U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/90-05 and 50-323/90-05

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: January 28, through March 10, 1990

Inspectors: P. P. Narbut, Senior Resident Inspector

K. E. Johnston, Resident Inspector

Approved by: M. M. Mendonca 4/4/90
M. M. Mendonca, Chief, Reactor Projects Section I Date Signed

Summary:

Inspection from January 28 through March 10, 1990 (Report Nos. 50-275/90-05 and 50-323/90-05)

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 30702, 30703, 37700, 37702, 40500, 42700, 61726, 62702, 62703, 71707, 92700, 92701, 92703, 92720, and 93702 were used as guidance during this inspection.

Safety Issues Management System (SIMS) Items: None.

Results:

General Conclusions on Strength and Weaknesses

Additional Equipment Lineup Problems: Twice during the inspection period operators made significant equipment lineup errors which affected the operation of safety related equipment (paragraphs 4e and 4h). The errors indicated that operations management had not yet been fully successful in communicating their expectations regarding the equipment lineup process to operations personnel.

Design Work Concerns:

In this inspection period there were two concerns on design work. Paragraph 3c describes a situation where security personnel designing modifications to the intake area security barriers based design assumptions on inaccurate information regarding the normal configuration of the auxiliary saltwater system. Although this did not result in a violation of the licensee's security plan, it indicated a weakness in the communications between security, plant engineering and operations with respect to security design. Paragraph 4j discusses the last minute postponement of the removal of the Unit 2 Boron Injection Tank due to design problems discovered by both design Engineering and Quality Assurance.

Failure to Recognize and Elevate Problems

In September 1989, general construction personnel, excavating for a design modification, unearthed and gouged safety related auxiliary saltwater piping without recognizing the significance of the act and did not notify plant management or initiate the required problem reporting process which resulted in a violation (paragraph 5a).

Timely Operator Action

At the start of the Unit 2 refueling outage, Operators on Unit 2 recognized and took corrective actions to address a rather obscure potential Residual Heat Removal system suction valve isolation problem (paragraph 4).

Good Problem Identification

Although also mentioned as a design work concern, Engineering and QA identified problems with the Boron Injection Tank removal modification and took conservative action to postpone the design change.

Significant Safety Matters: None.

Summary of Violations and Deviations: One violation was identified concerning failure to take corrective action - paragraph 5.a.

Open Items Summary: 18 open item were closed in this report. One was opened.

DETAILS

1. Persons Contacted

J. D. Townsend, Vice President, Diablo Canyon Operations and Plant Manager
D. B. Miklush, Assistant Plant Manager, Operations Services
*M. J. Angus, Assistant Plant Manager, Technical Services
B. W. Giffin, Assistant Plant Manager, Maintenance Services
*W. G. Crockett, Assistant Plant Manager, Support Services
*W. D. Barkhuff, Quality Control Manager
*T. A. Bennett, Mechanical Maintenance Manager
*D. A. Taggert, Director Quality Support
*T. L. Grebel, Regulatory Compliance Supervisor
H. J. Phillips, Electrical Maintenance Manager
D. P. Brooks, Acting Work Planning Manager
*R. C. Washington, Acting Instrumentation and Controls Manager
*J. A. Shoulders, Onsite Project Engineering Group Manager
M. G. Burgess, System Engineering Manager
*S. R. Fridley, Operations Manager
*R. Gray, Radiation Protection Manager
E. C. Connell, Assistant Project Engineer

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

*Denotes those attending the exit interview on March 23, 1990.

Also attending the exit meeting was Marvin M. Mendonca, NRC Section Chief.

2. Operational Status of Diablo Canyon Units 1 and 2

At the beginning of the report period, both Units 1 and 2 were at full power. On February 20, 1990, operators manually tripped Unit 1 following the closure of the feedwater regulating valves which was apparently precipitated by surveillance activities in the solid state protection system cabinets (see Section 4.b). On February 22, 1990, the licensee gagged one of three Unit 2 pressurizer safety valves, after receiving an emergency Technical Specification change, when its leakage increased (see Section 4.c). On March 4, 1990, Unit 2 shut down for its third refueling outage. At the end of the report period, Unit 1 was at full power and Unit 2 had just entered Mode 6; core alterations.

On February 2, 1990, a team inspection, which reviewed the corrective actions and oversite programs, conducted an exit meeting (see Inspection Report 50-275/90-01). On February 12, 1990, after a temporary injunction was lifted, random drug screening began for applicable union members.

