U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/87-10 and 50-323/87-09

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: February 8, 1987 through March 14, 1987

Inspectors: _____ 3/30/87
L. M. Padovan, Resident Inspector — Date Signed

_____ 3/30/87
K. E. Johnston, Resident Inspector — Date Signed

_____ 3/30/87
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Approved by: _____ 3/30/87
M. M. Mendonca, Chief, Reactor Projects Section 1 — Date Signed


Summary:

Inspection from February 8, 1987 through March 14, 1987 (Report Nos. 50-275/87-10 and 50-323/87-09)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of on-site events, open items, and licensee event reports (LERs). Inspection of Unit 2 low density spent fuel racks was also performed. Inspection Procedures 30702, 30703, 61702, 61707, 61726, 62702, 62703, 71707, 71710, 92701, and 93702 were applied during this inspection.

Results of Inspection: No violations or deviations were identified.

DETAILS

1. Persons Contacted

J. D. Shiffer, Vice President Nuclear Power Generation
R. C. Thornberry, Plant Manager
*J. A. Sexton, Assistant Plant Manager, Plant Superintendent
*J. M. Gisclon, Assistant Plant Manager for Technical Services
*J. D. Townsend, Assistant Plant Manager for Support Services
*D. B. Miklush, Maintenance Manager
W. G. Crockett, Instrumentation and Control Manager
*L. F. Womack, Operations Manager
*T. L. Grebel, Regulatory Compliance Supervisor
S. R. Fridley, Senior Operations Supervisor
R. S. Weinberg, News Service Representative
*R. P. Powers, Acting QC Manager
*S. G. Banton, Engineering Manager

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

*Denotes those attending the exit interview.

2. Operational Safety Verification

a. General

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

On a daily basis, the inspectors observed control room activities to verify compliance with selected Limiting Conditions for Operation (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:

(1) General plant and equipment conditions.

(2) Fire hazards and fire fighting equipment.

(3) Radiation protection controls.

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

(5) Interiors of electrical and control panels.

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

(7) Plant housekeeping and cleanliness.

(8) Essential safety feature equipment alignment and conditions.

(9) 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. Seismic Interaction Issues

On routine plant tours, the inspectors identified a number of situations where there exists a potential for unanalyzed seismically induced system interactions:

(1) In the Unit 1 Bus F 480V switchgear room, the inspector found a portable fan suspended from vital conduit.

(2) At the intake structure, the inspector found the conduit and pull box for the motor (which had been removed) of screenwash pump 1-2, tied off with rope to various structures in the immediate area, including vital conduit.

(3) The inspector found the protective bus covers for the three Unit 1 vital direct current (DC) distribution buses to be missing most of their securing bolts.

(4) In the Unit 2 component cooling water heat exchanger room the inspector found wooden planks lying unsecured above the pit for valve 2-FCV-603 and adjacent to vital instrumentation lines.

(5) In the Unit 2 Residual Heat Removal (RHR) pump 2-2 room and the Unit 2 turbine driven Auxiliary Feedwater (AFW) pump room the inspector found unsecured and unattended 8 foot step ladders standing next to vital equipment.

(6) In the Units 1 and 2 vital cable spreading rooms, the inspector found unsecured and unattended Instrumentation and Controls (I&C) test instrument carts and a workbench on wheels in close proximity to vital instrumentation cabinets.

All items were brought to the attention of appropriate licensee personnel and were subsequently corrected. The licensee reviewed the potentially significant items for the possibility of a seismically induced system interactions and their impact on safe plant operation following a seismic event.

For Item (1), it was determined that the conduit could have supported the fan during a seismic event. In addition, the conduit supplies one of the two control room Heating, Ventilation and Air Conditioning (HVAC) pressurization fans. These fans are only required following a large radiological release which is not postulated following a seismic event. For item (2), the conduit. labeled as vital, supplied instrumentation for a circulating water pump, which is not a component important to safety. For item (3), it was determined that the protective cover did not provide any structural support to the breakers. In addition, even in a completely unsecured condition, the positioning of the cover is such that during a seismic event it could not have interfered with the operation of the breakers. Items 4, 5 and 6 were considered to be such that they would not impact safety related equipment in a seismic event, however they also indicate a need for additional attention to SISIP.

