U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/88-11 and 50-323/88-10

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:

Inspectors: M. M. Mendonca for — 6/16/88
L. M. Padovan, Resident Inspector — Date Signed

M. M. Mendonca for — 6/16/88
K. E. Johnston, Resident Inspector — Date Signed

M. M. Mendonca for — 6/16/88
P. P. Narbut, Senior Resident Inspector — Date Signed

M. M. Mendonca for — 6/16/88
J. C. Pulsipher, NRR — Date Signed

Approved by: M. M. Mendonca — 6/16/88
M. M. Mendonca, Chief, Reactor Projects Section 1 — Date Signed

Summary:

Inspection from April 10 through May 28, 1988 (Report Nos. 50-275/88-11 and 50-323/88-10)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of onsite events, open items, and licensee event reports (LERs), as well as selected independent inspection activities. Inspection Procedures 25026, 30702, 30703, 37700, 57050, 57080, 60710, 61726, 62703, 70307, 70313, 71707, 71709, 71710, 71881, 73756, 90712,,92700, 92701, 92702, 93702, and 94703 were applied during this inspection.

Results of Inspection:

Two violations were identified. The first dealt with ineffective corrective action in dealing with the loss of system cleanliness controls as described in paragraph 13. d. The second violation dealt with mechanics failing to follow procedures during maintenance activities as described in paragraph 5.a.

An unresolved item is described in paragraph 13.c. dealing with the operability of the Auxiliary Saltwater (ASW) system during the period of time that the heat exchanger differential pressure setpoint was raised.

An apparent weakness is implied by the situation of uncertain operability of the ASW system in that it can be concluded that system design bases have not been successfully communicated to plant personnel and that the result of this may have led to, or could lead to, plant personnel making system setpoint changes which they do not recognize as affecting system operability.

An additional inspector concern raised during this reporting period is the perceived lack of timely, effective corrective actions in dealing with situations in which plant personnel made errors. The two examples discussed in the report are the subject of violations; specifically repeated cleanliness problems and the failure of mechanics to follow procedures. In both cases the job at hand was corrected but plant management appeared content to allow the normal processes resolve the root cause of the problems. The normal process involves a nonconformance report and a technical review group meeting, a process that can and does take months. The action that appears to be missing is an immediate response to ensure other personnel involved in similar work are quickly alerted to the errors made.

During the reporting period there were good examples of individual plant personnel who exercised an inquisitive safety minded approach to their work. Specific examples were the identification of misaligned detectors in the main steam line radiation detectors by an I&C technician, the identification of improper surveillance schedules for time response testing of vital instrumentation channels by an I&C technician, and identification of the possibly generic problem with containment ventilation butterfly valves identified by engineers involved in the integrated leak rate test.

Additionally, the licensee's actions leading to the discovery of possible generic problems with Westinghouse ARD relays was noted as an example of thorough root cause analysis.

DETAILS

1. Persons Contacted

*J. D. Townsend, Plant Manager
*D. B. Miklush, Acting Assistant Plant Manager, Plant Superintendent
J. M. Gisclon, Acting Assistant Plant Manager for Support Services
*C. L. Eldridge, Quality Control Manager
K. C. Doss, Onsite Safety Review Group
R. G. Todaro, Security Supervisor
*T. Bennett, Acting 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
W. T. Rapp, Chairman, Onsite Safety Review Group
M. Tressler, Project Engineer, NECS

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 on May 27, 1988.

2. Operational Status of Diablo Canyon Units 1 and 2

During the reporting period Unit 1 continued its second refueling outage. Notable occurrences included the discovery of fatigue cracking in reactor coolant pump lubrication system components, some evidence of pressurizer surge line movement, possible generic problems with Westinghouse ARD relays, biological growth in diesel fuel oil day tanks, combustible fire barrier material, and indications from the ILRT that 48" butterfly valves used for containment purge and exhaust may have directionally dependent leak characteristics.

Unit 2 remaining at power for the reporting period.

3. Operational Safety Verification (71707)

a. General

During the inspection period, the inspectors observed and examined activities to verify the operational safety of the licensee's facility. The observations and examinations of those activities were conducted on a daily, weekly or monthly basis.

On a daily basis, the inspectors observed control room activities to verify compliance with selected Limiting Conditions for Operations (LCOs) as prescribed in the facility Technical Specifications (TS).

Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions, and 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.

b. <u>Application of the Quality Assurance Program to Diesel Generator Fuel Oil (Temporary Instruction 2515/93) (Closed)</u>

In January 1980, the Office of Nuclear Reactor Regulatory requested all licensees to check their Quality Assurance (QA) programs with respect to diesel generator (DG) fuel oil, and to include DG fuel oil in their QA programs or provide justification for not doing so.

The inspector verified that the licensee has included the DG fuel oil system in its QA program. The quality classification list specified the DG fuel oil storage tanks, transfer strainers, transfer filters, and transfer pumps as "Q". This implies that the provisions of Appendix B to 10 CFR 50 apply.

Section 4 of this report addresses fuel oil problems encountered during this reporting period.

No violations or deviations were identified.

4. Onsite Event Follow-up (93702)

a. On April 13, 1988, with Unit 1 in a refueling outage and Unit 2 at 100% power, results of a routine 18 month calibration of main steam line post accident monitoring radiation monitors required all eight (four per unit) steam line monitors to be declared inoperable. The GM tube detectors were found to be positioned in their main steam line shield casks such that the detectors did not fully extend into the shield aperture and were only partially sensitive to potential radiation from the steam lines. Incorrect detector positioning occurred during original installation due to poor installation instructions and calibration procedural errors. Accordingly, the monitors were considered to have been inoperable since August 1983 for Unit 1 and April 1985 for Unit 2. However, alternate proceduralized methodologies were available to identify and assess steam generator tube ruptures. Previous identification of this problem did not occur since radiation monitor surveillance test procedure (STP) I-18R2 specified presentation of the radiation source at the detector well top, rather than of the detector cask aperture due to the close proximity of the casks to the main steam lines. The licensee indicated the radiation monitor vendor would be contacted to evaluate the appropriateness of reportability under Part 21. Further followup of this event will be done during the review of licensee event report 50-275/88-11.

b. On April 16, 1988, Unit 1 experienced a spurious containment ventilation isolation due to a high radiation alarm on radiation monitors RM 11, 28, and 21. No cause was determined. The licensee made a 4 hour non-emergency 10 CFR 50.72 report. Note: Licensee actions to reduce spurious actuations caused by radiation monitors are addressed in report 50-275/88-13.

c. On April 19, 1988, Unit 1 experienced a spurious containment ventilation isolation signal due to a high alarm on RM-12 (containment particulate). No cause was determined.

d. On April 20, 1988, Unit 1 fuel reload was completed.

e. On April 22, 1988, for Unit 1, the licensee determined that technical specification 3.11.1 had been violated for some period of time not exceeding one hour and 10 minutes. The technical specification required continuous sampling of particulate and iodine samples of the plant vent. This function is usually provided by radiation monitor RE-24.

Due to planned work on RE-24, a temporary auxiliary sample pump had been properly placed in service prior to securing RE-24. During the I&C work on RE-24, technicians secured the temporary sample pump, thereby violating the technical specification.

There does not appear to be any technical consequences to this act. The unit was in a refueling outage and local portable air monitoring

equipment was in place and monitoring work activities. Additionally, a vent stack release, if one occurred, would contain primarily noble gases and a smaller amount of particulate and iodine, if any. Potential noble gas release was monitored during the entire time by RE-14A and B and showed no release.

Licensee corrective actions will be followed up through LER 88-12.

f. On April 23, 1988, Unit 1 experienced a containment ventilation isolation due to radiation monitor RM-14A spiking. No cause was determined.

g. On April 26, 1988, Regional management conducted an onsite meeting with licensee management. The results are reported in Inspection Report 50-275/88-14.

h. On May 5, 1988, during Unit 1 midloop operation for removal of steam generator nozzle dams, the licensee discovered that part of the reactor vessel vent arrangement of the temporary system, Reactor Vessel Refueling Level Indication Systems (RVRLIS), had been removed. Specifically, RVRLIS valve 613 had been removed. The licensee formed an Event Investigation Team (EIT). This event had no technical consequence in that the temporary system remained vented to atmosphere as it was intended through a different path. The error was preliminarily determined to be personnel error in that general construction personnel (GC) performed the work without a clearance. 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.

i. On May 5, 1988, during the performance of a 24 hour load test on Unit 1 diesel generator 1-1, the licensee determined that fuel oil filters were being severely clogged by biological growth. The condition identified itself as a load reduction due to fuel starvation. Operators switched to the other fuel filter and load was reestablished.

The inspector reviewed the licensee justification for continued operation of Unit 2 (Unit 1 was shutdown for refueling) and the inspector determined that the licensee's analysis of this condition was acceptable.

The inspector also reviewed the licensee's plan of action to correct the situation as well as to prevent recurrence. Initial licensee plans included tank cleaning, biocide treatment and increased testing.

Follow-up of this item will be accomplished through the licensee's event report.

j. On May 9, 1988, during planned preventative maintenance of Unit 1 reactor coolant pump bearings and their lubrication system, the

licensee noted several failed bolts, an extruded gasket and cracked parts in the assembly which provide motive force and directs lubricant flow for the reactor coolant pump thrust and radial bearings.