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

(d) Interiors of electrical and control panels.

(e) Plant housekeeping and cleanliness.

(f) Engineered safety feature equipment alignment and conditions.

(g) 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. Radiological Protection

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, including the Diablo Canyon project inspector, observed the activities at the access point for the radiological controls areas (RCA) on February 21, 1990, prior to the start of the Unit 2 refueling outage. The inspectors noted that personnel leaving the area were not exercising good radiological practices, in that opportunities for potentially contaminated personnel to contaminate clean personnel were being created.

The licensee uses personnel contamination monitors (PCMs) to monitor personnel exiting the RCA. The PCMs are sensitive and detect naturally occurring radioactive radon and its daughter products.

The licensee has had the long-standing and common problem of radon adhering to clothing by electrostatic charge. The extent to which radon is present in the auxiliary and fuel handling buildings is in large part dependent on atmospheric conditions.

The inspectors observed a situation where, on a relatively high concentration radon day, approaching lunch time, with one of the three PCMs out of service, approximately half of the people attempting to exit the RCA were alarming the PCMs and a substantial line (10-15 people) had developed. The radiation protection (RP) technician responsible for monitoring personnel and equipment leaving the RCA appeared to be overwhelmed with responding to the alarms and performing other tasks such as frisking equipment. As a result, personnel were performing self analysis of their alarms and loitering in line to allow radon to decay. This presented the opportunity for personnel who had alarmed the PCMs, and who might have been genuinely contaminated, to potentially contaminate uncontaminated personnel.

The inspectors presented these findings to the RP manager. The RP manager stated that radon was not a health risk in the levels existing in the auxiliary and fuel handling buildings but the number of resultant alarms at the RCA exit area tended to reduce employee sensitivity to alarms. He noted that PG&E had plans to reduce the radon levels, possibly including the capping of a well used to evaluate water conditions at the containment base. Also, the licensee is considering reducing the frisker's sensitivity to radon. However, the RP manager agreed that RP technicians need to control RCA exits to ensure all alarms are adequately assessed. The inspectors will observe the licensee's actions regarding this matter in future inspections.

c. Physical Security (71707)

Security activities were observed for conformance with regulatory requirements, implementation of the site security plan, and administrative procedures.

On January 30, 1990, the inspector examined the seawater intake area including recently completed modifications to the security boundaries. The inspector identified two apparent examples of vital auxiliary saltwater system (ASWS) equipment located outside a vital area boundary. The specifics are not discussed here because they are security safeguards information.

These findings were discussed with the security manager who initiated a review of the findings and an evaluation of the intake security modifications. Subsequently, a third apparent example of vital ASWS equipment located outside a vital area boundary was identified by the licensee.

The licensee's analysis of the potential consequences of the three findings assumed the worst postulated challenge in accordance with the security plan and the effects on ASWS operation. In all cases it was found that existing control room annunciation and proceduralized response would successfully mitigate event consequences.

Although the potential consequences of the findings were not significant when a security analysis was performed, they pointed to a weakness in the security design process. In the two examples identified by the inspector, the design decisions to not include the equipment in a vital area were based on faulted assumptions of normal system operation.

No changes to the security boundaries resulted from the licensee's evaluations. However the uncertainty which existed indicated a weakness in the communication between security designers, who have in-depth knowledge of the security plan but not of system operation, and operations and engineering personnel, who have in-depth knowledge of system operation and design but not of the security plan.

The inspector discussed these concerns with the security manager who agreed that the interface between security and operations required improvement and committed to do a thorough evaluation of the cause and pursue appropriate corrective actions. The inspector will follow the licensee's actions in the course of routine inspection.

No violations or deviations were identified.

4. Onsite Event Follow-up (93702)

a. Minor Earthquake Near Diablo Canyon

On February 6, 1990, an earthquake of approximate magnitude 3.6 to 3.9 occurred 30 to 60 miles south-southwest of the plant. Although most plant personnel did not feel the earthquake, the earthquake triggered sensitive monitoring devices. A plant individual did feel physical motion and notified the control room. Consequently an Unusual Event was declared and plant walkdowns were initiated in accordance with procedures. No damage was identified by the walkdowns. Ground acceleration was later measured to be 0.002 g.

b. Unit 1 Manual Reactor Trip Following Feedwater Regulating Valve Closure

At 5:30 a.m. PST on February 20, 1990, Unit 1 reactor operators manually tripped the reactor from 100% power in response to the loss of both main feedwater pumps. All safety systems responded normally. The licensee made a 4 hour non-emergency report to the NRC and documented the event in a written report in accordance with 10 CFR 50.73.

