U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report Nos: 50-275/91-37 and 50-323/91-37

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: October 10 through November 18, 1991

Inspectors: H. Wong, Senior Resident Inspector

M. Miller, Resident Inspector

Approved by: P. J. Morrill 12/13/91
P. J. Morrill, Chief, Reactor Projects Section 1 Date Signed

Summary:

Inspection from October 10 through November 18, 1991 (Report Nos. 50-275/91-37 and 50-323/91-37)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, follow-up of onsite events, and selected independent inspection activities. Inspection Procedures TI 2515/101, TI 2515/103, 41500, 61726, 71707, 62703, 71710, and 93702 were used as guidance during this inspection.

Safety Issues Management System (SIMS) Items: The licensee's responses to Generic Letter 88-17 were reviewed. Temporary Instructions 2515/101 and 2515/103 were closed (Paragraph 9).

Results:

General Conclusions on Strengths and Weaknesses: The licensee's startup testing of Unit 2 was performed with good coordination and communications between engineering and operations personnel. Management involvement in the testing was evident. Detailed tailboards were performed to assure that those involved understood the tests. No significant weaknesses were identified.

Significant Safety Matters: None.

Summary of Violations and Deviations: None.

Open Items Summary: One new open item; no items closed.

DETAILS

1. Persons Contacted

   *J. D. Townsend, Vice President, Nuclear Power Generation & Plant Manager Diablo Canyon Power Plant
   *D. B. Miklush, Manager, Operations Services
   *M. J. Angus, Manager, Technical Services
   B. W. Giffin, Manager, Maintenance Services
   *D. H. Oatley, Manager, Support Services
   W. G. Crockett, Instrumentation and Controls Director
   *W. D. Barkhuff, Quality Control Director
   *R. P. Powers, Mechanical Maintenance Director
   D. A. Taggart, Director Quality Performance and Assessment
   T. L. Grebel, Regulatory Compliance Supervisor
   H. J. Phillips, Electrical Maintenance Director
   *J. A. Shoulders, Onsite Project Engineering Group Manager
   S. R. Fridley, Operations Director
   R. Gray, Radiation Protection Director
   J. V. Boots, Chemistry Director
   *J. J. Griffin, Senior Engineer, Regulatory Compliance
   D. K. Cosgrove, Safety and Emergency Services Supervisor
   R. W. Hess, Assistant Onsite Project Engineer
   J. B. Hock, Manager, Nuclear Safety and Regulatory Affairs
   *T. A. Moulia, Assistant to Vice President Operations
   J. M. Welsch, Operations and Engineering Training Supervisor
   R. P. Flohaug, Senior Quality Assurance Supervisor

   *Denotes those attending the exit interview.

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

2. Operational Status of Diablo Canyon Units 1 and 2

   Unit 1 was at 100% power for essentially the entire inspection period, with the exception of a few days (November 2-5 and 9-10, 1991). During those periods reactor power was reduced to 50% to perform cleaning of the circulating water tunnels.

   Unit 2 started the inspection period in Mode 5 (refueling outage 2R4), and the reactor was brought critical on October 20. Full power was reached on October 31. This was the shortest refueling outage in Diablo Canyon history. Unit 2 continued at 100% power for the remainder of the inspection period.

3. Unusual Event Declared Due to Grass Fire (93702)

On November 12, 1991, at 2:00 p.m., an Unusual Event was declared by licensee personnel due to a grass and brush fire within the site boundary which required offsite assistance. At 10:00 a.m. that day, licensee personnel working with personnel from the California Department of Forestry started a "controlled" burn of brush and grass in a hilly area outside the plant protected area, but within the site boundary. At approximately 1:30 p.m., higher than expected winds caused the fire to jump across the fire break lines. Additional equipment from the California Department of Forestry was requested. The California Department of Forestry provided an airplane to drop fire retardant, a helicopter to drop water, additional fire engines and bulldozers, and additional crews. At approximately 4:00 p.m. on November 12, 1991, the fire was declared out. The Unusual Event was terminated at 4:03 p.m..

