U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/89011(DRP); 50-249/89010(DRP)

Docket Nos. 50-237; 50-249 License Nos. DPR-19; DPR-25

Licensee: Commonwealth Edison Company
P. O. Box 767
Chicago, IL 60690

Facility Name: Dresden Nuclear Power Station, Units 2 and 3

Inspection At: Dresden Site, Morris, IL

Inspection Conducted: March 20 through May 26, and June 19, 1989

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6-20-89
Date

Inspection Summary

Inspection during the period of March 20 through May 26, and June 19, 1989 (Report Nos. 50-237/89011(DRP); 50-249/89010(DRP))

Areas Inspected: Routine unannounced resident inspection of previously identified inspection items, plant operations, maintenance and surveillances, licensee event reports followup, Dresden Station management organization, Temporary Instruction (TI) 2515/100, engineered safety feature (ESF) system walkdown, and report review.

Results:

- No violations were identified during this inspection period.

- During this inspection period, three reactor scrams occurred from power. One scram occurred on Unit 2 and two on Unit 3. One of these scrams was considered to be unavoidable (March 25, 1989) due to a failure of a switchyard component not related to station programs. The other two, although not directly related to expected maintenance activities, were contributed to by maintenance.

- A marked decrease in the number of ESF actuations occurred from the previous inspection period.

DETAILS

1. Persons Contacted

Commonwealth Edison Company (CECo)

*E. Eenigenburg, Station Manager
*L. Gerner, Production Superintendent
*C. Schroeder, Technical Superintendent
C. Allen, Administrative Service Superintendent
*D. Van Pelt, Assistant Superintendent - Maintenance
*J. Kotowski, Assistant Superintendent - Operations
G. Smith, Operating Engineer
K. Peterman, Regulatory Assurance Supervisor
*W. Pietryga, Operating Engineer
J. Achterberg, Technical Staff Supervisor
L. Johnson, Q.C. Supervisor
J. Mayer, Station Security Administrator
D. Morey, Chemistry Services Supervisor
D. Saccomando, Health Physics Services Supervisor
E. Netzel, Q.A. Superintendent

The inspectors also talked with and interviewed several other licensee employees, including members of the technical and engineering staffs, reactor and auxiliary operators, shift engineers and foremen, electrical, mechanical and instrument personnel, and contract security personnel.

*Denotes those attending one or more exit interviews conducted informally and formally at various times throughout the inspection period.

2. Previously Identified Inspection Items (92701 and 92702)

(Closed) Open Items (237/87007-02 and 249/87006-02): Control room control console metal facade panels were not properly secured. The inspector visually verified that supports and fasteners had been added to the facade panels. These supports adequately secured the facade panels to the control console main frames and supports. These items are considered to be closed.

(Closed) Violations (237/88012-06; 249/88014-06): The licensee failed to periodically audit the Emergency Operating Procedures (EOP). The inspector verified that quality assurance had included EOPs on the audit and review schedule. These items are closed.

(Closed) Open Items (237/88017-13; 249/88018-13): The NRC Diagnostic Evaluation Team (DET) identified in 1987, that Dresden's improvement plans were not effective for long lasting change in performance. These items are administratively closed based upon improved performance during the previous 20 months and the recent NRC Systematic Assessment of Licensee Performance (SALP) reports (237/89001 and 249/89001).

(Closed) Open Items (237/88017-35; 249/88018-35): The NRC DET identified that the licensee's regulatory assurance department was ineffective in tracking internal and external commitments. The inspector reviewed the licensee's commitment tracking system and found the improvements to be effective. Additionally, the licensee had initiated efforts to audit the closure of previous commitments. These items are considered to be closed.

(Closed) Open Item (249/86012-21): The NRC Safety System Operational Modification Inspection (SSOMI) team inspection identified in 1986, that modification tests did not contain acceptance criteria. The NRC Engineering and Technical Support Inspection Team reviewed modifications performed during the 1988/1989 Unit 2 refueling outage and found that tests contained acceptance criteria. This item is closed based upon inspection reports 237/88021 and 249/88022.