The licensee's LER (Licensee Event Report) 1-90-02 provides an accurate description of the event and detailed explanations of the licensee efforts to identify the cause of the event. Therefore those facts will not be repeated here.

The resident inspectors observed licensee management actions in the event analysis and attended the plant staff review committee meeting which approved restart of the unit. Licensee investigative actions were observed to be well planned and conservative. LER 1-90-02 is considered closed.

c. Unit 2 Leaking Pressurizer Safety Valve Gagged

On February 21, 1990, the licensee installed a gagging device on one of three safety valves on the Unit 2 pressurizer. The safety valve (8010B) had been observed to leak on February 20. Operators had observed elevated pressurizer tail pipe temperature, spikes in the pressurizer relief tank (PRT) pressure, increased PRT level, and acoustic monitor alarms on Unit 2. These were the same leakage characteristics that were observed on Unit 2 safety valve 8010A in March 1989 which ultimately resulted in a plant shutdown for repair.

Prior to these events, in anticipation of such an occurrence, on January 25, 1990, the licensee submitted a license amendment request to allow continued operation with one inoperable and gagged pressurizer safety valve. On February 20, 1990 in response to the valves condition, the licensee requested an emergency Technical Specification (TS) change for a one time exemption to allow continued operation with one inoperable, gagged pressurizer safety valve. In their analysis, the licensee considered the possible consequences on affected design basis accidents and concluded that over-pressure protection limits of the accident analysis could be met with two of three safety valves operable. For conservatism, the licensee included in their revised TS a requirement to have one operable and available pressurizer power operated relief valve. On February 21, the NRC approved the emergency TS amendment and the safety valve gag was installed.

On February 26, operators noted a partial return of the symptoms described in the first paragraph. Maintenance personnel inspecting the valve observed that the gag had loosened. The licensee consequently obtained a torque value for the gag from the safety valve manufacturer and tightened the gagging device.

Following the shutdown for the Unit 2 refueling outage, the inspector noted that the gag was again loose. This was discussed with the maintenance manager who discussed plans to have a gag designed with a locking mechanism for any future use.

d. Movement of High Radiation Material Causes Control Room Ventilation System (CRVS) Radiation Detector Actuation

On February 22, 1990, the Unit 1 control room ventilation system shifted from normal mode to pressurization mode when radiation monitor 1-RE-25 actuated. 1-RE-25, the CRVS radiation monitor, which actuates at approximately 1.6 mr/hr, actuated when radioactive material was transferred from the Unit 1 spent fuel pool to a shipping cask.

The radiation protection review prior to movement of the radioactive material identified the fuel handling building radiation monitors 1-RE-58 and 1-RE-59 as potentially actuating, but did not identify the control room radiation monitors, which are located outside the fuel handling building but are separated only by sheet metal walls.

The licensee made a four hour non-emergency report after identifying the event as an unanticipated engineered safety features actuation. The licensee will submit a licensee event report (LER). The inspector will review the LER in a future inspection to evaluate the licensee's actions.

e. Valve Line Up Error Isolates Boric Acid Transfer Pump 1-1 Suction Supply

On February 26, 1990, boric acid transfer pump 1-1 was found running in low speed with its suction valve closed. It was subsequently determined that the valve had been inadvertently isolated following a boric acid batching operation approximately five to six hours earlier. At the time of this event, the other boric acid transfer pump (1-2) was out of service for seal repair but an alternate boration flowpath was available from the refueling water storage tank through the charging pumps.

The boric acid transfer pumps are required in Technical Specification (TS) 3.1.2.2 to support a boration flow path from the boric acid tanks to the reactor coolant system (RCS). The TS allows the boric acid tanks flow path to be out of service for up to 72 hours. The boric acid transfer pumps are also required to recirculate 12% weight boric acid through the boron injection tank (BIT). Surveillance requirements are that this flow be verified every seven days. In summary, while the loss of both boric acid transfer pumps resulted in a loss of BIT recirculation flow and required entry into a 72 hour action statement, it had limited safety consequences. Additionally, although it had operated for almost six hours with its suction valve closed, boric acid transfer pump 1-1 was tested on February 27 and found to be undamaged.