The fire burned an additional 7 acres beyond the 25 acres originally planned. Plant equipment, structures, and transmission lines were not in jeopardy. The NRC inspector monitored the licensee's response to the event and determined that the control room personnel were maintaining close communications with the fire marshal overseeing the fire fighting activities.

No violations or deviations were identified.

4. 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 to evaluate trends. This operational information was then evaluated to determine if regulatory requirements were satisfied. Shift turnovers were observed on a sample basis to verify that all pertinent information of plant status was relayed to the oncoming crew. 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 work activities.

During these plant tours the NRC inspector noted on two occasions that extension cords had been routed into the Unit 2 diesel generator room through the ventilation openings from the outside. These extension cords appeared to be associated with construction activities for the installation of the sixth diesel generator. In one case, the extension cord had been plugged into a wall outlet, and the extension cord was run through the CO_2 suppression system rolldown door area and near the diesel fuel oil transfer switches. The inspector was concerned that the extension cords might present a fire hazard or reduce the effectiveness of the CO_2 suppression system. When this concern was brought to the licensee's attention, the extension cords were removed.

The NRC inspector also noted that the seal on the handwheel for manual valve 8728B (Unit 1 residual heat removal pump 1-2 discharge valve) was missing with the valve in its required open position. Licensee personnel subsequently reattached the seal. Based on this finding and other licensee findings of missing seals, the licensee performed a verification of approximately 100 sealed valves (approximately 30% of the total number of sealed valves) and found no additional cases of missing seals.

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 verified that health physics supervisors and professionals conducted frequent plant tours to observe activities in progress and were aware of significant plant activities, particularly those related to radiological conditions and/or challenges. ALARA considerations were found to be an integral part of each RWP (Radiation Work Permit).

c. Physical Security

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.

5. Onsite Event Follow-up (93702)

a. Missed Containment Atmosphere Sample - Unit 1

On November 3, 1991, at 2:00 a.m., licensee personnel identified that manual containment atmosphere samples had not been properly taken as required by Technical Specifications (TS) in that the manual samples were drawn using a sample cart when the containment isolation valves were closed. A representative sample of the containment atmosphere could not be obtained with the containment isolation valves closed. Containment isolation valves FCV-678, 679, and 681 were closed due to work being performed on the containment particulate and gas radiation monitors and on the sample pump associated with the monitors.

TS 3.4.6.1 specifies that when a containment atmosphere monitor is inoperable, plant operations may continue for up to 30 days as long as manual samples of the containment atmosphere are taken and analyzed every 24 hours. If manual samples are not obtained, the TS specifies that the plant should be shut down to hot standby conditions within the next six hours and to cold shut down conditions within the following 30 hours. The containment isolation valves were closed on November 1 at approximately 4:50 p.m. and based on the results of containment atmosphere tests, the licensee has concluded that the last valid sample was drawn on November 2 at 12:40 a.m.. When subsequent manual containment atmosphere samples were drawn on November 2 and 3, the containment isolation valves were apparently closed (based on the sample results showing no activity). Therefore the samples did not represent containment atmosphere. Procedures specified that the containment isolation valves were to be verified to be open; however, this was not done. Approximately 26 hours elapsed between when the last valid containment atmosphere sample was taken and when the closed isolation valves were identified and another valid sample taken. The results of the samples showed acceptable activity levels in containment; therefore, there was minimal safety impact due to the missed sample. However, this event revealed several weaknesses..

- The operation of the manual sampling system can allow a recirculation flow path to be established such that a normal sample flow rate is indicated even with the containment isolation valves closed. Technicians thought the isolation valves were open based on the indicated flow rate and did not verify valve positions although procedures specified that the proper valve positions be verified. Subsequent testing by the licensee appears to indicate that the recirculation flow is not significant during operation of the manual sample cart with the containment isolation valves open.

- Technicians who obtained a sample on November 2 at 12:47 p.m. were not sensitive to the results which showed no activity. This result was not consistent with past samples and could have led to the earlier identification of the closed containment isolation valves.

- Communications between operations and chemistry/I&C were not adequate to ensure that appropriate compensatory measures were taken when the containment isolation valves for the sample line were closed.