3. Plant Operations (71710, 71707 and 93702)

a. Enforcement History

During this inspection period, no violations were identified in the plant operations functional area.

b. Operational Events

(1) On April 15, 1989, Unit 3 received a reactor scram from 70 percent rated thermal power during weekly surveillance testing of turbine valves. The cause of this scram and the resultant plant response are discussed in detail in Paragraph 4.b.3 of this report.

The operators responded to the event as required by procedures and quickly mitigated the plant upset conditions. The plant was placed in hot shutdown, a known and stable condition, and the main steam isolation valves were closed. In addition, the Oil Circuit Breaker (OCB) from the main generator failed to open on reverse power. Recognizing this failure, the operator manually tripped the breaker.

(2) On March 30, 1989, Unit 3 scrammed from 70 percent rated thermal power due to a loss of Reactor Protection System (RPS) Bus B concurrent with a half-scram condition existing on RPS Channel A. The RPS Channel A half-scram resulted from Main Steamline (MSL) Radiation Monitor A being in a tripped condition. A more detailed explanation of the cause of this scram and the resultant plant response are discussed in Paragraph 4.b.2 of this report.

The operating staff's quick implementation of post-scram actions including placing the mode switch to shutdown prevented receiving a Low Reactor Pressure Group I isolation and allowed the extended use of the condenser as a heat sink. Thus, use of the isolation condenser was not required. In addition, recognizing that the main turbine had failed to automatically trip on reverse power as required, the operators manually accomplished this task.

However, about 45 minutes after the first scram from power occurred, another scram occurred with all rods already inserted due to lack of awareness of system configuration by an operator. Following the first scram, MSL Radiation Monitor A had cleared from the tripped condition on its own and the RPS channel was reset by the operators. However, not knowing this, an auxiliary operator switched RPS Bus A back to its reserve supply in an attempt to clear the MSL Radiation Monitor A trip. The corresponding momentary loss of power to RPS Bus A together with the already existing loss of power to RPS Bus B resulted in this second reactor scram as well as another Reactor Water Cleanup System Isolation, both Reactor Recirculation Pump's Motor-Generator (MG) sets tripping and an Offgas System timer initiation. In addition to returning these systems back to normal, the operators switched RPS Bus A back to its RPS MG Set, reset RPS Bus B Electrical Protection Assembly (EPA) relays and reset the scram.

(3) On March 25, 1989, Unit 3 experienced a fault on 345 KV Switchyard breaker OCB 8-15 which, together with other failures, ultimately led to a trip of Reactor Feedwater Pump (RFP) 3B. The various failures and system responses associated with this event are described in detail in paragraph 4.b.1 of this report.

Following the RFP trip, the operator recognized that feedwater regulating valve (FRV) 3A (which was in automatic) had gone to full open due to decreasing level. Realizing that this response, together with an automatic start of the standby RFP, would result in a rapid increase in reactor water level, the operator began to close FRV 3B (which was in manual) in an attempt to gain control of the level increase. The increase was too quick to gain manual control and the turbine trip setpoint was reached. However, the attempted action represented an excellent understanding of expected plant response on the part of the operator.

Following the turbine trip and resulting reactor scram, the operator took immediate action by isolating the Main Steam Isolation Valves for inventory control (with all RFPs tripped), initiating the isolation condenser for pressure control, and manually starting HPCI for level control. The operator was able to return level from +1 inch to normal range (+30 to +35 inches) and maintain pressure between 800 and 900 psig without lifting any relief valves. The licensee subsequently restored offsite power, secured diesels and initiated shutdown to cold conditions.

c. Approach to the Identification and Resolution of Technical Issues From a Safety Standpoint.

