switch which may have been caused by a similar condition. The Unit 1 situation was corrected by a design change allowing the use of spare contacts in the switch. These indicators might have led to the discovery of deteriorated gaskets in the switch, but disassembly of the switch was not performed because the switch is not manufactured in a way such that it can be disassembled for inspection (it is of riveted construction).

The inspector inquired as to whether the licensee would conduct a study of other equipment which is environmentally qualified (EQ), has sealing gaskets, and has a similar situation where the gaskets are not required to be replaced periodically. The inspector discussed the fact that most EQ equipment with gaskets have the gaskets replaced periodically (generally 2 years). The licensee is considering this action (Open Item 50-323/87-12-01).

b. <u>Unit 1 Reactor Trip Due to 500 KV System Disturbance</u>

On March 15, 1987 with Unit 1 in Mode 1, a reactor trip occurred when an airplane crashed into the Diablo Canyon-Gates 500 kV transmission line approximately 50 miles from the plant site. When

the airplane collided with the 500 kV transmission line, a three phase to ground electrical fault occurred, which caused a large 500 kV system current and voltage transient. The transient created a low voltage condition on the plant auxiliary power system and caused a reactor trip due to reactor coolant pump bus undervoltge relay actuation. The appropriate emergency procedures were followed, the unit was stabilized in Mode 3, and a significant event was declared. All safety systems functioned properly.

At the time of the event, the Unit 1 main generator voltage regulator was in manual control, pending regulator adjustments to eliminate undesirable system fluctuations observed earlier while in automatic control. The Unit 2 main generator voltage regulator was in automatic control at the time of the event, and was able to adequately compensate for the voltage transient permitting continued power operation of Unit 2.

The licensee determined the root cause of the reactor trip was the inability of the unit to withstand the major 500 kV voltage transient with the main generator voltage regulator in manual control. With the regulator in manual control, a low voltage condition on the reactor coolant pump bus could not be averted. Subsequently, adjustments to the voltage regulator were completed and the Unit 1 voltage regulator was returned to automatic control.

c. RHR Crosstie Valve Isolation

On March 17, 1987 at 0625 PST with Unit 2 at 100 percent power, RHR crosstie valve 8716B was closed and removed from service for installation of valve position indication. Operations personnel later recognized this action placed the plant into a configuration described in IE Information Notice (IN) 87-01 "RHR Valve Misalignment Causes Degradation of ECCS in PWRs." Closing valve 8716B was not consistent with the plant's RHR system safety analysis assumption that RHR injection into all four Reactor Coolant System (RCS) cold legs would be available, assuming a single active failure of one of the RHR pumps. With the crosstie valve closed, and if only one RHR pump was operable, injection flow would be provided to only two of the RCS cold legs. However, during the time that valve 8716B was closed, both RHR pumps were operable and together were capable of injecting into all four RCS cold legs. Upon identification of the concern, RHR crosstie valve 8716B was opened and RHR system configuration was returned to normal.

As corrective action, additional guidance was provided to Operations personnel regarding the repositioning or removal from service of Emergency Core Cooling System (ECCS) valves that are system related rather than train related. Plant Engineering has reviewed all applicable test procedures relative to this guidance. Also, Westinghouse was contacted to perform a site specific analysis regarding the acceptability of injection into only two RCS cold legs. The inspector forwarded information to Region V about a potential generic safety question concerning the need for Technical Specifications for the RHR crosstie valves.

Information possessed by the licensee, describing the impact of closing a crosstie valve on RHR system operability, was not made available to plant operators and personnel involved in equipment clearance activities in a timely manner. On October 30, 1986 the Onsite Safety Review Group (OSRG) issued Action Request A0042404, which identified the consequences of isolating an RHR crosstie valve, and specifically indicated operations personnel should be made aware of those consequences. Shortly thereafter, OSRG representatives discussed this situation with licensee management. Actions taken by PG&E included 1) submitting proposed inservice testing program changes to NRC to change the frequency of crosstie valve stroke testing from quarterly to only during cold shutdown, and 2) obtaining Westinghouse evaluation of IN 87-01. However, the licensee failed to take timely corrective action for operations personnel and clearance coordinators to prevent the situation from developing on Unit 2.