Administrative Procedure C-10S1, "SISIP Review of Housekeeping Activities," provides three levels of responsibility. The Quality Control Manager is responsible for developing and implementing a program of surveillances. Each supervisor is responsible for assuring potential SISIs are not created by improper housekeeping within the supervisor's control. The Engineering Manager is responsible for required engineering evaluations. The items identified by the inspector indicate an apparent weakness in the second level of responsibility, that of the cognizant supervisor. The licensee discussed a number of steps they are taking to increase worker sensitivity to SISI issues in the March 6, 1987 management meeting and the inspectors have requested that the licensee provide a letter describing the specific actions taken (Inspection Report Nos. 50-275/87-12 and 50-323/87-11).

No violations or deviations were identified.

3. Event Follow-up

a. Unit 1 Technical Specification Required Shutdown and Subsequent Reactor Trip

At 3:05 a.m. on February 22, 1987, Train B of the Unit 1 Solid State Protection System (SSPS) was removed from service for routine surveillance testing and a maintenance activity to replace a bulb socket in the testing circuitry of the SSPS. While troubleshooting the bulb socket, an I&C technician created a small spark when placing the leads of a multimeter across the lamp socket. The Train B 48 vdc power supply breakers tripped, de-energizing the undervoltage coils on the Train B reactor trip breakers (RTB B and bypass breaker A). However, bypass breaker B had been closed when SSPS Train B was removed from service, providing power to the control rod mechanisms and preventing a reactor trip. I&C technicians re-energized the 48 vdc power supply, and operators closed reactor trip breaker B. Operators also heard "noise" from the source range audio rate monitor, and noticed both source range channels had been energized when the 48 vdc power supply breakers tripped. Even though the I&C technicians had re-established 48 vdc power to the SSPS, the earlier de-energizing of the 48 vdc power

power to the SSPS, the earlier de-energizing of the 48 vdc power supply caused a logic circuit card in the SSPS to "lock-up" preventing a master relay from removing power to the source range detectors. Consequently, the source range detectors were energized at 92% power for a period of about 22 minutes until operators placed the source range channels in level trip bypass and removed the source range instrument power fuses to de-energize the detectors. Both source range high flux bistables had actuated when the detectors pegged high, but the trip function had been correctly manually blocked when the P-6 setpoint was reached during the last reactor startup.

I&C personnel continued to evaluate the cause of the SSPS logic lock-up and successfully returned the logic card to a functioning condition. Surveillance testing was performed on Train B of the SSPS, and the train was declared operable at 8:36 p.m. on February 22, 1987. Consequently, power reduction was curtailed, the plant was stabilized, and preparations for power escalation were begun.

Main feedwater (MFW) pump 1-2 was placed in manual control and reduced to minimum speed to improve low load feedwater pump control. Operators selected to run down pump 1-2 since the individual remote-manual station (slave controller) on MFW pump 1-1 had been experiencing persistent intermittent problems pegging at 100% when selected to manual control. High feedwater flow, increases in steam generator level, and higher than expected feedwater pump speed demand prompted the operators to place the MFW pump master remote station in manual and reduce the speed of MFW pump 1-1. Steam generator levels gradually decreased, and level and feedwater flow stabilized in their normal regions. The MFW pump master station was then placed back into "auto" control. Feedwater flow unexpectedly increased again even though steam generator levels were in the normal range. Accordingly, operators returned the master station to manual control, and pump speed was reduced to match feedwater flow with steam flow. Operators then noticed controllers for feedwater regulating valves FCV 520 and FCV 540 (to steam generators 1-2 and 1-4, respectively) were saturated open, manually increased MFW pump 1-1 speed to drive closed the regulating valves, and caused a rapid increase in steam generator 1-1 level. Steam generator 1-1 regulating valve FCV 510 was placed in manual and closed to about 5% demand to reduce MFW flow. Regulating valves FCV 520 and 540 were also placed in manual to slightly reduce MFW flow and prevent further problems with the controllers saturating open. FCV 510 was closed to the 0% demand position to counteract increasing level in steam generator 1-1. Operators then noticed level in steam generator 1-4 was rising rapidly, closed FCV 540, but level continued to swell to the P-14 setpoint, tripping the turbine and the reactor. The turbine trip/reactor trip cannot solely be related to high water level in steam generator 1-4 however, since steam generator 1-1 was at about 65% level at that time and would have initiated a P-14 signal if steam generator 1-4 had not. The resident inspector was in the control room at the time of the trip and observed operators stabilize the plant.