The suction valve was closed due to operator error. The licensee's analysis of the event found the following contributing factors which ultimately resulted in the closing of the pump suction valve:

- The boric acid batching job was being performed without properly using the available procedure. The auxiliary operator

(AO) was using the procedure located at the auxiliary control board and did not have a copy for use in the field. After reviewing the procedure at the auxiliary control board, the AO made a note to himself of the appropriate valve to close, he left the note in his pocket when he dressed to enter the surface contaminated area to manipulate the valve. The procedure was not followed verbatim. The AO elected not to perform certain valve lineups to isolate normal pump suction while draining the batch tank.

o The pump suction valve was probably not properly sealed. The valve seal was subsequently found broken but might have been broken by the A.O.

The licensee's analysis recognized other minor contributors, such as poor lighting and the absence of a valve identification label, but the root cause was attributed to a lack of formality in performing the job.

In review of the event, operations management determined that the valve lineup program, requirements were adequate. However, licensee management determined that management's expectations had not been successfully conveyed to the operators performing the lineups.

As corrective action, in addition to the usual event summary discussed during turnover with all operation crews, the operations manager issued a memorandum to all operations personnel which restated the elements of the valve lineup program and reemphasized the necessity to follow the program. The memorandum required that all operators read the memorandum, sign that it had been understood, and return a signed acknowledgement to the operations manager. The licensee stated that this approach was taken to successfully communicate the importance of valve lineups with all personnel performing lineups. The licensee's corrective actions seem appropriate.

The inspectors will continue to evaluate the adequacy of the licensee's equipment lineup programs.

f. <u>RHR Suction Isolation Valve Operability</u>

On March 6, 1990, through discussion with operators in Unit 2, the inspector became aware of a jumper which had been prepared which would allow the Residual Heat Removal suction valves to be opened if for some reason they were inadvertently closed. The operators discovery of this rather obscure fact that due to the combination of clearances for outage work the suction valves could be powered closed but not powered open again demonstrated their indepth knowledge and insight into plant operations. This unlikely circumstance was due to the work clearance on the solid state protection system (SSPS) which was consequently depowered. Since the SSPS interlocks opening of the RHR suction valves under certain conditions, the operators were precluded from opening the valves if

they had inadvertently shut. The operators had prepared jumpers and marked up electrical schematics to open the valves if the need arose.

The inspector discussed the situation with the assistant plant manager (APM) for maintenance and suggested that a more appropriate solution would have been to revise the work procedure for the SSPS to add the installation of the jumper as a procedural requirement to de-power SSPS. The APM agreed and stated that the procedure would be so revised for future outages. An action request was issued to track this action.

g. Unit 2 Fuel Handling Building Ventilation Mode Shift Due to Inadequate Procedure

On March 7, 1990, while performing a design change on the Unit 2 spent fuel pool radiation monitor, 2 RM-58, the fuel handling building ventilation system (FHBVS) transferred from normal to iodine removal mode. The transfer occurred when the "high alarm" relay associated with RM-58 actuated. It actuated when technicians, following steps in the design change package, lifted a lead which supplied power to the relay. The relay, which actuated on loss of power, initiated the FHBVS mode transfer to iodine removal.

The licensee made a four hour non-emergency report since the FHBVS transfer was classified as an unanticipated engineered safety feature actuation. A nonconformance report (NCR DC2-90-TI-N010) was initiated. The NCR stated that a licensee event report (LER) was required. The inspector will review the licensee's actions during review of the LER.

h. Isolation of Unit 1 Feedwater Pressure Transmitters

On March 9, 1990, Unit 1 was at 100% power, and Unit 2 was shut down and in a refueling outage. A senior control operator (SCO) performing valve lineups for a work clearance on Unit 2, erroneously isolated three Unit 1 steam generator pressure transmitters. One of the isolated pressure transmitter outputs drifted from approximately 800 psig to 540 psig. This resulted in alarms in the Unit 1 control room. The Unit 1 control room operator asked the Unit 2 operator if they had an evolution in process which would produce such an indication and the possibility of the isolation of steam generator pressure transmitters on the wrong unit was quickly suspected.

An auxiliary operator (AO) was dispatched to intercept the SCO. The Unit 1 transmitters were then valved back in, seven minutes after they had been isolated. Two of the three transmitters had not begun to drift low. If one other transmitter had drifted low, a reactor trip and safety injection could have been experienced.