The licensee's evaluation of the event is described in NCR DC1-91-TC-N098. The licensee has concluded that this event is not reportable. The inspectors concluded that this item was not a violation of the technical specifications since a valid sample was taken before the six hour action statement would require shutdown to hot standby.

b. Steam Introduced Into Nitrogen System Piping - Unit 2

During plant heatup of Unit 2 on October 15, 1991, a smoke detector alarmed inside containment. Upon investigation by licensee personnel, the paint on nitrogen system piping in containment was noted to be smoking. It was also noted that the nitrogen fill valves to steam generator 2-2 (valves 2013 and 906) were open. This allowed steam at approximately 400 degrees F and 400 psi from steam generator 2-2 to enter the nitrogen system piping. Licensee personnel closed the nitrogen fill valves to prevent further heatup of the piping.

The nitrogen line is used to provide a nitrogen blanket for the steam generators during outages and also provides a backup method for operating certain valves in the reactor coolant letdown system. The letdown system valves are inside containment and are normally operated by instrument air. The nitrogen line is not used during normal plant operations, and its outboard containment isolation valve is sealed closed. The nitrogen fill valves were manipulated during system vent and fill operations and apparently were not restored to the closed position.

The licensee performed a detailed walkdown of the nitrogen system piping which included disassembly of some piping connections to determine the extent of steam and water intrusion. The piping arrangement in the plant apparently provided a loop seal which prevented water from reaching solenoid valves for the letdown valve actuators. The licensee evaluated the impact of the elevated temperature and water intrusion on the piping and components in the nitrogen system and determined that the event did not significantly damage piping or components except the nitrogen pressure regulators. The licensee disconnected lines to pressure regulator 5199 and also capped the nitrogen lines to the letdown valves to preclude similar problems in the future. The lines were blown down to remove any remaining water, and the letdown valves were cycled to assure no damage was sustained. The event and evaluation are described in AR A0248331.

The NRC inspector reviewed the licensee's evaluations and had discussions with licensee personnel. The evaluation appeared to be thorough and complete. Based on inspector discussions, the licensee revised procedure AP-9, Loss of Instrument Air, to indicate that the affected letdown valves were no longer provided with a backup nitrogen supply in Unit 2. The inspector had no further questions regarding this event.

No violations or deviations were identified.

6. 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. These activities include:

- Work Order R0096039 - Cleaning CCW Heat Exchanger 2-1
- Work Order R0071268 - CCW Pump 1-2 Oil Sample

No violations or deviations were identified.

7. Surveillance (61726)

a. Observations

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. These tests include:

- STP M-15: Integrated Safeguards Test
- STP R-30: Startup From Refueling (Initial Criticality)
- STP R-6: Low Power Physics Testing
- OP L-2: Hot Standby to Startup Mode
- TP TO-8902, Rev. 1: RHR Water Hammer Testing
- STP I-2D: Power Range Channel Calibration

b. Testing Auxiliary Feedwater (AFW) System Valves

On October 27, 1991, the inspector observed testing of valves associated with the the turbine-driven auxiliary feedwater (AFW) system in Unit 2. The testing was performed to obtain valve performance data in response to NRC Generic Letter 89-10. This testing was performed during power operations (at approximately 30% power) so that steam would be available to run the turbine-driven AFW pump.

Testing was implemented by licensee procedures MP E-99.01, Revision 0, MOV Flow Test - TDAFW Flow Control Valves LCV-106, 107, 108, and 109; MP E-99.02, Revison 0, MOV Flow Test - TDAFW Steam Supply Valves FCV-37, 38, and 39; and STP P-6A, Revision 4, Performance Test of Steam-Driven Auxiliary Feed Pump. The conduct of testing is described in procedure NPAP C-3, "Conduct of Plant and Equipment Tests." The inspector reviewed the test procedures and concluded that the procedures appeared to meet the requirements of NPAP C-3.