In a related matter, the Training Department had obtained information from the Institute of Nuclear Power Operations (INPO) "Network" and NRC Daily Plant Reports about the D. C. Cook plant safety injection system (SIS) crosstie valve isolation which occurred on September 12, 1986. An instructor lesson guide was prepared by the Training Department, and by February 1987 requalification training was provided to all five operating crews regarding isolating the SIS crosstie valves. However, the applicability of the SI crosstie valve information to the RHR system was not stressed enough to prevent the condition from occurring at Diablo Canyon. As corrective action, the licensee's Training Department agreed to devise ways to identify critical training information and make it stand out during training classes.

The failure to take timely corrective action, described in this section of this report, is an apparent violation of the requirements of 10 CFR 50, Appendix B (Item 50-275/87-13-01).

d. Unit 2 Loss of RHR Pump During Cold Shutdown

On April 10, 1987 while Unit 2 was in cold shutdown with the hot legs at mid-loop in preparation for the installation of the steam generator nozzle dams, both RHR pumps were shut off for 86 minutes. The RHR pumps were shut off at 2125 hours due to cavitation. The cavitation occurred due to a loss of hot leg water inventory which initiated vortexing in the RHR suction line. The loss of inventory resulted from an increase in RHR letdown to makeup volume control tank (VCT) level which was being inadvertently drained. An engineer, in preparation for a containment penetration leak rate test, was draining the reactor coolant pump seal return line. Two leaking boundary valves on this line provided the drain path from the VCT to the Reactor Coolant Drain Tank (RCDT).

The operators terminated the event when they opened a gravity feed path from the refueling water storage tank (RWST) to the RCS after receiving word that the steam generator manways, which had been scheduled for removal, were still in place. The operators were then

able to restart an RHR pump to re-establish flow through the core. The RHR pump discharge temperature registered 220 degrees F, indicating that boiling had occurred. In the process of flooding the RCS, one steam generator manway (which had been untorqued, but not removed) leaked approximately 30 gallons. In addition, steam was emitted when a tygon hose running from the reactor vessel head vent to the top of the pressurizer ruptured due to high temperatures and slight pressurization.

An NRC Augmented Inspection Team (AIT) was dispatched to the site and began investigation April 14, 1987. An analysis of this event and an evaluation of the licensee's preparedness and response will be contained in the AIT's Inspection Report (50-323/87-18).

e. Unit 1 RCP Bus E Underfrequency Relay

Between 1123 hours on April 19, and 0206 hours on April 20, 1987, one Unit 1 reactor coolant pump (RCP) underfrequency (U/F) trip channel, which had been discovered inoperable at 0930 hours on April 19, was inadvertently left in a bypassed condition. The facility Technical Specifications require that an inoperable channel be placed in a tripped condition within 6 hours.

On April 19, at approximately 0930 hours, I&C shift control technicians (SCTs) performing STP I-9A, "Trip Actuating Device Operational Test, 12 KV Undervoltage, Underfrequency," discovered that U/F relay 81VER3 would not trip when frequency was lowered below its minimum setpoint of 53.9 Hz. U/F relay 81VER3 is one of three relays which provides an input to the reactor protection system (RPS) two out of three underfrequency reactor trip. As required by Surveillance Test Procedure (STP) I-9A, an SCT attempted to notify the Shift Foreman (SFM) that 81VER3 was inoperable. However, miscommunications between the SCT and SFM resulted in the Unit 1 SFM interpreting that the SCT was having problems with the relay and was going to notify his foreman to have the problem resolved. At that time the RPS bistable related to relay 81VER3 was tripped since the relay test transfer switch was in the "Test" position and the Technical Specification Equipment Operability Status Sheet (AP C-6S4), in possession of the SFM, correctly listed the relay as tripped.