The problem was first identified in RCP 1-2. Investigation of the remaining pumps indicates at least one of the cracking problems may be generic since the same failure to a lesser degree was evident. The broken bolts and a second cracking problem may be isolated due to improper assembly or may be a generic vibration problem.

The licensee is continuing investigative actions and has, subsequent to the inspection period, documented this problem in voluntary LER 50-275/88-15. The licensee is planning corrective actions for Unit 1. The licensee has provided justification for continued operation of Unit 2 in the LER and the inspectors review of the JCO will be the subject of regional correspondence in conjunction with NRR review.

The residents followed licensee actions closely. Regional and NRR project management personnel were in communication with the licensee on this matter. Follow-up of this item will be conducted as part of normal inspection activities.

k. On May 10, 1988, the licensee identified the fact that time response testing for reactor trip and essential safety feature instrumentation had not been conducted in accordance with the schedule of frequencies described in the technical specifications.

The technical specification require such instrumentation to be tested on a rotational basis; specifically to be tested every "N x 18" months where "N" is the number of channels of instrumentation.

The licensee had not been doing this in all cases and had in effect confused the number of available channels with the number of components (e.g. steam generators) and therefore in some cases was testing at lesser frequency than required.

The licensee determined that Unit 1, which was shutdown, was late on time response testing for situations were there were two or less channels available.

For Unit 2, the operating plant, the licensee concluded that surveillances were not late for any time response testing but this position was predicated on an assumption that the technical specification tables (e.g. 3.3.1) did not include any requirement to test what appear to be single channel (i.e. N-1) functions every 18 months.

Discussions of this subject with regional and headquarter technical staff indicated that further review would be required upon licensee submittal of an LER dealing with the subject. The issue will be followed up through the LER process.

l. On May 11, 1988, during Unit 1 Diesel Generator 1-2's 24 hour run, the foamed fire barrier material around its' exhaust stack began to burn. The fire was quickly extinguished and no diesel generator inoperability occurred.

The fire barrier material apparently broke down when exposed to the heat of the exhaust pipe with time and became a flammable material itself. The possible generic considerations of this event were related to the regional fire specialist who will perform follow-up of this item.

The licensee removed the fire barrier material from the other diesel generator locations and is pursuing a design change for permanent corrective action. Fire watches have been set in the interim.

m. On May 12, 1988, the licensee made a 4 hour non-emergency report due to the Fuel Handling Building ventilation system switching to iodine removal mode due to a radiation monitor (RM-58) spike. No cause was determined for the spike.

n. On May 13, 1988, the inspector became aware of a nonconformance report written on April 30 which dealt with a cracked stator inboard clamping ring on the motor of a Containment Fan Cooler Unit (CFCU) motor. The inspector determined that the problem was not similar to that described by NRC Information Notice 87-30 which described generic cracks in large vertical electric motors in surge ring brackets.

The responsible licensee engineer stated that the CFCU crack had been found as part of a visual inspection during a planned maintenance activity and was not found to be generic as determined by the inspection of the other CFCU motors (inspected to that time).

o. On May 18, 1988, Unit 1 commenced pressurization for a integrated leak rate test (ILRT) of the containment. The conduct of the test and its results are discussed in section 14 of this report.

During the test it was noted the inside containment valves for containment purge supply and exhaust (RCV 11 and FCV 660) did not appear to hold pressure. Subsequent to the ILRT the licensee performed a local leak rate test of the valves and found them to be tight. The anomalous leak behavior of the valves, i.e., directionally dependent leak characteristics, caused the licensee to declare the valves inoperable in Units 1 and 2 and to commence an investigation.

At the end of this reporting period, although the seal ring of one valve had been replaced, the licensee had not been able to pressurize the valve inside containment to the required level. The licensee's Event Investigation Team was continuing its efforts to repair the valves. This matter will be followed closely as part of the routine inspection program.

p. On May 19, 1988, Unit 2 experienced a non reportable event when an I&C technician attempted to remove the display screen for the plant computer. In removing the screen a short was caused which resulted in the loss of one bus of instrument power (PY-24). This caused a number of bistables to trip, a number of feedwater controls to go to manual, rods to step in, and letdown to isolate. Subsequent operator action restored 120 VAC power. Plant parameter changes during the event were minimal due to operator actions.

q. On May 20, 1988, Unit 1 experienced a pure water spill estimated to be 500-1000 gallons of water in the 115 foot elevation of the Auxiliary Building. The spill was caused by a failure of the freeze seal isolating work on a CVCS valve. The licensee is investigating the cause of the freeze seal failure.

r. On April 28, 1988, the inspector became aware of a revision to a nonconformance report made on April 13, 1988. The nonconformance NCR DCI-87 EM-N121 was originally written on December 2, 1987, and dealt with malfunctions of diesel generator 1-1 during test. Specifically the diesel picked upload but immediately shed load. The problem was narrowed to a binding relay (a Westinghouse ARD relay). The relays binding resulted in varying contact resistance (40-1300 ohms) which affected logic circuits. Physical inspection noted concrete-like dust in the relays which was attributed (initially) to original construction dust.

Subsequently the licensee removed some of the faulty relays and sent them to the manufacturer, Westinghouse, for analysis. Westinghouse determined and stated in a reply dated March 8, 1988, that the dust like material was due to degraded solenoid potting material and that the relays had not been supplied as safety grade material.

A meeting was held by the inspector with licensee personnel on April 28, 1988. The results of the meeting indicated that 155 such relays were installed in the plant with 136 of them in the diesel generators and the remainder in non-safety related uses.

Of the 136 relays, one in each diesel generator affects low voltage logic circuits in which the contact resistance problem can affect their operability. The five relays, that are affected by contact resistance, are in circuits used only when the diesel is being tested for operability, that is, in parallel with offsite power. In an emergency situation i.e. loss of offsite power (when the diesel generators are required to load) the 5 relays would not hamper actual operability. The remaining 131 relays are in 125 Vdc circuits in make or break situations that are not affected by the contact resistance change. Of these, eight are critical relays with important functions such as engine start and water jacket pressure relays.

As corrective action, the licensee has replaced all relays in the diesel generator with signs of degradation. The remaining critical relays will be replaced during the current Unit 1 refueling outage and the upcoming Unit 2 refueling outage.

On May 3, 1988, the licensee's corrective actions, proposed actions and justification for continued operation were discussed with regional and NRR managers, and were found acceptable.

On May 26, 1988, the licensee submitted a voluntary LER regarding the degradation of the relays. This item will be followed up with licensee's LER 50-275/88-09.

s. Fire in a Unit 2 Auxiliary Building Rad Waste Dryer Cabinet

On May 24, 1988 at approximately 2:00 p.m. a fire was discovered inside a rad waste dryer cabinet. The dryer, located inside a ventilated rad waste tent area inside the Unit 2 Auxiliary Building, was being used to dry rad waste filters which had apparently collected flammable paint chips.

The fire was initially identified by a roving fire watch who notified the Operations and Radiation Protection departments. A health physics technician, wearing a respirator, extinguished the fire by unplugging the heater element, dousing the cabinet with carbon dioxide, and placing the filters and rags contained in the cabinet into a bucket of water.

The fire was out within ten minutes and an Unusual Event was not declared. The licensee suspended all rad waste dryer operations.

No violations or deviations were identified.

5. Maintenance (62703)

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. Safety Injection Spectacle Flange

On April 26, 1988, the inspector observed maintenance activities to reverse the spectacle flange on the safety injection relief valves return line to the pressurizer relief tank (PRT). The spectacle flange, consisting of a blind flange and an orifice, had been installed with the blind flange earlier in the outage to facilitate the local leak rate testing of containment penetration 71. The orifice side needed to be reinserted to return the line to service for operations and safety injection system testing.

The inspector found a number of problems with the maintenance activity:

- The work package in the field included only the odd numbered pages of Maintenance Procedure (MP) M-54.4, the procedure

governing the replacement of spiral wound gaskets used in this flange. The mechanics were not aware of the fact that half the procedure was missing prior to identification by the inspector.

- The mechanics were not using the lubricant specified in MP M-54.4 for the lubrication of bolts. They were using Chesterton instead of Felpro N-5000.

- The mechanics were not using the data sheets included in MP M-54.4 for recording flange alignment and other important data.

- The work order was poorly written, in that it did not specify the use of the data sheets for MP M-54.4 and in fact the only instructions given for final flange reassembly were: "At the completion of STP, Mech. Maint. to restore all systems to operating state, as required by engineer and foreman in charge."

The problems fall into two categories; an inadequate work package, and mechanics not following the applicable procedure. The work order was written to cover both the insertion of the blind flange and the reinsertion of the orifice. When the package was reissued to the field for the reinsertion of the orifice it included only the above step for the mechanics to perform which had not been signed off previously. The STP referred to was STP V-671, the local leak rate testing of the containment penetration. The step does not call out MP M-54.4 or its data sheets. Other steps in the work order, previously signed off, describe bolt torque and referred to MP M-54.4. However, those steps did not specify that the data sheets need to be filled out.