The inspector noted that the testing appeared to have been appropriately controlled in that a tailboard discussion was conducted both with the control room staff and with technicians stationed at the valves. Expected plant performance, alarms, and test termination contingency actions were discussed. In addition, a control room shift change was anticipated and during the first tailboard discussion, operators determined the appropriate plant conditions to suspend testing during the shift change. After the shift change, another tailboard was held with the new shift which reviewed the expected plant performance, alarms, and test termination contingency actions. The inspector observed that experience gained from earlier valve testing, regarding minimizing plant transients, was discussed during each of the tailboard discussions. A representative of licensee management was present at each tailboard discussion and during the entire test evolution.

During the changes in plant equipment status and the resulting minor plant transients, operators maintained stable plant conditions and coordination with technicians at the valve stations. Overall control of testing was effective and appeared to maintain the priority on safe operations.

The control room operators conservatively recognized the need to demonstrate valve operability after the restoration of the system back to original conditions and cycled the valves to demonstrate operability.

No violations or deviations were identified.

8. Engineering Safety Feature Verification (71710)

During this inspection period selected portions of the containment spray system for Units 1 and 2 were inspected to verify system configuration, equipment condition, valve and electrical lineups, and local breaker positions.

No violations or deviations were identified.

9. Loss of Decay Heat Removal (Generic Letter 88-17) (TI 2515/101 and TI 2515/103)

a. Background

On October 17, 1988, the NRC issued Generic Letter 88-17 regarding the potential loss of decay heat removal during nonpower operations. This generic letter was due in part to an event at Diablo Canyon in April 1987 which highlighted previously unrecognized concerns associated with reduced reactor coolant system (RCS) inventory conditions. As directed by the generic letter, the licensee responded in submittals dated January 6, 1989, regarding expeditious actions, and on February 6, 1989, regarding programmed enhancements. In addition, the licensee provided supplemental responses in letters dated January 17 and May 31, 1991. NRC letters dated April 26, 1989, and August 22, 1991, document the completion of the NRC's review and acceptance of the licensee's responses.

b. Review

The NRC inspector reviewed the licensee's responses to Generic Letter 88-17 in accordance with Temporary Instructions 2515/101 and 2515/103 to verify completion of the licensee's actions and to verify that training and procedures were appropriate to prevent and mitigate a loss of decay heat removal. Training lesson plans were reviewed, class attendance lists were checked, and a training video tape was reviewed. The inspector reviewed current plant procedures and held discussions with operations personnel to verify the acceptability of procedural limitations, precautions, and actions.

In general, the licensee's training and procedures were found to be complete and adequately covered the areas specified in the generic letter. Because of the licensee's past experience with problems when operating with a reduced RCS inventory, licensee personnel were very sensitive to the potential problems and the need for prompt actions to limit any adverse consequences.

The inspector verified that training had been conducted shortly after the April 1987 event at Diablo Canyon and that reduced RCS inventory training continues to be a part of initial and requalification training for licensed operators. Specific training in this area was conducted for licensed operators just prior to the recent Unit 1 refueling outage which occurred in spring 1991. In addition, training of non-licensed personnel, such as auxiliary operators and maintenance personnel, regarding reduced RCS inventory operations was also verified. There are no specific administrative provisions which require additional training prior to conducting reduced RCS inventory operations. However, based on discussions with licensee personnel, it appears that licensee personnel are sufficiently sensitive to the potential problems that the need for additional training would be considered prior to actually or potentially entering a reduced inventory mode. Such training occurred prior to the Unit 1 refueling outage in early 1991 even though reduced inventory operations were not planned. Further guidance does not appear to be necessary at this time.

The inspector's review of the applicable refueling, abnormal operating, and administrative procedures showed that in general, the guidance contained in the generic letter had been incorporated into site procedures. Appropriate precautions and limitations had been specified to prevent, monitor, and mitigate the consequences of a loss of decay heat removal while under reduced RCS inventory conditions. However, the inspector noted that in some procedures clarification and revision still needed to be performed, and procedures needed to be checked to assure consistency of information. The licensee agreed to evaluate and take appropriate actions to address these issues. The areas of comment are described below:

- New procedures were developed in the areas of outage planning (Administrative Procedure AD8.DC52) and diagnoses of problems with decay heat removal when in Modes 5 and 6 (Abnormal Operating Procedures OP AP SD-0 through 5). These procedures contain additional information not provided in other procedures, such as the need to wait 42 days after shutdown and to have three containment fan cooler units operating if the containment water sealed penetration is to be used.