One minor contributor to the P-14 trip was the substitution of the steam generator 1-4 chart recorder (FR 540) drive with a similar drive from the Auct. Tavg/Tref chart recorder (TR 412) during the previous shift. The FR 540 chart on steam generator 1-4 normally records feed flow (green), steam flow (red), and narrow range water level (blue). Water level indication on the recorder was erratic, so operators exchanged this recorder drive with the Tavg/Tref recorder drive (since it was scaled the same and had a correctly functioning unused third pin). The malfunctioning pin was not needed on the Tavg/Tref chart. However, once the drives had been exchanged, steam flow on FR 540 was now indicated in blue, and narrow range level was now indicated in red. The oncoming shift was aware of this change, but during the feedwater transient, the operator may not have fully and clearly appreciated that the upward trending red graph represented increasing steam generator level. While having the knowledge that the pin colors had been reversed, the operator may not have been able to intuitively react to the indicated level change.

Licensee corrective actions associated with the SSPS related events and P-14 trip were observed by the inspector and discussed with licensee management. Having tested the multimeter used in troubleshooting the SSPS light bulb socket, the licensee concluded the spark resulted from the I&C technician shorting together two socket leads with a test probe of the multimeter. The bulb socket was replaced and the SSPS passed required surveillance tests prior to reactor startup. The source range detectors were determined to have been unaffected by having been energized at 92% power. This was evidenced by the detectors tracking together and overlapping the intermediate range detectors correctly, and by the licensee performing a high voltage plateau calibration check on the detector. Westinghouse concurred in the licensee's determination of source range detector operability. Nevertheless, the licensee is investigating the necessity of replacing the source range detectors during the next Unit 1 refueling outage.

In discussions with licensee management regarding the steam generator level control problems, the licensee indicated that calibration of the zero on the current to pneumatic (I/P) converter on the FCV 510 operator was off, allowing the valve to remain slightly open when its controller demanded the valve to be in the closed position. The zero was re-calibrated, and the controller was verified to be functioning correctly. Licensee management also committed to the NRC that prior to startup, 1) the individual remote-manual station (slave controller) on MFWP 1-1 would be replaced, 2) a chart recorder drive with correct pin colors would be installed in the steam generator 1-4 chart location, and 3) General Electric Transient Analysis Recording System (GETARS) would be connected to continuously monitor the pressure difference (delta P) between the feedwater header and steam generator common header, feedwater flow, and the demand signals to the four MFW regulating valves. This would permit data gathering and analysis of any MFW system perturbations during startup.

During actual reactor startup, minor regulating valve oscillations (which did not appreciably affect feedwater flow) were recorded. As steam flow, feed flow, and MFW system/steam header delta P affect MFW regulating valve position, the licensee is continuing to investigate the need for further control system refinements.