Although the inadequate work package contributed to the problems, the activity could have been performed correctly had the mechanics taken the time to read the package and have it corrected or requested guidance from their supervisor. This was not done and as a result the wrong lubricant was used on the bolts. The lubricant used had not been qualified to be used on safety related bolting applications. Failure to follow MP M-54.4 is an apparent violation (Enforcement Item 50-275/88-11-01).

Following identification by the inspector, the licensee identified a number of immediate corrective actions:

- The bolts were cleaned and relubricated with Felpro N-5000.

- The Maintenance Manager held a meeting with the maintenance department to discuss procedural compliance, the need to use data sheets included in procedures, and that only the materials specified by the procedure may be used.

- The Quality Control Manager gave instructions to the QC department not to approve work orders with instructions as general as "Restore all systems worked to operating state, as required by engineer or foreman in charge."

The licensee convened a Technical Review Group (TRG) to review the Nonconformance Report (NCR) associated with this incident. At the conclusion of this inspection period the TRG had not yet specified any further corrective actions.

b. Other Maintenance Activities Observed

The inspectors observed and found acceptable portions of the following maintenance activities:

- o Auxiliary Salt Water Pump 1-1 reinstallation following overhaul.
- o Unit 1 Auxiliary Building Ventilation System damper 2A gasket replacement.
- o Control rod drive mechanism repair activities.
- o Upper internals clearing operations for reassembly.
- o Repairs associated with reactor coolant pump lubrication system cracking.

One violation and no deviations were identified.

6. Surveillance (61726)

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 examined during this period included:

- o Integrated leak rate testing for Unit 1 containment described in section 14.
- o Surveillance testing of the ASW/CCW problems identified in section 13.c. of this report.
- o Inservice inspection testing, section 12. of this report.
- o Surveillance testing of the main steam line radiation monitors described in section 4.a. of this report.
- o Diesel fuel oil sampling surveillance discussed in section 4.i of this report.

No violations or deviations were identified.

7. Engineering Safety Feature Verification (71710)

The inspector walked down accessible portions of the Units 1 and 2 Auxiliary Saltwater system including local and control room indication

and system breakers. Findings are discussed in section 13.c. of this report.

No violations or deviations were identified.

8. Radiological Protection (71709)

The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors verified that health physics supervisors and professionals conducted frequent plant tours to observe activities in progress and were generally aware of significant plant activities, particularly those related to radiological conditions and/or challenges. ALARA consideration was found to be an integral part of each RWP (Radiation Work Permit).

No violations or deviations were identified.

9. Physical Security (71881)

Security activities were observed for conformance with regulatory requirements, implementation of the site security plan, and administrative procedures including vehicle and personnel access screening, personnel badging, site security force manning, compensatory measures, and protected and vital area integrity. Exterior lighting was checked during backshift inspections.

No violations or deviations were identified.

10. Licensee Event Report Follow-up (92700)

a. Status of LERs

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

Unit 1: 87-10, 87-16, 87-19, 87-23, 88-02, 88-03, 88-06, 88-12

Unit 2: 87-04, 87-14, 87-23

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

No violations or deviations were identified.

11. Open Item Follow-up (92701)

a. QC Inspector Failing To Perform Inspection (Enforcement Item 50-275/88-03-03; Closed)

The inspector reviewed the licensee's response to a Notice of Violation issued on March 28, 1988 concerning a Quality Control

Inspector who stamped and initialed his acceptance of cleanliness on his inspection plan without visually inspecting inside the body of Valve No. 8484B for cleanliness.

The inspector reviewed the corrective actions taken and found them acceptable. Therefore, this item is closed.

b. Unauthorized Entry to the Radiological Controls Area (Enforcement Item 50-323/88-04-01; Closed)

The inspector reviewed the licensee's response to a Notice of Violation issued on March 28, 1988 concerning the unauthorized entry of an individual to the Radiological Controls Area (RCA). In their response, the licensee stated that the individual was counseled by his supervisor. In addition, a review determined that the existing RCA postings, procedures and training program were adequate. However, the postings for the RCA were clarified to more clearly denote entry and exit points, and the barrier support was improved to reduce the amount of sag in the yellow-magenta rope delineating the RCA. Based on these actions, no further actions were deemed necessary.

The inspector reviewed the actions taken including the changes to the RCA barrier and found them acceptable. Therefore, this item is closed.

c. Revisions to Procedures Controlling Maintenance Performed on Energized Equipment (Follow-up Item 50-275/87-04-03; Closed)

In response to findings in Inspection Report 50-275/87-04 with respect to inadvertent control rod withdrawal due to a miscommunication between I&C and Operations, the licensee committed to revise procedures for control of equipment required to be energized during maintenance. The inspector reviewed Tagging Requirement Procedure AP C-7S1 which had been revised to require that information tags placed on equipment be documented for installation and removal. The inspector also reviewed work orders for systems required to be energized during maintenance and found that they required the technician to sign off that the Shift Foreman had been notified prior to performing the work and following completion. In addition, the work orders specified where information tags were to be hung and required their removal following maintenance. Based on the above, Open Item 50-275/87-04-03 is closed.

d. Protected Area Escort Responsibility (Enforcement Item 50-275/87-44-01, Closed)

NRC Inspection Reports 50-275/87-44 and 50-323/87-45 contained a violation regarding plant security. In a March 10, 1988, letter (DCL-88-058) PG&E addressed the identified security concerns. The inspector reviewed the licensee's corrective actions and determined them to be acceptable. Accordingly, this item is considered closed. Details pertaining to the corrective actions are not provided in

this report due to the security safeguards nature of the information.

e. Inoperable Unit 1 Rod Position Deviation Monitor (Open Item 50-275/87-38-02, Closed)

Open item 87-38-02 was concerned with root cause determination of the "P-250 Rx Alm Axial Flux/Rod Pos" alarm window unexpectedly clearing during a plant evolution. As explained in LER 87-19-01, the cause of the problem was identified to be in a subroutine of the computer program which controlled alarm functions. The subroutine was found to function unpredictably if the rod bank demand values were initialized improperly. Corrective actions were described in the LER. This item is considered closed.

f. Entry into Technical Specification (TS) 3.0.3 (Open Item 50-275/87-38-03, Closed)

This open item was concerned with the root cause determination of fuse failures in control rod drives. As described in LER 50-275/87-16-01, fuse failure was attributed to poor solder connections at the fuse end caps. Corrective actions were described in the LER. This item is considered closed.

g. Digital Electro-hydraulic Control (DEHC) System Malfunction (Open Item 50-275/87-04-01, Closed)

This open item involved inadvertent disruption of the DEHC load control (software) program during turbine maintenance activities. As corrective action, the licensee revised Operating Procedure C-3:II "Main Unit Turbine-Startup" to add a caution that after an outage or any major turbine maintenance, the P-2000 computer (DEHC) should be reprogrammed. Accordingly, this item is considered closed.

h. Manual Valve Maintenance (Open Item 50-275/87-01-03, Closed)

A 1987 NRC team inspection identified manual valves which had not been greased or maintained by a preventative maintenance (PM) program. In discussions with the team members licensee management indicated the Operations Department would identify valves needed to be operated during accident and recovery periods, and these valves would be entered into a PM program. The licensee concluded the necessary safety system valves were included in the existing sealed valve checklists (Operating Procedure K-10 "Systems Requiring Sealed Valve Checklist"). The inspector verified OP K-10 had been revised to include stroking and lubrication of all sealed valves, once every 18 months. This item is considered closed.

No violations or deviations were identified.

12. Inservice Inspection (73051)

Several different methods of nondestructive examination were observed by the inspectors. These included liquid penetrant examination (previously written up in NRC Inspection Report 87-42), A-scan ultrasonic examination and visual examination. The inspector witnessed ultrasonic examination of a Unit 1 reactor pressure vessel stud. The required equipment and materials, specified in licensee procedure N-UT-3 "Ultrasonic Examination of Bolting with Diameter 1 Inches or Greater," were observed to be in use, and the specific area, location and extent of the examination was clearly defined. The inspector observed personnel perform a qualification test on a calibration standard made from a spare vessel stud, and observed ultrasonic equipment calibration. Transducer size, frequency, and type were in accordance with the procedure, and reject, damping and filter settings were set at minimum values. No indications in the stud examined were detected.

The inspector also observed the licensee perform visual inspection of support 15-95 on the suction piping to RHR pump 1-2. Examination of the rigid support and PSA-10 snubber was performed in accordance with ISI Procedure VT 3/4-1 "Visual Examination of Component and Piping Supports". The as-found condition of the rigid support and snubber was acceptable, however, procedural discrepancies were found. The "Figure 1" and "Figure 2" labeling was missing from the drawings of page 12 of revision 4 of the procedure. The "Hydraulic Snubbers" (Figure 1) diagram on page 12 contained the statement "...subtract the 'Z' dimension...from the measured position setting." This statement conflicts with training provided to the ISI examiners. The drawing on page 14, above Table 1, was not clear to ISI personnel interviewed by the inspector. This drawing should be revised for clarity. Finally, on Attachment 1, page 3 of 3 the "post installation verification of snubber/strut washer placement" contained check-off boxes such as "thickness, O.D. acceptable" and "remaining gap acceptable" without the procedure containing guidance on how to measure the parameters or what criteria was being used. The inspector was informed the post installation verification was not a code requirement. The licensee was made aware of the procedural discrepancies and plans to correct the procedures.