- Abnormal Operating Procedure AP-16, "Malfunction of the RHR System," needs to be revised to indicate it is applicable only in Modes 1-4.

- Operations Procedure A-2:III, "Reactor Vessel - Draining to Half Loop Operations with Fuel in Vessel," does not have sufficient guidance in establishing and maintaining containment closure for other than the major penetrations. Additional guidance appears necessary to assure that other penetrations which could be open to outside containment, such as when maintenance on valves is being done, are appropriately controlled such that the penetrations could be closed, if required. In addition, operations management recognizes that, because of the limited pressure retaining capability of the penetration using only a water seal, additional guidance is needed to effectively seal the penetration should containment pressurization occur. This penetration is used only during outages to bring temporary lines into containment, such as for steam generator cleaning activities.

- Procedure AP SD-2, "Loss of RCS inventory," should include guidance to open valve HCV-142 to establish a gravity feed flow path to the charging pumps (step 7g).

- Instructions for monitoring and trending RHR pump motor amps are not described in procedures.

- The current mid-loop trouble alarm (PK 02-21A) setpoint specified for RCS temperature is 190 degrees F, although procedure A-2:III specifies that RCS temperature should be maintained less that 160 degrees. In addition, the alarm setpoint for the wide range and narrow range reactor vessel refueling level indication system (RVRLIS) has not been established in the plant computer.

- Current procedures require an additional manager to be present whenever midloop operations are conducted; however, the licensee has informed the NRC that this commitment is no longer necessary based on the administrative actions taken to prevent and mitigate a loss of decay heat removal. This is not yet reflected in procedures.

During discussions with licensee personnel, the NRC inspector was informed that evaluations were being performed to assess the capability of the pathway resulting from the removal of pressurizer safety relief valves to function as the hot leg vent path. This pathway would be in place of detensioning the reactor vessel head studs. Removal of the safety relief valves is being explored as an alternative because detensioning of the reactor head and the associated steps are viewed by the licensee as more complicated and with a higher possibility for errors. Because an RCS vent path as a result of detensioning the reactor head was discussed in the licensee's response to the generic letter, the licensee was requested to inform the NRC in writing should another method of venting be proposed, such as through the safety relief valve openings.

c. Summary

In general, training and procedures covering reduced RCS inventory operations appear appropriate. Progress has been made in the structure of procedures and in refining the previous procedures to reflect more current information and analyses. While this progress appears beneficial overall, procedures are currently in a transition. The licensee stated that appropriate changes to procedures will be made to address the inspector's comments, as well as those changes already being considered. In the past, because the licensee has not planned to perform reduced RCS inventory operations with fuel in the reactor vessel, the procedure revisions have not been a high priority. However, there is a possibility that these reduced inventory operations would be needed unexpectedly due to a steam generator tube leak or reactor coolant pump seal problem. It is expected that the procedures would be reviewed and updated prior to the performance of reduced inventory operations. It is also noted that reduced inventory operation may be planned in the latter stages of the next refueling outages should extended steam generator inspection and maintenance activities occur.

This closes the review of the licensee's responses to Generic Letter 88-17. The licensee's corrective actions to the above comments will be reviewed in future inspections (Followup Item 50-275/91-37-01).

No violations or deviations were identified.

10. Startup Activities - Unit 2 (93702, 71707)

a. High Pressurizer Safety Relief Valve Tailpipe Temperature - Unit 2

During the startup of Unit 2 from the recent refueling outage, licensee personnel noted that pressurizer safety relief valve 8010C had an elevated tailpipe temperature indication of approximately 200-220 degrees F. Total leakage to the pressurizer relief tank (PRT) was monitored and was found to be 0.008-0.025 gpm. Based on previous licensee analyses, a loop seal on the safety relief piping will exist up to a leakage rate of 0.05 gpm.