Following the discussions with operations, the mids shift Instrumentation and Control (I&C) technicians conducted a turnover with the day shift. The off going shift informed the on coming shift that the SFM had been notified of the failure of U/F relay 81VER3 and requested the oncoming shift verify the inoperability of relay 81VER3. At approximately 1030 hours the day shift SCTs went to the control room to have a turnover briefing with the SFM. However, the operability of 81VER3 was not discussed. The SCTs then proceeded to 12 KV Bus E and verified all the test equipment was setup as the mids shift had left it. They then tested relay 81VER3 and confirmed that it was inoperable.

One of the SCTs proceeded to the control room and requested permission to continue with undervoltage relay testing, the next step in STP I-9A. To continue with the undervoltage relay portion of STP I-9A, the procedure requires that the RCP underfrequency relay test switch is returned to the "NORMAL" position. Since the test switch had been turned to "NORMAL" when the SCT approached the control operator (CO), the CO, observing that the underfrequency status light was not lit, and assuming that since it was not lit and the SCT was requesting permission to proceed, the problems on relay 81VER3 had been taken care of and the relay was available for service. Based on this, the CO dated and timed the Equipment Declared Operable portion of the Technical Specification Equipment Operability sheet for 81VER3. This was done at 1123 hours. At this time, U/F relay 81VER3 was not tripped and represented a channel bypass to the logic of the RPS, i.e. a channel which would not trip on a genuine U/F condition. Therefore, a 2 out of 2 logic was required for an U/F trip on Bus E.

Once granted permission, the SCTs continued with the undervoltage relay testing. However, upon completion of the relay testing, the SCTs did not perform the "return to service" portion of the STP. This was done since relay 81VER3 was inoperable and required repair by electrical maintenance. Although it provided a tracking system for the inoperable relay, it was not timely enough to have the bistable tripped within the requirements of the technical specifications.

At approximately 0200 hours on April 20, 1987, the mids shift SCTs who had originally discovered the inoperability of relay 81VER3 entered the control room and noticed that the status light for relay 81VER3 was not lit. Upon further review they discovered that the returned to service portion of STP I-9A had not been performed and there was no indication in I&C's logs that relay 81VER3 had been repaired. When asked, the SFM informed the SCTs that as far as he knew, relay 81VER3 was operable and in service and requested the SCTs test the relay to determine its operability. At 0206 hours, the RCP U/F relay test switch was placed in "TEST", essentially tripping the channel. At 0220 hours, the SCTs determined that relay 81VER3 was still inoperable. Therefore, relay 81VER3 was in a non-tripped condition between 1123 hours and 0206 hours, a total of 15 hours and 43 minutes, following a surveillance where it had been determined inoperable.

Technical Specification 3.3.1, Table 3.3-1, Item 16, specifies that the minimum number of operable channels for the reactor trip on RCP underfrequency is two per bus, with the provisions of Action Statement 6 applicable. Action Statement 6 specifies that with the number of operable channels one less than the total number of channels, power operation may proceed provided the inoperable channel is placed in the tripped condition within 6 hours and the minimum channels operable requirement is met. Since relay 81VER3 was discovered inoperable at 0930 hours, it was required to be tripped at 1530 hours. Therefore, the licensee operated in a

condition not provided for in their Technical Specifications for 10 hours and 36 minutes.

STP I-9A requires that for a channel out of tolerance due to an apparent module failure, the I&C supervisor and SFM are to be notified immediately that the channel is inoperable. In addition, STP I-9A restates the requirements of Technical Specification 3.3.1, specifically that an inoperable channel is placed in a tripped condition within 6 hours. Had either conditions of this procedure been successfully executed, the licensee would not have violated their Technical Specifications.