Code repair activities observed by the inspector, were previously documented in NRC Inspection Report 88-07.

No violations or deviations were identified.

13. Independent Inspection

a. System Engineering (5-37700-4)

The licensee is in the formative stages of establishing a system engineering function, and has conducted information gathering meetings with other Region V utilities. Discussions with licensee management have not established a projected completion date for the establishment and implementation of this program.

b. Post-trip Review, Events Evaluation/Root Cause Determination (5-92700-5)

During the periods January 21-22 and April 20-22, 1988, the above areas were examined by the Senior Reactor Engineer, RV. The scope of findings are discussed below:

1) Post-trip Review - Plant Administrative Procedure AP A-100 S1, Revision 3, dated July 29, 1985, was examined and records of the implementation of this procedure for three reactor trips were examined. Discussions relating to AP A-100 S1 and related plant records were held with licensee representatives and the NRC Resident Inspectors, from which the following findings and observations resulted:

Administrative Procedure AP A-100 S1 was judged to be adequate in terms of the scope of post-trip review, evaluation and documentation. The procedure provides for review and evaluation of plant and operator response as well as the authorization of plant restart (by the Plant Superintendent). The procedure includes the requirement that, under circumstances where the cause of a reactor trip is not adequately explained or where the Shift Foreman determines additional analysis is necessary, prior to restart the Plant Staff Review Committee will review the associated transient data and will approve return to power operation.

Discussions with the Resident Inspection staff revealed instances where thoroughness of post-trip review was lacking in the implementation of the AP A-100 S1. These instances are documented in recent NRC Inspection Reports. The Resident Inspection staff has also expressed concern regarding a formal process for defining and documenting specific actions required prior to plant restart. In response to the Resident Inspector's concerns, licensee management has implemented a program for action plan development and implementation. (See section 16.b of this report for licensee management commitments in this regard).

2) Events Evaluation and Root Cause Determination - In evaluating the licensee's programs in these areas, the following plant Quality Assurance and Administrative Procedures (APs) were examined and discussions relating thereto were held with responsible licensee representatives. Findings and observations resulting from the examination of procedures and discussions held with licensee representatives are discussed below:

QAP 15.B, Nonconformances, Revision dated March 10, 1988

NPAP C-12/NPG-7.1, Identification and Resolution of Problems and Nonconformances, Revision 13, dated March 22, 1988

NPAP C-16/NPG-7.4, Human Performance Evalution System, Revision 0, dated March 3, 1986

NPAP C-18/NPG-7.5, Events Investigations, Revision 0, dated July 14, 1987

NPAP C-23/NPG-7.6, Technical Review Groups, Revision 0, dated March 10, 1988

A review of the above procedures, related plant records, and discussions with responsible plant managers and supervisors resulted in the following observations and findings:

The licensee has implemented a very effective Human Performance Evaluation System (HPES) program, having been an active participant in this INPO program from the time of its initiation some two years ago. This program is intended to focus on human factor elements of plant events, and is aimed at surfacing for evaluation human factors concerns at a low threshold, e.g., "near misses". The program has an outreach aspect, wherein employees at the plant are encouraged by direct mailings, posters (with associated forms to submit written concerns), etc. in several locations within the plant and corporate offices. During the year 1987, a total of 39 HPES root cause evaluations were performed relating to various operational/maintenance events. Approximately 25 of these were in support of the dispositioning of Nonconformance Reports (NCRs).

The licensees procedures require formal root cause determination for all NCRs, of which there were approximately 135 during the year 1987. When an additional approximately 15 HPES evaluations for root cause determination are added to the number of NCRs, a total of approximately 150 events were subjected to formal root cause determination in the year 1987.

In discussions with the NRC inspector, the Plant Manager expressed his view that the threshold for formal root cause determination should be lowered to include a larger population of events beyond those for which an NCR would be initiated in accordance with current administrative procedures. (See Exit and Management Meetings section of this report for licensee management commitments in this regard).

c. Design Verification and Configuration Control: The Auxiliary Saltwater System (5-37700-1, 37700-2)

The inspector reviewed the Auxiliary Saltwater (ASW) system with respect to its design basis and how that design is implemented in the operating plant. The inspector identified the following weaknesses:

- The design basis assumptions for the ASW system have not been fully implemented into plant procedures and alarm setpoints.

As a result, plant operations have been conducted outside design basis assumptions requiring a review of the ASW system's past operability.

- The licensee did not have an adequate program for design setpoint control. As a result, the annunciator setpoint for the differential pressure (dP) high alarm across the tube side of the Component Cooling Water (CCW) heat exchanger (Hx) was raised without the appropriate design basis review.

These findings are mitigated by the licensee's current efforts in Configuration Management. Although at the time of this report the licensee's program was in its development stages, the program, as described by the licensee, would establish how design requirements and assumptions are to be implemented through plant operations, maintenance, and surveillance. In addition, it would establish procedural guidance for setpoint control.

System Description and Design Basis

The ASW system is the ultimate heat sink, designed to cool safety related loads during normal operations and following a design basis accident. The system consists of two pumps headered at their discharge located at the intake structure. They pump ocean water through two trains of 24" piping, up 85 feet over a distance of approximately 1600 feet and through the tubes of the CCW Hxs. At the discharge of the Hxs the ASW is discharged at 68 feet above sea level and cascades to the ocean. The tube side of the CCW Hx has a differential pressure transmitter with a high and low annunciation in the control room.

The inspector reviewed and discussed the ASW design with the system design engineers at the licensee's office in San Francisco. The licensee could not provide the original design calculation. Much of the original design took place in the late '60s and early '70s when complete records were not kept. The system was assembled around 1973 and tested in 1974 and 1975. In 1982, during the design verification program (DVP), the licensee performed calculations based on as-built conditions to verify the ASW system could meet its design basis.

The limiting parameter for the ASW system was determined to be CCW temperature following a design basis Loss of Coolant Accident (LOCA). The limiting component was determined to be the centrifugal charging pump lube oil coolers which was rated at up to 132 degrees F for 20 minutes. It was determined that containment could be kept below allowed temperature and pressure limits during a LOCA with two of five containment fan cooler units (CFCUs).

Licensee calculations M-305 Revision 3 assumes the following:

- An initial ASW temperature of 64 degrees F. Above 64 degrees F ocean temperature, the Technical Specifications require the use of both Hx.

- A pre-LOCA CCW temperature of 80 degrees F. This is based on the maximum normal CCW loads.

- The use of five CFCUs. All five CFCUs start on a Safety Injection System signal. Operator action would be required to shut down a CFCU at it's breaker.

- ASW flow of 10,700 gpm which is based on flow taken from the manufacturers pump curve assuming "mean low-low water" level of -2.6 feet mean sea level (MSL) and the Hx tube outlet at atmospheric pressure.

- A fouling factor, used in the heat transfer coefficient of 0.001.

The results concluded that given these conditions, one train of ASW can remove the post-LOCA heat added to the CCW system without having the CCW outlet exceeding 132° F. The licensee did not take credit for any operator action.

Design Basis vs Plant Configuration and Procedures

The inspector reviewed plant configuration and procedures against the above design basis assumptions. The following is a summary of the discrepancies found:

- The Hx dP HI alarm setpoint was 167" water whereas a clean Hx dP of 75" water was assumed in the design calculations. The following section discusses this finding in more detail.

- The Inlet bay low level alarm was set at -10' MSL whereas a level of -2.6' was assumed in the design calculations. The effect of a lower inlet bay level would be to lower suction head and consequently discharge head resulting in less flow.

- ASME Code Section XI allows pump performance to drop to 10% of its reference whereas the design calculations took pump performance from the pump curve without allowing for degradation.

- The CCW Hx shell side outlet temperature high alarm setpoint was set at 120 degrees whereas the highest normal operating temperature was assumed to be 80 degrees. If during normal operations CCW temperature rose above 80 degrees, the unit would be operating outside design assumptions.

- Plant Procedures address actions to be taken if both ASW pumps fail (cross-tie with other unit) and if CCW pumps fail (reduce system heat loads such that CCW temperature is less than 95 degrees) but not actions to be taken if one ASW train does not provide sufficient cooling.

- Plant procedures did not specifically state that operators could remove from service CFCUs during a LOCA to remove heat loads from the CCW system.

- Annunciator Response Procedure PK-0101 in step 7a. allows operators to throttle the CCW Hx tube side outlet valve if ASW pump dP is less that the Section XI limit. The procedure did not have operations notify engineering to evaluate the operability of the pump.

The first three findings listed raised questions of the ASW system's ability to perform its function under conditions less conservative than assumed in its design basis calculations.

The inspector discussed these findings with the Project Engineer for Diablo Canyon who committed to provide a written analysis of ASW system operability to the NRC by June 7, 1988. Pending a review of the analysis this item is Unresolved (Open Item 50-275/88-11-02).