The isolation of all three steam generator pressure transmitters on one steam generator is not allowed by the Technical Specifications. The licensee made the appropriate 4 hours non-emergency report regarding the inadvertent entry into technical specification 3.0.3.

Although this was another example of valve lineup problems, the inspector was encouraged with the self critical tone in the review performed by operations management and the individual involved. The inspectors will review the event following receipt of the licensee event report.

j. Unit 2 Boron Injection Tank (BIT) Removal Postponed

One of the planned licensee modifications for the Unit 2 refueling outage was the removal of the boron injection tank BIT. Shortly following the commencement of the Unit 2 outage, the licensee decided not to proceed with the BIT removal. Just prior to the outage, the license amendment authorizing removal of the BIT had been issued by the NRC. At the close of the report period the licensee was pursuing a countermanding license revision to postpone the BIT removal.

The decision to postpone the BIT removal was primarily due to questions raised by the engineering organization and a Quality Assurance (QA) audit regarding the adequacy of the design change. The identified problem area concerned the identification of additional components whose environmental qualifications might not be adequate for the slightly harsher post accident environments that would be experienced with the boron injection provided by the BIT. The inspectors will follow the QA review and subsequent licensee actions during routine activities.

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. Auxiliary Saltwater System Piping Gouged During Excavation

During a review of modifications to the seawater intake area the inspector discovered that on September 21, 1989, during excavation for power and telecommunication lines, a buried portion of safety related auxiliary saltwater piping was struck and gouged by a backhoe bucket. This event was documented in an "action evaluation" or AE which was a portion of a general action request for installation of the non-safety telephone and power lines. The response to the problem included non destructive examination of the pipe for wall thickness and recommendations by the onsite project engineering group (OPEG) for the recoating and reburial of the pipe. However, because of the "non-safety related" status of the original action request, root cause mechanisms were not put in place to determine why the pipe was inadvertently uncovered in the first place. Secondly, neither management nor operations personnel were notified to address operability concerns of the gouged pipe.

Administrative Procedure C-12, "Identification and Resolution of Problems and Nonconformances," establishes guidelines for the initiation of Action Request (ARs). Action evaluations (AEs) are associated with individual ARs and are used to request assistance in the resolution of the AR. However, AP C-12 does not allow AEs to be used to document new problems. The procedure requires a new AR to be created for a new problem so that the problem receives appropriate review from QC and plant supervision. Since the existing non-safety related AR, for the installation of utilities to the intake, was used to document the safety related ASW pipe damage, appropriate reviews were not performed.

The inspector brought this finding to the attention of the system engineer, who was unaware of the event and initiated an appropriate AR. The inspector also discussed the event with plant and QC management. A non-conformance report was subsequently written. It was determined, at that time, that based on the non-destructive examination and burial instructions contained in the AE, the ASW piping was operable.

Four issues were focused on in nonconformance report; the administrative aspects as to why a new AR was not generated, the technical aspects of the ASW pipe operability, the lack of security measures while the piping was exposed, and the work control aspects which allowed inadvertent excavation of the ASW pipe. The nonconformance report review determined that the General Construction (GC) excavation permit did not identify the location of ASW pipe. Although drawings indicated that the ASW pipe was five feet underground, GC uncovered the pipe at 18 inches.

With respect to the administrative aspects, the NRC maintenance team of July 1988 (Inspection Report 50-275/88-15) issued a Notice of Violation for failure to implement AP C-12 and initiate an AR for a new problem. Although actions were taken to clarify AP C-12 and training was conducted for all required to implement the procedure, the corrective actions were apparently not successful in this case. The failure to establish an appropriate AR in a timely manner is an apparent violation (50-275/90-05-01).

The roots of this event appear similar to the Notice of Violation issued in Inspection Report 50-275/89-34, where GC personnel erected scaffolding over the Unit 2 vital batteries without obtaining the required engineering review. These events seem to indicate a lack of sensitivity toward operating units on the part of GC personnel.

Additionally plant management was slow to react to this problem. The problem was brought to the attention of plant management on March 1, 1990 and security issues specifically discussed. It was not until March 22 that the security department was notified to perform an evaluation for compensatory measures.