The provision in STP I-9A that requires the notification of the SFM was attempted by the SCTs. However, apparent miscommunications and the resulting assumptions led operations and I&C to reach separate conclusions with regards to the operability of relay 81VER3. This example of miscommunication appears to be related to other examples of informal or secondhand communications adversely affecting quality of work or operations (Inspection Report Nos. 50-275/87-04 and 50-323/87-04, 50-275/86-29 and 50-323/86-27, and 50-275/87-10 and 50-323/87-09). In this example, the verbal communication path, as opposed to a formal signed transfer, existed when the CO and SFM were permitted to declare the equipment operable through verbal communications with the SCTs. The licensee should consider this apparent avenue where a miscommunication can result in the return to service of inoperable equipment.

The "Precautions" section of STP I-9A reiterates the requirements of Technical Specification 3.3.1, specifically that an inoperable U/F channel is to be placed in a tripped condition within 6 hours. A tripped channel is indicated by a status light in the control room. Steps 2.h.i and 2.h.2 of STP I-9A require the SCTs to initial that the RCP U/F test switch was placed in "NORMAL" and the RCP Bus E U/F status light is out. Although the body of the procedure does not provide steps to be taken for an inoperable channel,it should have been apparent to the SCTs upon completion of these steps that they were leaving relay 81VER3 in a bypassed condition and were setting up for a Technical Specification violation as described in the precautions section of STP I-9A. The licensee should address the familiarity of personnel with the precautions section and other sections of surveillance test procedures which precede the procedure section.

The inspector noted that the licensee promptly initiated an investigation into this event. This investigation included statements from both shifts of SCTs involved on April 20 and both operations shifts involved on April 22, 1987. A Technical Review Group was convened on April 23. Proposed corrective actions include (1) an incident report which will detail the miscommunication to be read by all operations shifts and discussed with all I&C shifts and (2) a revision to STP I-9A which will separate it into ten procedures, one for each relay, and provide guidance in the body of the procedure regarding actions to be taken when an inoperable channel is discovered. However, these actions do not completely

mitigate the significance of this event in that this is an example of a reoccurring problem of communications compounded by I&C maintenance personnel not fully understanding the precautions listed in their procedure. Therefore, this is an apparent violation (Open Item 50-275/87-13-02).

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.

a. Diesel Generator Cooling Water Shutdown Switch

The inspector observed portions of calibration of temperature switch 95 which activates the jacket water temperature relay on Unit 2 diesel-generator 2-2. With the diesel in local control, and the mode control switch (on the diesel generator local panel) in the test mode, the diesel engine, generator field, and generator air circuit breaker are tripped through shutdown relay SDR-22 if the high jacket water temperature relay picks up. Work was performed in accordance with Work Order R-0018690. The as found switch setpoint was 195 degrees F, which did not fall within the acceptance band of 205 degrees F plus or minus 4 degrees F. Accordingly, the switch setpoint was adjusted to 204.8 degrees F. However, completion of the work was not possible, as electrical power to the diesel generator local control panel was not available. Without electrical power at the panel, temperature switch activation of the shutdown relay could not be observed.

b. Unit 2 Emergency Diesel Air Compressor

The inspector observed portions of preventative maintenance performed on the Unit 2 emergency diesel generator (D/G) 2-2 air compressor 2-2. The maintenance included changing the air compressor belts and filters. The inspector observed that the belts were replaced with an appropriate replacement and installed within acceptable tightness tolerances. The inspector noted that one step, with one sign-off, in the work order included the installation of three different sets of parts. The maintenance personnel involved at the time of the inspection had been issued only two sets of parts. The package had been worked on by previous crews and following crews were to complete the job. The inspector noted that with one sign-off for three parts there was the potential for confusion.

The inspector discussed this issue with the maintenance manager who found the level of control of parts for the air compressors adequate for the quality of work performed based on the following:

- The Plant Information Management System (PIMS) computer tracking of parts issued to the field is referenced by work order number and is therefore a verification of what parts are installed, and

- The air compressors are not class 1E equipment and the filters are not quality related.