These findings also show that many design assumptions were not incorporated into plant operations. As corrective action for the ASW system, the licensee plans to establish what design assumptions need to be implemented and revise procedures, alarm setpoints, instrumentation and documentation as necessary. To address these concerns on a larger scale, the licensee had initiated a Configuration Management program in November 1987. As described by the licensee, this program would address the issue of design basis implementation in plant operations. Although the significance of these findings as related to general design basis understanding and implementation is mitigated by the Configuration Management Program, continued attention needs to be focused on this issue.

Setpoint Control

The inspector investigated the basis for the annunciator setpoint for dP across the CCW Hx tubes, pressure switches PS 45 and 46. It was determined that the setpoint of 167" of water had been established in March 1987 following a design change to install pressure transmitters and switches with a higher range. The design change had been initiated in 1985 by the operations department since Hx fouling dP across the Hxs was routinely above the existing setpoint of 110" during normal operations. The engineering reviewers of the design change erroneously determined that the change did not affect equipment important to safety or equipment important to environmental quality. In the general notes contained in the design change package Project Engineering authorized Operations to revise the setpoints for PS 45 and 46 but did not give them specific guidance except to state that Operations should follow up by revising drawing 101938 (Non-Safety Instrument Setpoints) with a field change.

Operations revised the setpoint from 110" to 167" basing the revision on a calculation of only one limiting condition; the maximum flow velocity through the tubes. The flow velocity

according to the vendor should be kept below 7 feet per second; 167" correlates to 6.8 fps.

Upon subsequent investigation, the inspector found that safety related Drawing Nos. 060836 (for Unit 1) and 061236 (for Unit 2), "Instrument Setpoint Requirements" Table II lists the high alarm setpoint for PS 45 and 46 to be 4 psid which corresponds to 110.7". The cover note to the drawing states "Table II of this drawing lists other non-instrument Class 1A setpoints which engineering has determined to be appropriate to meet various FSAR commitments." This design drawing was not reviewed or changed when the setpoints of PS 45 and 46 where changed. This is a failure of Engineering not to reevaluate the basis for the original setpoint and is an apparent violation of Criterion III, "Design Control," of 10 CFR 50 Appendix B but will be treated as unresolved until the significance of the ASW/CCW systems operating with a 167" differential pressure setpoint is resolved. Following the meeting of the Technical Review Group for the ASW system Non Conformance Report, Operations put an administrative limit on CCW Hx tube side dP of 110" pending the resolution of the basis for the 110" setpoint. Subsequently, it was determined that the dP setpoints in Drawing Nos. 060836 and 061236 to control the low alarm setpoint satisfied the FSAR commitment for a control room alarm on ASW piping failure. Regardless, system performance is directly effected by Hx fouling and requires setpoint control. The licensee was in the final stages of a comprehensive revision to the setpoint control program at the time of this finding. These revisions appear adequate to ensure that important setpoints are reviewed against the design basis.

d. Cleanliness Control Problems (5-92700-4)

In previous resident inspector report (Inspection Report 50-275/88-07), two cleanliness problems were identified during the performance of refueling outage work. The two areas examined previously were the removal of thermocouple connoseals on March 21 and spare control rod drive mechanism work on the removal of the reactor vessel head on April 6, 1988.

During this reporting period the control of cleanliness problems continued. On April 9, 1988, quality control (QC) personnel issued a stop work on CRDM cleanliness requirements. The stop work was lifted later that day after corrective action was taken. The action consisted of erecting barriers around the refueling cavity that were shown later to be ineffective. Additionally a memo was issued by engineering to the engineering task coordinators regarding cleanliness controls. Subsequent events showed that this memorandum was ineffective in precluding further occurrences.

On April 12, 1988, QC inspectors identified that cutting fluid and chips were being allowed to enter crevice areas on the reactor vessel head. Accordingly, a stop work was issued. Subsequently, the licensee implemented corrective actions. These corrective actions consisted of cleaning the crevices and revising the procedure for cutting to include a QC holdpoint to verify barriers

were installed. Corrective actions did not include personnel reinstruction even though the procedure used had a specific caution note requiring steps be taken to preclude fluids from entering the crevices.

On April 22, 1988, during the attempt to reinstall the upper internals, work was stopped by the refueling crew due to the sighting of debris on the upper internals which was initially reported as tools (pliers, nuts, and washers). The debris was retrieved and determined to be a broken "tie wrap" (a plastic strap ordinarily used to secure electrical cable to cable trays) and paint chips.

The inspector attended the licensee's corrective action meeting on April 22, 1988. The inspector entered containment with the engineer assigned the responsibility to determine the probable source of the debris on the upper internals.

The engineers in charge of the job did not "save the evidence" upon debris retrieval, but rather had it placed in radioactive waste. It was retrieved by the licensee and the inspector observed that the tie wrap looked old (yellowing in color as opposed to new white) and the paint chips were yellow paint. The conclusion drawn was that the tie wrap probably came from the reactor vessel head and its cable trays. The inspector then examined the work area on top of the reactor vessel head and noted several unsatisfactory conditions. The removed head was stored immediately adjacent to the refueling cavity; most of the components on the head do not hang over the cavity, but a portion of the cable tray area does hang over the pool. The tie wrap found on the internals was directly under the head area cable tray. The inspector found additional broken tie wraps in the cable tray area which had the potential to fall.

Additionally, on the upper area of the head (where work had been underway to remove and replace digital rod position indicator (DRPI) stacks for CRDM weld repair access) the inspector found a great deal of dirt (up to 1/4" thick) including broken microphone ceramics abandoned in place since pre-operational testing. The engineer in charge of that work explained that prior to removing any DRPI coils, the local area around the DRPI coil was vacuumed, and that any dirt dislodged would fall straight down and not into the refueling cavity. However, he further explained that one of the interlocking steel plates in that same area had been inadvertently kicked, fell, bounced off a structure, and ended up in the refueling cavity pool, and was yet to be retrieved. Therefore, the logic that dirt and debris would only fall straight down appeared to be faulted.

The inspector discussed the cleanliness situation with the engineers in containment and with the outage manager that evening. All areas were recleaned and verified clean prior to recommencing reactor assembly.

On May 10, 1988, licensee personnel identified cleanliness control deficiencies in the Unit 1 Spent Fuel Pool including an incomplete tool log. Corrective actions consisted of completing the tool log.

Cleanliness control problems were identified by the NRC from March 21 to April 22, 1988. Additionally, QC personnel issued two stop works on the same subject and licensee identification of problems continue.

The licensee's actions up to the point of the inspectors involvement were ineffective in that they did not identify additional debris on the reactor vessel head which could be easily dislodged and find its way into the refueling cavity and possibly reactor vessel. This is a significant condition, because debris in the refueling cavity or reactor vessel could impact reactor operations and fuel conditions. This was true despite memorandums of instruction by the engineering manager and increased QC surveillance. The failure to take timely effective corrective action to preclude recurrences of cleanliness deficiencies is an apparent violation of 10 CFR 50 Appendix B criterion XVI (Item 50-275/88-11-03).

e. Pressurizer Surge Line Movement

Trojan Nuclear Power Plant, located in Region V, has experienced movement of the pressurizer surge line possibly due to thermal stratification.

The resident inspector contacted the responsible engineer at Diablo Canyon to determine if evidence of movement or lack of it was available for Diablo Canyon. The licensee had taken measurements of the pressurizer surge line in Unit 1 relative to structure in 1983, 1986, and during the current refueling outage. Review of the measurements showed essentially no movement of the pressurizer surge line relative to structure. At the close of the inspection report period the licensee indicated that some evidence such as pipe burnishing indicated that in the hot condition the pressurizer surge line may be contacting pipe whip restraints. The licensee was analyzing the findings, considering the addition of inservice instrumentation to detect thermal stratification, and planned to pursue resolution with Westinghouse. The licensee's resolution will be followed as open item 50-275/88-11-04).

One violations and no deviations were identified

14. Containment Integrated Leak Rate Test (ILRT) (70307 and 70313)

a. Procedure Review

The inspector reviewed the Unit 1 and 2 ILRT procedures as described in the licensee's Surveillance Test Procedure STP M-7, Revision 7 of May 5, 1988, (and the Temporary Change Notices issued during this inspection) entitled, "Containment Integrated Leakage Rate Test ILRT), Type A." This review was to ascertain compliance with plant

Technical Specifications, regulatory requirements, and applicable industrial standards as stated in the following documents:

- Diablo Canyon Power Plant, Units 1 and 2, Updated Final Safety Analysis Report (FSAR), Sections 3.8.1.7.2, 3.8.1.7,4, and 6.2.1.4.

- Diablo Canyon Power Plant, Units 1 and 2, Technical Specifications, Section 3/4.6.1.2, "Containment Leakage", and 3/4.6.1.6, "Containment Structural Integrity."

- Appendix J to 10 CFR 50, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors."

- American National Standard, "Leakage-Rate Testing of Containment Structures for Nuclear Reactors," ANSI N45.4-1972.

- Topical Report BN-TOP-1, Revision 1, "Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants," Bechtel Corporation, dated November 1, 1972.

- American National Standard, "Containment System Leakage Testing Requirements," ANSI/ANS-56.8-1981.