The inspector independently determined the chart recorder drive had been replaced and GETARS connected, but the individual remote-manual station (controller) on MFW pump 1-1 had not been replaced prior to startup. Rather, it had been removed, tested, found to be functioning correctly and returned to service. I&C Department personnel indicated the controller was as reliable and functional as any available replacement unit, and that all available controllers at one time or another exhibit the same persistent problem when installed in the MFW pump 1-1 remote manual station location. As the problem was intermittent, the licensee was unable to isolate the cause of the problem, but indicated that numerous checks of the control modules had been performed in the past. The inspector requested the licensee to determine if further evaluation of the intermittent controller problem was warranted.

b. Unit 2 Reactor Trip on Low-Low Steam Generator (S/G) Level

On March 5, 1987 during plant startup, Unit 2 experienced a S/G 2-4 low-low level reactor trip from approximately 4 percent power. The plant exhibited normal response to the trip and was stabilized in Mode 3 utilizing appropriate Emergency Operating Procedures. Prior to the reactor trip, the main turbine was rolling at 550 rpm with the reactor at 2% power. The turbine was ramped up at 100 rpm per minute in order to perform simulated overspeed and low vacuum trip tests in accordance with STP M21A "Main Turbine Functional Tests" once turbine speed reached 1800 rpm. As steam flow to the turbine increased, Tavg dropped and water level in the S/Gs decreased, causing an automatic demand increase in AFW flow. Operators manually increased reactor power to about 4.7% to counteract the drop in Tavg. Once operators realized (by observing reactor power, Tavg, and S/G water levels) that AFW flow would not accommodate the turbine ramp rate, the operators first placed the ramp on hold and then changed the ramp rate to 25 rpm per minute. Reactor power was also reduced to about 4.2%. However, S/G levels continued to decrease and operators again stopped the turbine rollup with the turbine at 1400 rpm. With total AFW flow at its limit, S/G 2-4 was receiving slightly less AFW flow than the other generators, so operators took manual control of the S/G 2-4 supply valve (LCV 113) to increase flow approximately 10 gpm (additional flow was limited in order to prevent further shrink in the S/G). Nevertheless, S/G 2-4 level eventually shrank to the low-low level reactor trip setpoint of 15% narrow range indication.

The licensee's evaluation of this event concluded the cause was operator error, as it was not recognized that steam demand required for a 100 rpm per minute turbine ramp rate was beyond the capacity of the AFW system to replenish S/G level. It is possible to bring the turbine to rated speed using the AFW system, however, this can

only be accomplished at a slower ramp rate. Complicating factors include that the turbine was rolled up on the AFW system instead of the main steam system as is normally done in accordance with Operating Procedures (OP) L-2, "Hot Standby to Minimum Load." As permitted by OP L-2, the Shift Foreman (SFM) changed the normal sequence of steps in the procedure, but implications of these changes were not conveyed to the control operator (CO) in a "tailboard" prior to rolling the turbine. At the time of the event, the SFM was involved in a shift turnover briefing. The SFM had previously communicated to the control operator (CO) that he wanted the plant on line by a certain time, but did not mean to suggest that the turbine ramp up should begin. However, the CO interpreted the communication such that turbine ramp up was initiated. No formal SFM approval is required to proceed with power ascension. Other experienced operators were also participating in the briefing, which reduced the number of available operators directly involved with the evolution.

Licensee corrective actions included issuing an operations incident report to be reviewed with all shift crews addressing 1) operations practice of not conducting major plant evolutions during shift briefings and 2) the need for complete "tailboarding" of changes in normal operating practices. Via cover letter to this report, the licensee is requested to provide written response to the NRC describing any further appropriate corrective actions required to prevent reoccurrence of miscommunications of this nature.

No violations or deviations were identified.