During this inspection period, the operations staff (Shift Engineers and Shift Foremen) took an initiative during a staff meeting to assist the Electrical Maintenance Department in identifying and resolving issues with the station 4 KV breakers. The initiative was based upon the NRC Maintenance Team Inspection finding on the lack of traceability of preventive maintenance on the 4 KV breakers. The Shift Foremen walked down all of the 4 KV breakers and found that the individual breakers did not have external type (1200 or 2000 ampre) identification. Because of this, a detailed audit of all 4 KV breakers was conducted that resulted in the identification of two breakers being installed in the wrong cubicle (a 1200 amp breaker in a 2000 amp cubicle and a 2000 amp breaker installed in a 1200 amp cubicle). The licensee took immediate corrective actions by installing the correct breakers into their respective cubicles and by providing external type identification. Additionally, an evaluation of the safety significance of the issue was conducted. The results of the evaluation demonstrated that all of the design trip functions of the breakers were not affected because the trip relays are internal to the cubicle (external to the breakers) and provided the trip function at the design setting.

d. Responsiveness to NRC Initiatives

During this inspection period, the operations department initiated an interim fourth Nuclear Station Operator (NSO) concept. The licensee had committed to initiate the fourth NSO concept in late 1989, however, due to other activities and commitments, such as operator requalification and the scheduled November Unit 3 refueling outage, the licensee initiated an interim concept early. The interim concept consist of three additional NSOs being assigned to the three shifts during the work week. This concept has been effective in assisting the operating shift in reducing distractions associated with administrative, surveillance and operating tasks. The full NSO concept is scheduled to be initiated prior to September 1989 depending upon the licensing of three additional NSOs.

e. Assurance of Quality, Including Management Involvement and Control

The management's involvement in the initiation of the interim fourth NSO and the 4 KV breaker issue (discussed above) demonstrated very good assurance of quality in the operations of the units.

Additionally, management involvement has resulted in a decrease in ESF actuations (three in the months of March and April compared to six during January and February). However, during this inspection period, the total number of pending work request associated with the control room slightly increased from 25 to 30.

f. Observation of Operations

The inspectors observed control room operations, reviewed applicable logs and conducted discussions with control room operators during this period. The inspectors verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of Units 2 and 3 reactor buildings and turbine buildings were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance.

The inspectors, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. During the inspection, the inspectors walked down the accessible portions of the Low Pressure Coolant Injection and Core Spray systems to verify operability by comparing system lineup with plant drawings, as-built configuration or present valve lineup lists; observing equipment conditions that could degrade performance; and verified that instrumentation was properly valved, functioning, and calibrated. In general, housekeeping has improved with a decreasing number of water leaks within the plant.

The inspectors reviewed new procedures and changes to procedures that were implemented during the inspection period. The review consisted of a verification for accuracy, correctness, and compliance with regulatory requirements.

The inspectors also witnessed portions of the radioactive waste system controls associated with radwaste shipments and barreling.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, 10 CFR, and administrative procedures.

No violations or deviations were identified in this area.

4. <u>Maintenance and Surveillances (62703, 61726 and 93702)</u>

The inspectors observed surveillance testing required by technical specifications for the items listed below and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation were met, that removal and restoration of the affected components were accomplished, that test results conformed with technical specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors witnessed portions of the following test activities:

<u>Unit 2</u>

- HPCI valve operability
- LPCI pump and valve operability

Unit 3

- ° APRM/IRM overlap verification
- ° Diesel Generator operability

Station maintenance activities of safety related systems and components listed below were observed/reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with technical specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented. Work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety related equipment maintenance which may affect system performance.

Various maintenance activities associated with the following events were observed/reviewed:

a. Enforcement History

During this inspection period, no violations were identified in the maintenance/surveillance functional area.

b. Operational Events

(1) On March 25, 1989, with Unit 3 operating at 95% power and Unit 2 at 97% power, the Unit 3 345 KV switchyard experienced a fault on breaker OCB 8-15. The fault resulted in isolation of the affected offsite line from the other two in the switchyard. However, as OCB 8-15 opened, a breaker trouble condition occurred, resulting in opening of the interlocked OCB 8-9, which isolated the reserve auxiliary transformer (TR) 32. This action resulted in the automatic transfer of house busses from TR 32 to the unit auxiliary transformer TR 31.

During the transfer, one of the two operating RFPs, (RFP 3B) tripped due to a failed auxiliary contact on Bus 32. Bus 32 did complete the automatic transfer to TR 31, but was slow enough to trip RFP 3B on undervoltage. The standby pump, RFP 3C, immediately auto started. During the trip of RFP 3B, FRV 3A went to full open. FRV 3A was in automatic and FRV 3B was in manual at 25% open. FRV 3A responded initially because of level decreasing due to RFP 3B tripping and steam rate being equal to 95% reactor power. Reactor water level increased due to the standby RFP start and opening of FRV 3A. The turbine trip setpoint of +55 inches was reached resulting in tripping of the main turbine and a reactor scram (due to turbine control valve fast closure).