- IE Information Notice No. 85-71, "Containment Integrated Leak Rate Tests."

During this procedure review, the inspector made the following observations:

The procedure requires the containment liner weld channels to be vented to the containment atmosphere during the test, as is required. The inspector noted that, at other plants, these channels have not been vented during the test and additional safety review by the Office of Nuclear Reactor Regulation (NRR) has been required to resolve this issue.

There is a discrepancy in the procedure concerning the test acceptance criteria. Section 5.3.3 of the procedure states that, in accordance with the provisions of BN-TOP-1, Rev. 1, the end of test 95% upper confidence limit (UCL) for the calculated leakage rate shall be less than La. However, in Appendix F, on the "Acceptance Criteria Check Form-Data Sheet," the limit is 0.75 La, rather than La. The NRC's position is that the regulation, Appendix J to 10 CFR 50, requires the acceptance criterion to be 0.75 La, as does the NRC's Topical Report Evaluation, dated January 15, 1973, which accepted BN-TOP-1. For the present test, the acceptance criterion of 0.75 La was in fact satisfied. Nevertheless, the inspector informed the licensee that section 5.3.3 was inconsistent with acceptance criteria requirements.

Section 5.4 and Appendix F of the procedure also specify that, for a 24-hour duration full pressure test according to 10 CFR 50, Appendix

J and ANSI N45.4-1972, the calculated leakage rate shall be less than 0.75 La. However, section III.A.3.(c) of Appendix J to 10 CFR 50 requires the calculated leakage rate to be corrected for error. Although no particular method is generally required, many licensees use a 95% UCL, similar to the BN-TOP-1 procedure, to account for error. For the present test, the BN-TOP-1 procedure was used. The licensee has marked up the procedure with associated clarifications to be included in the next normal revision.

b. Review of Records

The inspector reviewed calibration records for the instrumentation used in the ILRT. That is, the twenty-four resistance temperature detectors (RTDs), six dew point temperature sensors (dew cells), and two pressure gauges used to measure containment air mass, and the flow element used to measure the induced leak during the verification portion of the ILRT. All instruments had been calibrated within the last six months with NBS traceability. In situ checking of the instrumentation had been performed within one month of the test.

Although the procedure did not provide instructions for containment temperature survey before the test to verify temperature sensor locations, such a survey was conducted, as observed by the inspector and discussed in the following section. The inspector requested that the survey results be included in the licensee's test report to the NRC, which is due within three months of ILRT completion. Because a temperature survey will probably be performed on Unit 2 in preparation for the Unit 2 ILRT planned for Fall 1988, the licensee should consider developing a written procedure for this activity.

c. Observation of Work and Work Activities

Prior to the ILRT, the inspector observed a portion of the visual inspection of the inner surface of the containment, including the containment liner. No evidence of structural deterioration, apparent changes in appearance, or other abnormal degradation were found.

The inspector observed the containment pressurization equipment, consisting of eight air compressors, two after-coolers, two air dryers, and connecting hoses and equipment. During the containment pressurization phase, two of the air compressors were out-of-service, which somewhat slowed containment pressurization. Also, during most of the pressurization phase, one air dryer failed to work. The resulting higher moisture content of the air entering containment may have contributed to high relative humidity in the containment, which apparently caused water condensation on dew cell No. 2 at the end of the test (during the verification phase). This was the apparent cause of erratic readings which resulted in removal of the dew cell from service. This is discussed further below.

The inspector witnessed a portion of the pre-test containment temperature survey. Two surveys were actually performed; one with

the containment fan cooler units running, and one without. This information gave the licensee the option to either run or not run the fan coolers during the ILRT, as the validity of RTD placement could be confirmed. During this ILRT, the licensee chose to not run the fan coolers, as running then introduces additional heat sources or heat sinks (depending on cooling water flow and temperature) which are difficult to control. The licensee stated that the temperature survey did confirm the validity of RTD positioning and weighting factors. The inspector requested that the survey data be included in the licensee's report to the NRC.

The inspector witnessed selected portions of the following ILRT activities listed below and noted the time expended to perform each:

- Initial pressurization to 47 psig + 2/-0 psig, approximately 12 hours.
- ILRT stabilization, approximately 4.5 hours.
- ILRT data acquisition.
- Performance of ILRT, approximately 42 hours, including a failed initial test, as discussed below.
- Leak rate verification test stabilization, approximately 1 hour.
- Leakage rate verification test, approximately 8 hours, with an imposed leak rate of 7.5 standard cubic feet per minute (SCFM), which equals La, which is 0.1% per day.

Various electrical and mechanical penetrations were inspected. Because the typical containment isolation valve was vented and drained both inside and outside containment, the licensee was able to fit balloons over the ends of the vent lines outside containment, so that balloon inflation would indicate leakage pasted the containment isolation valve seats. The licensee checked these balloons approximately every two hours during the test, for excessive leaks, but did not find any through the use of this device.

During the test stabilization period, RTD No. 21 failed high, suddenly reading 121 degrees F where it and other nearby RTDs has been reading in the 60s. Dew cell No. 3 exhibited erratic readings during the same period. Both sensors had their weighting factors set to zero and their original weighting factors were reassigned to other nearby sensors for the duration of the test.

A few hours after starting the ILRT itself, it became apparent that the containment was leaking excessively. After about seven hours, the measured leakage rate (Lam) had stabilized at a value of approximately 0.118% per day, whereas the acceptance criterion, 0.75 La, equaled 0.075% per day (La=0.1% per day). Licensee personnel searched exhaustively for leaks using soap bubble solution (Snoop)

and other methods. Eventually they found that at one of the 48-inch purge line penetrations, there was a pressure of 47 psig (or current containment pressure) between the two closed isolation valves. This indicated that the valve inside containment (RCV-11) was either not closed completely or was leaking very badly. However, during the ILRT, the valves had been locally (type C) leakage rate tested only a few days earlier and had passed that test easily. The valve outside containment (RCV-12) was found to have significant packing leakage and some seat leakage.

Another purge isolation valve outside containment (FCV-661) in a different penetration was also found to have significant packing leakage, which would indicate a leaking inside containment isolation valve on this penetration.

About 15 hours into the test, the licensee opened a vent valve (approximately one inch in diameter) between RCV-11 and -12, in an attempt to depressurize the space between the valves. After approximately 15 minutes, the vent valve was closed and the attempt abandoned, because the pressure between the valves had not decreased more than a few psi. This confirmed that valve RCV-11 was indeed not limiting leakage in any substantial way.

Subsequently, the licensee took actions to eliminate or reduce known leaks, primarily by tightening down on valve packing. When that did not reduce leakage sufficiently on valve RCV-12, the licensee took the unusual step of adding one or more additional packing rings on the valve stem and tightened down on those. This step nearly eliminated packing leaks on valve RCV-12.

When the licensee took actions to reduce containment leakage rate by repairing, adjusting, or altering the containment pressure boundary, this caused the test to be considered a failure, in accordance with section III.A.1.(a) of Appendix J to 10 CFR 50. In other words, the containment was leaking in excess of the allowable limit, and the only way to pass the test was to take steps to eliminate leaks. The licensee's procedure STP M-7, Rev. 7, also refers to this circumstance as "the initial unacceptable ILRT," which must then be followed by another, successful ILRT.

After reducing leaks, the licensee restarted the test (or started a new test) at 8:44 p.m. on May 19, 1988, approximately 28 hours after the initial start of the test. Using the methodology of BN-TOP-1, the test was successfully completed some 12 hours later. There was then some delay in establishing the superimposed leakage rate flow out of the containment for the supplemental or verification test. The licensee has run approximately 200 feet of small-diameter (0.75 inch) plastic tubing from a containment penetration to the two Volumetrics thermal mass flow meters installed in instrumentation cabinet in the DAS (data acquisition system) shed. This long, narrow tubing could only pass approximately 5 scfm, short of the needed 7.5 scfm. Therefore, the licensee resorted to a backup mechanical rotometer which was placed close to the containment penetration to allow the needed flow. With this delay and the

required (by BN-TOP-1) one hour stabilization period, the verification test was started at 11:29 a.m. on May 20, 1988. During the verification test, dew cell No. 2 exhibited erratic behavior which was appearing to cause the test to fail to meet its acceptance criteria. When the licensee zeroed its weighting factor and reassigned the original weighting factor to other dew cells, the verification test passed. The inspector's preliminary conclusion was that this action was acceptable, but, because it took place after the inspector completed his inspection and left the site, NRC review of the licensee's justification for zeroing dew cell No. 2, contained in the licensee's report to the NRC, will determine the final acceptability of the action.

The inspector performed an independent computer calculation of leakage rates to verify that the licensee's computer program was correctly calculating leakage rates. The inspector's calculations did indeed verify this.