4. Open Item Follow-up

a. Auxiliary Saltwater Valve FCV-602 (Open Item 50-275/87-04-02, Closed)

Inspection Report No. 50-275/87-04 described corrective maintenance activities performed on Auxiliary Saltwater (ASW) valve 1-FCV-602 which had failed to stroke completely during routine surveillance activities on the January 13, 1987 graveyard shift. ASW train 1-1 was declared inoperable and mechanical maintenance initiated work. On the graveyard shift maintenance greased the lubrication fittings and cycled the valve. On day shift, a manway on component cooling water heat exchanger (CCW Hx) 1-1 was opened in the presence of Chemistry and Radiation Protection (CARP) technicians and made available to maintenance. Opening the CCW Hx allowed access to the insides of 1-FCV-602. Maintenance discovered some marine growth in the internals of the valve and removed it, however 1-FCV-602 did not completely stroke after the removal. The maintenance mechanics proceeded to lubricate the actuator cylinders with a light mineral oil and repeatedly stroked the valve with limited success. Accordingly, maintenance greased the pivot area of the actuator and the valve-actuator interface bushing and inspected the actuator cylinders. These measures allowed the valve to operate freely, and a successful stroke time test was performed the following day.

Upon review of the Action Request initiated for 1-FCV-602, quality control issued a quality evaluation for this work. A quality evaluation provides the means for which root cause and actions to prevent recurrence are established for conditions adverse to quality. In following up the open item related to 1-FCV-602, the inspector discovered that the root cause identified in the subject quality evaluation, which had been completed, was "marine residue on stem." The quality evaluation also determined that no further corrective actions needed to be taken. The inspector determined the quality evaluation was inaccurate since marine growth was a minor contributor to the valve not fully stroking compared to need for lubrication. In addition, effective corrective action should have included scheduling the valve for periodic lubrication.

These concerns were identified to licensee management, who concluded that the subject quality evaluation was insufficient, and it was re-opened for further review. The re-opened quality evaluation concluded that the contributing causes were "1) Excessive friction due to insufficient lubrication, 2) Environmental conditions cause buildup on corrosion and marine products that contribute to reduce free valve movement." As corrective action, the quality evaluation listed three items: 1) To place the valve on a 30 day valve stroking schedule, as opposed to the current 90 day schedule. At each interval the valve will be stroked four times instead of once. 2) To place the valve on a six month inspection and lubrication schedule. 3) To request that two lubrication points be added to the valve disc shaft bushing interface. The inspector finds the root cause to be accurate and the corrective actions to be acceptable.

The only other valves with this particular valve actuator used in safety related applications are the containment ventilation supply and exhaust valves. These valves however are stroked and leak tested each time the containment is purged, and are stroke timed every cold shutdown. Maintenance management has concluded that the problems experienced with 1-FCV-602 are not applicable to the containment ventilation valves with similar operators. All other safety related pneumatic actuators are diaphragm actuators and therefore do not need lubrication. The licensee, however, is planning a diaphragm replacement program since the diaphragms wear out with heat and age. The licensee concluded that trending stroke test times is adequate to identify any further maintenance requirements for these valves. Open Item 50-275/87-04-02 is closed.

The inspector determined that the cause of the errant quality evaluation was a break down of the communications chain from the maintenance mechanics to the maintenance engineer performing the evaluation. Since an evaluator can not be physically present at all jobs for which he is to perform an evaluation, this communications chain is vital and should not be subject the to information distortion inherent in second hand communications.

The licensee is currently investigating the communications chain in an effort to identify areas of weakness and what training or

procedural revisions are needed to establish better communications. This is another example of problems arising from second hand information. The other examples were the maintenance effort following the simultaneous opening of both containment personnel airlock doors (Inspection Report 40-275/86-29) and the use of the control rods in the automatic mode while that mode was in a test condition (Inspection Report 50-275/87-04). The inspectors discussed these examples with licensee management at the exit interview on March 20, 1987 and informed the licensee of the request for a written response to address this issue.

b. Review of Surveillance Test Procedure (STP Identified Five Items of Concern) Open Item No. 50-275/85-21-04

Inspection Report 50-275/86-30 of November 18, 1986 identified that only concern (d) of this follow-up item had been resolved by the licensee at the time of that inspection, and that the NRC's Office of Nuclear Reactor Regulation (NRR) was reviewing item (e).