Both emergency diesel generators, Unit 3 and Unit 2/3, automatically started upon undervoltage on their busses, 34-1 and 33-1, and recovered the essential busses. However, the (Low Pressure Coolant Injection) LPCI Swing busses, 39-7 and 38-7, attempted to transfer from Bus 39 to Bus 38. The attempt was considered to be a malfunction because Bus 39 was restored by the Unit 3 diesel prior to the 15 second undervoltage time delay relay timing out. Additionally, the transfer to Bus 38 was unsuccessful because one of the two Bus 38 to 38-7 feed breakers failed to close since the breaker linkage was out of alignment. Bus 39-7 was manually restored to Bus 39. (LPCI was not required throughout the event because the unit remained in hot standby and at pressure until offsite power was restored).

During the operation of the isolation condenser, the makeup source was required to be transferred from clean demineralized water to contaminated condensate storage. This resulted in a release from the reactor building and caused ground level contamination within the owner controlled area. The licensee made preparations, prior to the makeup source transfer, to prevent personnel contamination and to monitor/sample the release and contamination. Details of this aspect of the event including subsequent licensee actions are described in inspection reports (IR) 237/89012; 249/89011.

During the event on Unit 3, an annunciator panel fuse blew on Unit 2. Because the power to the annunciator panel was lost for greater than five minutes, the unit was in an alert emergency level. The condition was corrected and the alert was terminated.

(2) On March 30, 1989, Unit 3 scrammed from 70% rated thermal power due to a loss of RPS Bus B concurrent with a half-scram on RPS Channel A. Following surveillance testing of the RPS MG Set EPAs, power supplying RPS Bus A was switched back to its RPS MG Set (normal power) from reserve power. This temporarily de-energized the bus resulting in a half-scram since the reserve feeder breaker opens prior to the normal feeder breaker closing. Upon re-energization, MSL Radiation Monitor A restarted in an unknown trip condition such that the half-scram could not be cleared. An EPA relay supplying RPS Bus B spuriously tripped a short time thereafter. The resultant loss of power to RPS Bus B together with a half-scram from MSL Radiation Monitor A resulted in a full scram. (As part of the surveillance, the tripped EPA had just been tested about a half hour before the scram.) The Reactor Water Cleanup System and Shutdown Cooling Systems received isolation signals on low reactor water level of +8 inches. (Reactor water level dropped to -3.1 inches prior

to recovering.) In addition, the secondary reverse power relay failed to automatically trip the main turbine at -1.3 MWe and thus this was accomplished manually. Recirculation Sample Valves and Isolation Condenser Valves closed and the AC Main Steam Isolation Valve (MSIV) Pilot Solenoids also de-energized. This was due to the corresponding momentary voltage drop on the Instrument Bus when loads swapped from onsite to offsite power following the turbine-generator trip. Subsequent operator actions for this event and a second reactor scram due to a lack of awareness of system configuration by an operator are described in Paragraph 3.b.2 of this report. Almost five hours following the first scram, the same EPA again spuriously opened resulting in another loss of power to RPS Bus B. This caused de-energization of the low reactor pressure bypass relays for the MSIV closure/low condenser vacuum scrams resulting in a third full scram. RPS Bus B was transferred to its reserve feed and the scram was reset.

(3) On April 15, 1989, Unit 3 received a reactor scram from 70% rated thermal power during a weekly turbine valve surveillance. The operator completed testing on the No. 1 Stop Valve (SV) and proceeded to test the No. 2 SV. Immediately upon pressing the closure test switch, all four SVs slow closed, resulting in a reactor scram due to the SV logic and opening of about 75% of the bypass valves due to the resultant pressure transient.

During the event, all systems responded as expected except the main generator. The OCB from the generator failed to automatically open on reverse power.