The licensee's preliminary results for the final 12 hour Type A test, which did not include Type C additions, was a total time calculated leakage rate of approximately 0.02% per day with 95% upper confidence limit (UCL) of approximately 0.071% per day. The licensee's maximum allowable leakage rate (0.75La) for this test was 0.075% per day. An approximately 8 hour verification test was performed with an imposed leak rate of approximately 7.5 SCFM or 0.1% per day of containment air mass. The licensee's verification test produced a total time calculated leakage rate that fell within the test acceptance criteria of approximately 0.095 to 0.145% per day. These preliminary results appear to be within the allowed acceptance criteria.

d. Conclusions

At the exit meeting held on March 20, 1988, the inspector stated that the failed initial test would require, in accordance with section III.A. 6 of Appendix J to 10 CFR 50 and facility Technical Specification 4.6.1.2.b., that the schedule for subsequent Type A test be reviewed and approved by the NRC. If two consecutive Type A test failures should occur, then a Type A test shall be performed at each plant refueling outage or every 18 months, whichever occurs first, until two consecutive Type A tests pass, whereupon the normal test schedule may be resumed. However, the inspector emphasized that, in cases (like this test) where failure can be attributed to a few specific penetrations, the NRC encourages the licensee to propose, as a formal exemption from the regulation, a corrective action plan which would address the problem penetrations in lieu of increased Type A test frequency. Such exemptions are judged on a case-by-case basis and are not automatic; it is also unlikely that the licensee would be relieved from the first test on the increased frequency schedule, and that a test would likely have to be passed successfully before an exemption would be granted.

e. Subsequent Information

After depressurizing the containment, after completing the ILRT, the licensee conducted a Type C (local leakage rate) test on RCV-11 and -12, which passed with no repairs or adjustments to the valves. The licensee has preliminarily determined that RCV-11 (inside containment) may have been installed, maintained, and or tested improperly so that the valve leaks excessively during an ILRT (and so would during a LOCA), but not during the Type C test, which is performed by pressurizing the volume between the two isolation valves in the penetration. Thus, the Type C test measures the leakage rate through RCV-11 in a direction opposite to that which would occur during LOCA. It has been thought that this "reverse-direction" testing was equivalent to testing in the "forward" direction. The licensee also found that the inside containment isolation in the second purge line, FCV-660, had the same potential problem, as did the congruent valves in Unit 2. All four valves were declared inoperable, and Technical Specifications were satisfied. Followup will be done under routine inspection.

No violations or deviations were identified.

15. Examination of Instrumentation and Controls (I&C)

A special inspection was conducted to examine the area of instrumentation and controls. The inspection was performed by an NRC contractor from EG&G Idaho experienced in the I&C area.

The results of the examination are presented in detail as an enclosure to this report.

Areas for improvement identified by the inspector and communicated to the licensee at an exit interview conducted on May 19, 1988, included the following:

- The adequacy of procedures was found to be mixed. Repetively performed surveillance test procedures (STP's) were generally found to be detailed and adequate. There was one notable exception and that was STP I-33B which is performed every refueling outage for time response testing. STP I-33B was poorly prepared despite being in preparation for several months. Loop test procedures were not addressed since they were already an issue which the licensee has laid out a plan to correct. Corrective and investigative maintenance procedures in the form of work orders were mixed in their quality from good to poor.

- The licensee was cautioned to ensure that procedure review was enhanced to ensure a critical review prior to issuance and to ensure a conformance to a uniform standard of detail. The licensee stated that additional personnel (5) had been hired to achieve procedure improvements and that plans were in place for revising writers guides for future procedures to satisfy both NRC and INPO initiatives in this area.

The issue of poor procedures in the I&C area and the untimely correction of those problems has been the subject of previous inspections.

The recent licensee action to apply resources to the problem is encouraging. The effectiveness of and timeliness of the licensee's future actions will continue to be monitored in future inspections.

16. Exit

a. Routine Exit (30703)

On May 27, 1988, 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.

b. Exit and Management Meetings (30702)

Additionally, in discussions with senior plant management on April 22, 1988, the Plant Manager committed to the following:

1) An action plan will be developed by May 6, 1988, and will address the following:

- The current practice for the development of event response action plans, including schedule for implementation, will be incorporated in new or revised plant administrative procedure(s).

- Criteria will be incorporated in revised or new administrative procedure(s) to lower the threshold for events which will be subjected to formal root cause determination.

- Specific consideration will be given to revising current Quality Control/Administrative Procedures to require root cause determination in the dispositioning of Quality Evaluation (QE) reports, of which there were a total of approximately 660 in the year 1987.

Enclosure to
Inspection Rept.
50-275/88-11
50-323/88-10

I&C MAINTENANCE EVALUATION OF THE DIABLO CANYON POWER PLANT

1.0 INTRODUCTION

An evaluation of the Diablo Canyon Power Plant (DCPP) Instrumentation and Control (I&C) Maintenance Department was performed during the periods of March 28 through April 8, and May 3 through May 19, 1988. The guidelines used for this evaluation were the United States Nuclear Regulatory Commission (NRC) Inspection Procedures 52051, 52053, 62704, and 62705. Some areas of concern with respect to the preparation and planning of procedures and work orders were identified.

Three primary areas of I&C maintenance activities were the focus of this inspection:

1) Are the I&C technicians technically competent?

2) Are the procedures used by the I&C technicians good procedures?

3) Do the technicians follow the procedures?

Another question was raised during the inspection with regards to Quality Control (QC) involvement with the I&C work activities.

Most of the inspection effort was directed at the I&C maintenance groups which dealt with the plant protection systems and other systems important to safety. Therefore, the caliber of the technicians and quality of the work packages were expected to be the best representations of the I&C maintenance activities.

2.0 CAPABILITIES OF THE TECHNICIANS

The maintenance and surveillance activities performed by the technicians, for the most part, were observed to be done in a satisfactory manner with the technicians displaying an adequate knowledge of the tasks required within the work packages. The technicians spent time acquainting themselves with the proper background material and systems information to gain an understanding of the tasks to be performed and to obtain the necessary tools and test equipment prior to beginning their work activities. The efforts of removing the device or system from service,

the corrective maintenance or surveillance activities, and the task of returning the device or system back in service were all performed in an acceptable manner.

A few of the technicians observed were outstanding in the skills they possessed or their work habits. A few others were observed as either somewhat lethargic or almost recklessly fast. Overall however, the technicians seemed genuinely interested in doing a good job and were conscientious and professional with their work. No unsatisfactory work was observed due to the skills of the technicians.

3.0 ADEQUACY OF THE PROCEDURES

During this inspection, 28 activities associated with procedures were evaluated. Nine of the activities were Loop Tests, 11 of the activities were Surveillance Tests (STPs),five of the activities were for Corrective Maintenance, and three procedures were reviewed as examples of what some DCPP I&C personnel considered good procedures. For all but the three example procedures, the work activities of the technicians as well as the adequacy of the procedures were evaluated. No work activities were observed with respect to the three example procedures, only the procedures themselves were reviewed.

3.1 Loop Test Procedures

Since the Loop Test Procedures have received previous attention which has identified them as being inadequate, and a program to update and improve the Loop Tests has been initiated, not much emphasis was placed on these procedures. The work activities associated with these procedures was the main interest of the Loop Tests, and the technicians were able to perform the tests in spite of the poor procedures, primarily due to their familiarity with the system.

3.2 Surveillance Test Procedures

The adequacy of the STPs was found to vary. Some of the STPs, such as those performed on a frequent basis, contain adequate detail and instructions to efficiently complete the task. However, even DCPP personnel have recognized a deficiency in the quality of some of the STP procedures and have implemented a program to update them. Examples of the plant awareness of the inadequacies of the procedures are the rewriting of STP-I-8B for the Reactor Coolant Flow Transmitters and STP-I-33B for Time Response Testing of the Reactor Trip and Engineered Safety Features (ESF) Logic. The 8B and 33B procedures required rewriting because of a lack of detail and were confusing in giving direction to the technicians.

STP-I-8B is being rewritten to consolidate several procedures and make the procedure more concise. The writing of this procedure is utilizing several concepts, such as human factors, and will be used as a model for

procedures rewritten in the future. A review of the rough draft of this procedure indicates a positive step toward standardizing and improving the procedures.

A considerable amount of time was spent reviewing STP-I-33B and observing the technicians activities while working on this task. Because this procedure was a new procedure (approved 4/22/88) and time response testing of the safety systems is important, it was felt that this procedure should be representative of the type of procedure DCPP plans to produce in the future. However, this new procedure (admittedly better than the old 33B procedure) had several deficiencies and the I&C personnel admit that the procedure is not a good one despite having spent seven months rewriting the procedure.

The most significant problems with the new 33B procedure were a lack of specifics and clarity. The prerequisites were vague and incomplete in describing the equipment needed to set up the test, (i.e.,"5. Toggle switch(s)." vs the actual number of switches required). The instructions for setting up the test equipment were so limited that a technician performing the test for the first time, probably couldn't set up the equipment without assistance. Even technicians that had previously performed the test had difficulties and had to make several phone calls to resolve questions. The procedure should contain enough detail that the technicians can perform the tasks without requiring prior experience with that particular procedure.

An example of how a lack of adequate research and a lack of detail in the procedures creates problems was observed during the performance of Part 10 of the 33B procedure which measures the time response for the Overtemperature Delta T Reactor Trip. Initially, the technicians could not obtain repeatable results for this test. An on-the-spot tailboard between a supervising technician and engineer determined that the problem was due to a module failure. A Work Order was generated to check the module and it was determined that the module had not failed. Further investigation determined the problem to be incorrect values given in the procedure for simulating the hot leg and cold leg temperature inputs. For a test as important as the safety system time response testing, adequate research and systems knowledge should ensure that the primary system temperature parameters are correctly entered in the procedure.