The licensee should address in their response to the Notice of Violation; the issues of ASW security and operability while the line was excavated, the adequacy of work control, the adequacy of repairs

performed, actions to increase the sensitivity of construction personnel and any improvements planned in timely response to identified problems.

b. Check Valve Inspection

The inspectors examined and were satisfied with the licensee actions pursuant to the discovery of minor check valve internal interferences (rubbing). During planned inspection of check valves in Unit 2 during the refueling outage the licensee examined valve SI-2-8818B which was a check valve in the emergency core cooling system. The valve and other similar Velan check valves had their internals replaced in the last refueling outage due to a disk rotation and cocking problem. During the current outage the licensee sampled one valve for freedom of motion and noted slight rubbing of the end of the hinge arm against the valve body. The rubbing resulted in a burnished area estimated to be several mils deep. Check valve movement was not significantly hampered according to engineering personnel. Three other similar valves were then disassembled and no additional rubbing was found.

The licensee planned to increase the existing chamfer on the hinge arm ends to eliminate the interference in accordance with vendor instructions. This problem is not considered to be a generic issue because of the minor amount of rubbing. Significant rubbing would have been observed at original assembly.

c. Poor Cleanliness Controls for Temporary Systems

On March 8, 1990 the licensee experienced difficulty and delay in attempting to drain down the reactor vessel for head removal. The temporary system, the reactor vessel refueling level indicating system, RVRLIS was discovered to have a blocked line which precluded venting the reactor vessel head freely.

Subsequent disassembly showed that a tape cleanliness barrier was left installed on a subassembly. The cleanliness barrier (tape) was not removed when the subassembly was installed in the system and became a blockage.

The licensee documented the problem on a quality evaluation to ensure a root cause is determined. There were no safety implications directly applicable from this event. The licensee is very interested in successfully preventing recurrences due to the cost of schedule delays.

d. Modification Work Observed

The inspector observed portions of the Unit 2 modification work in progress on the following modifications:

- installation of digital feedwater control system
- installation of a revised seismic trip

- modification to the AMSAC (accident mitigation system actuation circuitry) system annunciation
- replacement of the plant process computer P-250
- Gammametrics cable replacement due to a 10 CFR Part 21 report
- Rosemount pressure transmitter replacement due to an NRC bulletin

The inspector also observed solid state protection system work on suspect electrical connections which had to be checked for tightness in accordance with a vendor technical bulletin (Westinghouse technical bulletin 89-06).

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.

a. Daily Heat Balance

The inspector reviewed the performance of a daily heat balance on Unit 2 prior to the refueling outage. The heat balance was performed in accordance with surveillance test procedure STP R-2B without the use of the plant process computer which had been taken out of service for replacement.

The inspector reviewed the data and the procedure and found the licensee's actions acceptable.

No violations or deviations were identified.

7. Licensee Event Report Follow-up (92700)

a. Status of LERs

The LERs identified below were closed out after review and follow-up inspections were performed by the inspectors to verify licensee corrective actions:

Unit 1: 88-29 (Revision 1), 88-30 (Revision 1), 88-18, 88-34, 89-07, 89-08, 89-09, 89-10, 89-11, 89-17

Unit 2: 88-16 (Revision 1), 89-06, 89-08, 89-09, 89-11

No violations or deviations were identified.

8. Open Item Follow-up (92703, 92702)

a. (Closed) Unit 1 Enforcement Items 50/275/89-23-01, 02, and 03

The inspector reviewed the licensee's January 2, 1990, response to three violations contained in Inspection Report 50-275/89-23 (dated December 1, 1990). The cause and corrective actions described for the violations concerning the application of the Quality Assurance (QA) program to boric acid heat tracing (50-275/89-23-03) and the control of the hydrogen purge containment isolation valves (50-275/89-23-02) were found to be acceptable. The items are considered closed.

With respect to the overtime violation, the inspector reviewed the January 2, 1990, letter, LER 50-275/89-17, and a February 21, 1990, supplemental response provided in response to an NRC information request. The February 21, 1990, response clarified the root cause to include a "...programmatic breakdown and a lack of procedural guidance including plant management oversite." The letter also discussed in greater detail the scope of overtime violations and to whom the licensee will apply the overtime restrictions in the future. Additionally, the licensee committed to have Quality Control monitor the effectiveness of corrective action implementation during the Unit 2 refueling outage. The inspector found these actions acceptable (Enforcement Item 50-275/89-23-01, and Licensee Event Report 50-275/89-17, closed).

10. Exit (30703)

On March 23, 1990, 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.