Item (e) stated:

> "The leakage tests for reactor coolant system pressure isolation valves did not determine actual leakage rates and thus leakage rates were not being trended. As 14 of these 18 valves are at least 6 inches in diameter, Subsection IWV-3427 requires trending of leakage rates to establish the need for increased testing frequency or corrective action. These valves are only being tested per Technical Specifications to determine that leakage is less than one gallon per minute. This question will be referred to NRR for resolution."

NRR has provided an opinion on item (e) which addresses pressure isolation valves (PIV).

> "Essentially, Paragraph IWV-3427 (b) requires that leak rates which increase from one test to a later test of any particular valve beyond a specified rate, be either tested more frequently or repaired, depending on the leakage rate. Most of the PIV leak test requirements are in the technical specifications, but paragraph IWV-3427 is not specifically noted.
>
> "The licensee can fulfill all of his technical specification commitments without measuring leak rate trends in accordance with the ASME Code paragraph IWV-3427. However, the licensee's IST program requires that all leak rate testing be performed in accordance with the ASME Code Section XI including paragraph IWV-3427 (see section 5.2.8.1 of the Diablo Canyon SER Supplement 32, NUREG 0675). In order to comply with his commitments regarding performance of the IST program, the licensee must comply with the requirements of IWV-3427 when leak rates are measured for valves categorized A or A/C, as the PIV's are.

"There is no conflict between the technical specifications and the IST program on this issue. The IST program requires that the licensee fulfill additional record keeping and measurement requirements beyond those required in the technical specifications. Accordingly, the licensee must comply with both the technical specification and the IST program. In this case, the IST program requires compliance with the ASME Code paragraph IWV-3427 even though the Technical Specifications do not."

The information above was discussed with the licensee at the exit meeting. The licensee stated that appropriate action would be taken.

c. Notice of Violation on Control of Snubber Removal with Respect to System Operability (Open Item 50-275/86-29-03, closed)

On November 14, 1986 NRC Region V issued a Notice of Violation for a Severity Level IV violation involving a lack of Technical Specification equipment operability review with respect to snubber removal for testing.

The inspector has reviewed the licensee's response letter DCL-86-356 and finds the corrective actions to have been implemented. This was accomplished by review of revised procedure AP C-6S4, "Control of Equipment Required by the Plant Technical Specifications," and discussions with the Maintenance engineer responsible for the Unit 2 snubber testing program. Thereby, Open Item 86-29-03 is closed.

No violations or deviations were identified.

5. Maintenance

The inspectors observed portions of, and reviewed records on, a selected maintenance activity to assure compliance with approved procedures, technical specifications, and appropriate industry codes and standards. Furthermore, the inspectors verified the maintenance activity was performed by qualified personnel, in accordance with fire protection and housekeeping controls, and replacement parts were appropriately certified.

a. Unit 1 - SSPS Logic Lock-up

As described in Section 3a, Train B of the SSPS "locked-up" when a technician unintentionally shorted the leads of a SSPS test lamp socket. The inspector observed technicians performing corrective maintenance on the SSPS logic circuity. Required administrative approvals had been obtained prior to performing the work, and the work was performed in accordance with a work order. Prior to returning to SSPS to service, the appropriate portion of a surveillance test procedure was performed.

No violations or deviations were identified.