The research required to write a detailed procedure might prevent some of this type of confusion and delay. Also, dry running a new procedure can sometimes help in debugging the document so that the final result is a procedure that is correct and efficient to use. The I&C Manager indicated that the I&C policy is currently to dry run new and revised procedures as much as practicable.

The DCPP I&C Department agrees that the new STP-I-33B procedure is not a good model for future procedures and was not intended to be. However, to spend seven months rewriting a procedure that is known to be deficient

appears to be self defeating. This effort indicates either a lack of commitment to having good procedures or an only good enough to get by approach. A logical conclusion would be that the procedure was not given enough emphasis to complete properly and when it came time to perform the test, the procedure was signed off as good enough so the task could proceed.

3.3 Corrective Maintenance

Of the five Corrective Maintenance activities observed, one of the Work Orders represented an excellent effort of planning and procedural preparation, and one of the Work Orders contained elements which are considered inadequate and unsatisfactory. The other three Work Orders satisfactorily represent something in between these other two extremes.

The Corrective Maintenance activity associated with the Unit 2 Pressurizer Pressure Transmitter (PT-474) contained detailed descriptions not found in most of the other DCPP maintenance documents. Perhaps this was due to the high visibility of the consequences of not performing this task in a rigid manner. However, the tasks performed, i.e., opening valves, returning to service, etc., were explained very explicitly in the Work Order for this activity.

An example of a Corrective Maintenance Work Order with virtually no planning or direction for the technicians was observed during the work performed on the pressure switches, PS-45/PS-46, for the CCW Heat Exchangers. This Corrective Maintenance was generated by Engineering at the request of Operations to reduce the number of nuisance alarms in the control room. When the request to perform the work was denied by Operations because it didn't fix their problem, the engineers changed the Work Order. The module requiring the correction did not respond as expected and so another Work Order was written to "GIVE DIRECTION TO REPLACE 1PS-46A/46B" and then the directions were to "REPLACE 1PS-46A/46B AS REQUIRED TO ENSURE PROPER LOOP OPERATION." When the technicians tried to complete this task, they discovered that the power supply was common to other systems. The technicians researched drawings and other documentation to determine the effects that disturbing the power supply would have on other systems in the plant. It was determined that the work could not continue and was scheduled for a later date. Operations later informed the technicians that the system believed to be affected was not in service anyway, so the work could have been performed at the originally scheduled date.

This research should have been performed at the planning stage by an engineer, a supervising technician, or the planner. The I&C Technicians, besides performing their technical tasks, should not be totally responsible for determining the effects their efforts have on the overall plant. They should be given direction through the use of detailed, informative procedures and work orders.

3.4 Example Procedures

The three procedures reviewed as examples of what responsible I&C personnel felt were good procedures were maintenance procedures. Procedure I&C MP 4.1-1A for checking the calibration on an audio oscillator and power amplifier is an example of an excellent procedure. This procedure contains specific prerequisites, precautions, and instructions, and was approved in 1982. This indicates that the ability to prepare good procedures has been available at DCPP in the past. In updating the other I&C procedures, some of the features of this procedure should be considered.

4.0 ADHERENCE TO PROCEDURES

For most of the Loop Tests, STPs, and Corrective Maintenance Work Orders, the technicians familiarized themselves with the tasks to be performed and then performed the tasks per the procedures. In several cases the technicians appeared to be so familiar with the procedure that it was difficult to determine if the technicians were actually following the procedures or simply filling in the test data.

The only instances where the technicians obviously did not follow the procedures involved transferring test data from strip chart recorders to the data blanks in the procedure. This occurred during STP-I-33B, where not only was the data not properly transcribed, but the strip chart recordings were not kept with the work package where the data could be reviewed. On site follow-up showed this problem to be one of lax follow through of administrative controls of data, i.e., this problem had no technical significance however.

QUALITY CONTROL INVOLVEMENT WITH I&C WORK ACTIVITIES

While reviewing the I&C work packages and observing I&C technicians in the field, an apparent lack of QC involvement was noted. Several of the I&C technicians stated that they didn't feel that the QC personnel were qualified to review I&C work anyway. Therefore, some time was spent reviewing the process by which QC determines which jobs are inspected, and how many they actually look at.

When the Work Orders are generated by the I&C planners, a QC planner reviews the package using a standard checklist. If the package contains the information required in the checklist then QC may choose to perform an inspection or surveillance on the work activity. This checklist method seems to be a reasonable attempt at giving all work packages the same level of review and ensuring inspections are performed on a consistent basis.

A computer search was done to determine how many Work Orders were reviewed and how many inspections and surveillances were performed on those Work Orders. Data was obtained for the time periods from March 28, 1988 through April 8, 1988. and from May 2, 1988 through May 13, 1988 During the March 28 through April 8 time period, 58 packages were reviewed with nine inspections and 10 surveillances performed. For the time period from May 2 through May 13, 74 packages were reviewed with 15 inspections and five surveillances performed. Both of these samples indicate that QC is involved with approximately 30% of the jobs in the field. No attempts were made to determine how intense or effective these inspections and surveillances were, but it appears that the same amount of involvement occurred during both time periods. If inspections were required, then not as many surveillances were performed. When there were few inspections, then more surveillances were performed.

This amount of involvement (30%) appears to be a reasonable amount of review.

6.0 CONCLUSIONS

The evaluation of the I&C Maintenance Department was performed to determine if the organization was operating in an effective manner and in the best way possible.

The technicians, both DCPP and contractors, performed their tasks with an average level of ability and professionalism.

The procedures used by the I&C Maintenance Department consist of both good and bad procedures. Some of the STPs and maintenance procedures represent adequate, detailed procedures. However, some of the STP procedures and Loop Tests, and some of the Work Orders for Corrective Maintenance, lack detail and direction. Good procedures and proper planning can not only give instructions and directions for performing a task, they can also prevent the work activities from being performed out of control.

DCPP agrees that some of the procedures require attention and have implemented several programs to update and improve the procedures. However, there are no strong perceptions that these programs have a total commitment by the plant staff and that the procedures will be updated in a timely manner.

The technicians adequately followed the procedures, especially when critical functions or sensitive tasks were being performed.

APPENDIX A

The following people were the primary contacts while performing this evaluation.

W. G. Crockett	I&C Maintenance Manager
C. A. Wetter	I&C Maintenance General Foreman
J. J. McCann	Instrument Maintenance Foreman
A. G. Moore	Instrument Maintenance Foreman
J. R. Tinlin	Instrument Maintenance Foreman
W. L. Brown	Supervising Technician
D. D. Malone	Compliance Engineer
L. Kase	I&C Planner
J. Hickman	I&C Planner
D. R. Geske	Lead QC Specialist
R. S. Fairchild	QC Specialist
S. V. Noe	QC Specialist

Other persons interviewed were the I&C Maintenance Technicians and the management personnel attending the entrance and exit meetings.

APPENDIX B.

Work Order	Unit	Activity	System
R0039357	2	STP-I-16A	SSPS Logic Train B
C0013865	1	Corrective Maintenance	PS-46A CCW
R0005365	1	STP-I-54	PT-506 Main Turbine
R0004749	1	STP-I-8B3	FT-444 RCS
R0004703	1	STP-I-8B3	FT-445 RCS
R0004798	1	STP-I-8B3	FT-446 RCS
R0010540	1	STP-I-91B	Thermocouple Monitoring System
R0022494	1	LC-21-13B	LS-207 DG 1-2
R0021550	1	LT-21-18F	TS-96 DG 1-2
R0022508	1	LT-21-18G	TS-97 DG 1-2
R0020429	1	STP-I-6B3	PT-474 Pressurizer
R0021791	2	LC-10-4	FIC-641B RHR 2-2
C0030212	2	Corrective Maintenance	PT-474 Pressurizer
R0024828	1	LCV-110 (3-109)	PC-86 Aux Feed
R0022327	1	LC-7-221A	TM-411D Delta T Deviation
R0022328	1	LC-7-221B	TM-421D Delta T Deviation
R0022329	1	LC-7-221C	TM-431D Delta T Deviation
R0022295	1	LC-7-221D	TM-441D Delta T Deviation
R0005035	1	STP-I-72B	ENST-1 Seismic Trip
R0005034	1	STP-I-72B	ENST-2 Seismic Trip
R0025281	1	STP-I-72B	ENST-3 Seismic Trip
R0010982	1	STP-I-33B1	Reactor Trip & ESF Logic

Work Order	Unit	Activity	System
C0032061	1	Corrective Maintenance	Support for STP-I-33B1
C0032191	1	Corrective Maintenance	TC-411A Module Check
C0026709	1	Corrective Maintenance	Lead/Lag Modules
N/A	N/A	I&C MP 4.1-1A	Test Equipment Calibration
N/A	N/A	MP I-2.28-1	RVRLIS Calibration
N/A	N/A	MP I-2.14-2	Reactor Coolant RTDs