The NRC inspector had discussions with licensee personnel to determine the significance of the leakage and the monitoring which would be performed during plant operations. Based on these discussions, the licensee will continue to monitor tailpipe temperatures and record PRT in-leakage rates as already provided for in alarm response procedures. In addition, the licensee has installed a containment monitor to display loop seal temperatures to assure that the loop seals exist. Loop seal temperatures will be recorded during routine entries into containment. The NRC inspector verified that the temperature information was being recorded. In addition, the inspector verified that the licensee had provided operators with specific guidance that the relief valves might not be operable if high loop seal temperatures are observed. Current tailpipe temperatures for valve 8010C indicate a downward trend.

Licensee personnel indicated that actions had been taken to resolve the leakage problem and that engineering activities are continuing to determine whether additional system or valve design changes would be beneficial. It is noted that Unit 1 safety relief valves 8010A and B also have elevated tailpipe temperatures (170-180 degrees F). The licensee is monitoring the elevated tailpipe temperatures and is recording PRT in-leakage for Unit 1.

During the above discussions, licensee personnel indicated that an evaluation was being drafted which was intended to demonstrate that safety relief valves would still be operable without loop seals. The licensee plans to submit this evaluation to the NRC when completed.

b. Failure of Feeder Breaker from Auxiliary Transformer to Open - Unit 2

On October 23, 1991, during the attempt to transfer the 4 kV vital bus H from the auxiliary transformer to the startup transformer, the feeder breaker from the auxiliary transformer failed to open. During subsequent attempts to open the auxiliary feeder breaker, the breaker was observed to have smoke coming from the cubicle. The DC control power for the breaker was removed with the breaker still providing power to bus H. The auxiliary feeder breaker was manually tripped, and power was provided to bus H by the startup transformer.

The licensee's investigation of the breaker failure revealed that the trip coil appeared to have become slightly misaligned with the armature assembly. This misalignment could be sufficient to catch the dropping armature, when the trip coil is energized. Since only the force of gravity pulls the armature out of the trip coil, a minor interference or misalignment can reduce the amount of armature travel and cause the breaker to fail to trip. This failure mechanism was demonstrated on another similar breaker.

The failure of this breaker to trip is significant in that power to a vital bus would not be provided. Under plant conditions which would cause a transfer to the startup transformer, such as a fault, the failure of the breaker to open could cause an overcurrent condition if the startup power system attempted to also provide power to the bus or if the fault continued to exist on the 4 kV system. In addition, the diesel generator would be unable to provide power to the bus because of an interlock which prevents diesel generator breaker closure if the auxiliary feeder breaker is closed. Therefore, power to one of the three 4 kV vital buses would not be provided.

The licensee performed testing of the replacement breaker and a visual inspection of the alignment of similar breakers in Units 1 and 2. No other alignment problems were identified. The licensee's evaluation is described in NCR DC2-91-EM-N095. The NRC inspectors verified that visual inspections without breaker removal could determine whether the coil and armature were properly aligned and that the licensee's corrective actions appeared appropriate.

No violations or deviations were identified.

11. Operator Simulator Training (41500)

The NRC inspector observed requalification training for licensed operators which involved a three hour simulator scenario and a one hour critique session (Lesson No. LS-4-5A). The scenario involved the successive loss of a component cooling water system heat exchanger, a generator load reject, a small break LOCA, a large break LOCA, and finally a loss of startup power. This training session involved both operations personnel and training instructors. The crew positions manned were shift foreman, senior control operator, control operator, auxiliary control operator (2), and shift technical advisor.

The training scenario emphasized the use of procedures and the ability of the crew to transition from one emergency procedure to another. The crew demonstrated the understanding of the need to adhere to procedures in a stepwise manner and were able to transition between procedures. The critique session highlighted the technical issues related to the scenario and also the need to follow procedures even for routine evolutions. The inspector noted that in the critique session there was little discussion related to crew interactions or individual performance. Based on discussions with the training supervisor and a supervisor involved in the

training session witnessed by the inspector, it appeared that the licensee recognized that more can be done to strengthen the crew interactions area. The training manager and operations management indicated that this area had been reviewed in the past by the operations director and this area would be given further operations management attention.

12. Exit

On November 22, 1991, an exit meeting was conducted with the licensee's representatives identified in paragraph 1. The inspector summarized the scope and findings of the inspection as described in this report.