6. Surveillance

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

a. Unit 2 Incore Flux Mapping and Incore/Excore Calibration

The inspector witnessed portions of STP R-13 "Nuclear Power Range Incore/Excore Calibration." The test determines the relationship between incore and excore measured axial offset. The data obtained provides the input for the calibration of the delta flux indication and the delta flux penalty input to the overtemperature delta temperature reactor trip setpoint. STP R-13 required the performance of a number of full core and quarter core flux maps which are performed according to STP R-3A, "Use of Flux Mapping Equipment." During the performance of the initial full core flux map detector E failed to travel through two of its twelve paths. Although of only 75% of the paths are need to be used in accordance with TS 3.3.3.2 for a full core flux map, the two paths were both needed for the quarter core flux maps. After the full core flux map was performed, the engineer performing the test suspected that the clutch mechanism for detector E was slipping due to minor blockage of the two guide tubes. Accordingly, he sent detector D, by way of its "emergency" path, through the two paths. The engineer then successfully sent detector E through the two paths and was able to use the paths in the quarter core flux mapping. STP R-3A provides for this operation, and the inspector found these actions resourceful and acceptable. The engineer has initiated an Action Request noting the difficulties experienced during the first full core flux mapping.

The inspector noted that applicable Technical Specifications were complied with and that the engineer performing the surveillance appeared knowledgeable and familiar with the equipment and procedure.

b. SSPS Train B Slave Relay K614B

The inspector witnessed operators perform portions of STP M-16L "Operation of Slave Relays K614A and K614B (Phase A Containment Isolation)" on Unit 1 Train B of the SSPS. The purpose of the test was to verify certain containment isolation valves moved from the open to the closed position upon slave relay actuation. Required administrative approvals were verified to have been received, prior to performing the task. This test was required by TS LCO 3.3.2 prior to entering Mode 4, since maintenance activities had previously been performed on Train B of the SSPS (as described in section 5a. of this report). Step B. "Pretest Alignment" of the STP specifies that the valves to be tested should be verified to be open, or be opened for the test, if closed. During the test, the inspector identified that the operator had failed to document the pretest valve alignment positions on the test data sheet. In

discussions with the operator, the operator indicated he had verified the pretest valve positions but failed to enter the information on the data sheet. As the test data had not been reviewed by the Shift Technical Advisor (STA) or shift foreman, this obvious omission may have been identified during the review/acceptance process. FCV-257 "Reactor Coolant to Gas Analyzer isolation" was not subjected to this test, as required by the STP, since the valve was not operable from the closed position prior to the test. The valve was not operable from the control room since the valve was interlocked with the gas analyzer which was out of service.

No violations or deviations were identified.

7. Reinstallation of Unit 2 Low Density Spent Fuel Racks

In preparation of reuse of the low density spent fuel racks for Unit 1, the licensee performed a "state of the art" seismic analysis and found the original bolted configuration resulted in some bolts possibly being overstressed. In the original design, the racks were bolted to the spent fuel pool embedments. The licensee implemented a design change which removed the racks bolted feet, (from the racks), welded a plate to the corners of the racks, and welded those plates to the spent fuel pool embedment plates. The inspector examined the embedment to plate and plate to rack welds for 12 of 32 locations. The inspector found adequate weld size in each location, and in general the welds were conservatively large. To perform the seismic analysis, the licensee had the Onsite Project Engineering Group (OPEG) perform "as built" measurements of the rack gusset welds. The inspector examined 40 of these fillet welds and compared length and size to the licensee's as-built measurements. In general, the as built measurements appeared to be conservative. However, the inspector found two adjacent welds on one gusset to be 7 inches in length as opposed to the as built measurement of 8 inches. This was brought to the attention of the corporate engineering group. The licensee's response was that the welds in question were more than adequate for service. The seismic loading calculation showed that the gusset weld could withstand a load of greater than three times that required. It is speculated that the one inch discrepancy resulted from the measurer reading his scale in error.

The licensee further stated that engineering personnel had further doublechecked all welds which had lesser capacity margins. The welds identified by the inspector had not been double checked because their capacity far exceeded any possible loading.

No violations or deviations were identified.

8. Licensee Event Report Follow-up

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

Unit 1: 86-42, 86-12, 86-18, 86-20, 87-03

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

No violations or deviations were identified.

9. Exit

On March 20, 1987 an exit meeting was conducted with the licensee's representatives identified in paragraph 1. The inspectors summarized the scope and findings of the inspection as described in this report.