The inspector also discussed this concern with work planning personnel who noted that the appropriate method for maintenance personnel to document the implementation of two parts out of three would be to add a note in the comments section of the package. The inspector reviewed the completed work package and noted that this was done. Based on the above, the inspector found the level of control of parts for this maintenance activity was adequate.

c. Unit 2 Emergency Diesel Generator 2-2 Undervoltage Auxiliary Relays

The inspector observed portions of Maintenance Procedure E-55, "Routine Preventive Maintenance of ±SG' Auxiliary Relays," performed on the 4KV breaker undervoltage auxiliary relays 27XHHB2, 27YHHB2, and 27ZHHB2 associated with emergency diesel generator 2-2. The maintenance procedure requires that the relay is cleaned thoroughly and then checked for appropriate pickup and dropout voltages. The inspector observed that the maintenance was performed with an appropriate clearance and that calibrated instruments were used to record pickup and dropout voltages.

No violations or deviations were identified.

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.

a. Diesel Engine Generator 1-3 Manual Start

The inspector observed portions of STP M-9A-3, "Diesel Engine Generator 1-3 Routine Surveillance Test." The test was performed in preparation of returning D/G 1-3 to service following a maintenance outage. As required by procedure, the diesel was started manually from the Unit 2 control room. Prior to the inspector's observation of the test, the operators attempted to parallel the diesel generator to its bus, but the breaker failed to close. It was determined that the contactor coupling had not fully made up due to the breaker not having been racked in completely. Since these are the types of problems the surveillance is designed to uncover prior to placing the diesel generators back in service, the corrective action taken was to correctly rack in the breaker. Once the breaker was closed and the diesel was slowly loaded to 2.6 MW the inspector observed an auxiliary operator collect field data. The inspector

verified testing was accomplished in accordance with an approved test procedure and that test data was accurate and complete.

b. Waste Gas System Oxygen Analyzer

The inspector observed portions of functional testing of the Unit 2 waste gas oxygen monitoring system in accordance with STP I-79A "Functional Test of Waste Gas System Oxygen Analyzer 75." Special Radiation Work Permit 86-020 was approved and in effect for the test. Alarm and protective function setpoints were found to be within acceptance criteria, and the data sheet was completed as required by the procedure. Required administrative approvals to perform the test had been obtained.

c. Unit 1 SSPS Slave Relay Operation

The inspector observed portions of STP M-16J, "Operation of Slave Relay K612 Train A & B." Slave Relay K612B, when actuated, closes steam generator blowdown and sample lines for containment isolation Phase A. Relay K612A has no function and is not tested. Technical Specification 4.3.2.1 Table 4.3-2 requires that Solid State Protection System (SSPS) slave relays related to containment isolation are tested on a nominal quarterly frequency. The licensee, however, performs slave relay testing for containment isolation within 72 hours of the Actuation Logic Testing (STP I-16A2) which is required in Table 4.3-2 to be performed on a monthly frequency or at least every 62 days on a staggered test basis. The inspector observed communications between operations personnel performing the test. Appropriate test data was taken, and systems were returned to service as required by the procedure.

No violations or deviations were identified.

6. NRC IE Information Notice 86-96 (Closed)

IE Information Notice (IE-IN) 86-96, "Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems," discusses the potential for fouling in heat exchangers in raw water systems and its affects on a facility's ability to reject heat to the ultimate heat sink. As required in Administrative Procedure (AP) C-14S1, "Dissemination of Operating Experience," the licensee reviewed IE-IN 86-96 for applicability to the Diablo Canyon Site. Their review concluded that only one safety related heat exchanger was subject to the potential for fouling, specifically the CCW heat exchanger. The Auxiliary Saltwater (ASW) system, which takes its supply from the Pacific Ocean and is the plant's ultimate heat sink, removes heat from the CCW system through the CCW Heat exchanger. The following design features and operational and maintenance activities are in place to minimize fouling of the ASW system.

1) Bar racks and traveling screens remove debris at the intake to the ASW pumps.

2) Periodic demusseling and desliming minimizes fouling of the ASW system.

3) CCW heat exchanger differential pressure (delta P) can be monitored in the control room. Excessive fouling will result in a high alarm at a delta P of 167 inches of water. The heat exchanger is considered operable with up to 170 inches of water delta P. If high delta P is verified, Annunciator Response procedures require that the heat exchanger is isolated for cleaning.

4) As part of the monthly surveillance testing program, CCW heat exchanger performance is measured.

The CCW system, which is a closed loop system that cools all other safety related water cooled heat exchangers, gets its makeup from the makeup water system. The makeup water system has three main sources of water; the seawater evaporator, Diablo Creek and associated waterwells, and the seawater reverse-osmosis unit. All sources are processed through a clarifier, filter beds and demineralizers.

Based on the above discussion, the inspector concludes the licensee has adequately addressed this issue and it is thereby closed.

No violations or deviations were identified.

7. Licensee Event Report Follow-up

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

Unit 1: 86-21, 87-02, 87-04

Unit 2: 87-01, 87-02

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

Unit 2 LER 87-01 "Reactor Trip on Low-Low Steam Generator Water Level" failed to identify miscommunication between the SFM and CO as a contributing factor to the trip. As documented in Section 3.b of NRC Inspection Report (IR) 50-323/87-09, at the time of the event the SFM was involved in a shift turnover briefing. The SFM had previously communicated to the CO that he wanted the plant to be on line by a certain time, but did not mean to suggest that the turbine ramp up should begin. However, the CO interpreted the communication such that the turbine ramp up was initiated, while other experienced operators were also participating in the briefing. Via cover letter to the IR dated March 31, 1987, the licensee was requested to provide written response to the NRC describing corrective actions to prevent reoccurrence of miscommunications of this nature. In the LER the licensee did not identify miscommunication between the SFM and CO as a contributing factor to the trip. Accordingly, Pacific Gas and Electric should take the steps necessary to be assured that this event, and all future events, are adequately assessed and reported to the NRC, and corrective actions are taken for all contributing factors to the events. The licensee agreed to revise the LER.

No violations or deviations were identified.

8. Defeated Safety Features and Intentional Entry Into T.S. 3.0.3

Recently, at another nuclear power plant in the United States, operators defeated a plant safety feature by inserting a dummy signal into safety circuitry and then intentionally entering T.S. 3.0.3 for operational convenience. In response to this occurrence, the inspectors evaluated the licensee's controls which prohibit actions of this nature at Diablo Canyon. Administrative Procedure (AP) C-4S1 "Mechanical Bypass, Jumper and Lifted Circuit Log Accountability System" specifically directs that if installation of a "jumper" results in " a change in the function of a system operation as described in the FSAR" a safety evaluation must be performed in accordance with plant procedures. For the purposes of the procedure, the term "jumper" refers to an electrical jumper, lifted electrical lead, mechanical bypass or modification, and any other bypass which renders a safety feature incapable of performing its intended function (such as insertion of a dummy signal). The safety evaluation must then be approved by the Plant Staff Review Committee prior to installation of the jumper. The inspector concludes the licensee's procedure AP C-4S1 addresses the identified concern.

Regarding intentional entry into T.S. 3.0.3. for operational convenience, Operations Department personnel indicated to the inspector that plant policy prohibits intentional entry into T.S. 3.0.3. The inspector ascertained that the licensee had no written policy in this regard, and that this policy was not specifically addressed in operator training classes. Accordingly, the licensee agreed to perform the following:

- A shift foreman's memo stating plant policy on this matter would be issued and reviewed by all operating shift crews.
- Revisions to APs to preclude intentionally entering T.S. 3.0.3 would be pursued.
- Training Lesson Plan LM-8 will be revised to inform all licensee candidates that T.S. 3.0.3 should not be intentionally entered. This policy will also be covered during requalification training of licensed operators.

No violations or deviations were identified.

9. Exit

On April 29, 1987 an exit meeting was conducted with the licensee's representatives identified in paragraph 1. The inspectors summarized the scope and findings of the inspection as described in this report.