(4) On April 3, 1989, with the Unit 3 at 99% rated thermal power, the High Pressure Coolant Injection (HPCI) System was declared inoperable due to problems with the Gland Seal Leakoff (GSLO) Pump. One Core Spray Loop had previously been declared inoperable due to a failure of its Minimum Flow Valve to properly open during a surveillance. With both systems inoperable, a technical specification action statement was entered requiring an orderly shutdown to be initiated and reactor pressure to be reduced to 90 psig within 24 hours.

(5) On April 7, 1989, the Unit 2 HPCI system minimum flow bypass valve (2-2301-14) failed to close during a special valve timing test and thus the system was declared inoperable.

This valve is a motor-operated American Society of Mechanical Engineers (ASME) Class 2, 4 inch globe valve, non-Environmental Qualification (EQ) and not required to operate during a Loss of Coolant Accident (LOCA).

(6) On April 12, 1989, the Unit 3 HPCI system was declared inoperable. The unit was operating at about 95% power. During an inspection of EQ junction boxes, the licensee

discovered that the junction box for the HPCI outboard isolation valve contained a terminal block connection instead of the required EQ splice. The terminal block was not EQ qualified. The licensee de-energized the valve in it's containment isolation position (closed) and declared HPCI inoperable.

(7) On May 1, 1989, Unit 2 HPCI system was declared inoperable to perform preventive maintenance on the HPCI room cooler. During routine shift rounds, the operations department identified that the Unit 2 HPCI room cooler's fan drive belt was degrading. The licensee secured the room cooler fan and declared HPCI inoperable.

(8) On May 10, 1989, the Unit 2 HPCI system was declared inoperable for preventive maintenance. The licensee had noted indication of degrading of the HPCI room cooler fan shaft.

(9) On May 6, 1989, Unit 3 began a 23 day scheduled maintenance outage to replace the main transformer. The licensee had detected degrading conditions on the main transformer in mid 1988 via routine predictive maintenance.

c. Approach to the Identification and Resolution of Technical Issues From a Safety Standpoint

The licensee demonstrated a good approach to identifying and resolving the technical issues noted above. Most noteworthy were the resolution of the Unit 2 HPCI room cooler's fan belt (Paragraph 4.b.7) and bearing (Paragraph 4.b.8), and the replacement of the Unit 3 main transformer (Paragraph 4.b.9). All of these demonstrated good effective preventive and/or predictive maintenance in detecting and resolving degrading conditions prior to failure of major equipment. These and other resolutions are discussed as follows:

(1) Licensee actions taken in regard to the Unit 3 March 25, 1989, event when a fault was experienced on OCB 8-15 are described in detail in IR 237/89012; 249/89011.

(2) Following the Unit 3 scrams of March 30, 1989, (as described in paragraph 4.b.2 of this report) the faulty EPA breaker was replaced by one of the reserve feed EPA breakers and RPS Bus B feed was returned to its RPS MG Set. A replacement EPA breaker is being procured for the reserve feed. A calibration check of the faulty EPA breaker showed no abnormalities and it was shipped to the vendor to determine the failure mode. Corrective actions will be taken based on this evaluation. Only one previous EPA breaker failure has occurred and this was caused by poor linkage alignment. The licensee completed maintenance on the Offgas System timer circuitry prior to restarting Unit 3.

Dresden Technical Surveillance Procedures, DTS 500-1, 2, and 3 are being revised by including a caution regarding the potential for lock-up of the MSL radiation monitors and actions to be taken to prevent it. In addition, a study has been undertaken to determine if the radiation monitor lock-up condition can be eliminated by modification of the logic cards.

In reference to the failure of the secondary reverse power relay to automatically trip the main generator, the licensee originally concluded that the operator had manually tripped the relay before the 15 second time delay had timed out. However, following a second failure of the automatic trip during a later scram, the relay was inspected and found to be inoperative because of dirt between the bearing surface and the contact pivot arm surface.

(3) During troubleshooting efforts following the Unit 3, April 15, 1989, reactor scrams, (as described in paragraph 4.b.3 of this report), the maintenance and operations departments tested all of the logic associated with the turbine valves. This effort determined that the master-slave relay associated with the No. 2 SV failed, resulting in all four SVs closing. The SV logic is designed to actuate the Reactor Protection System (RPS) on closure of one or more SVs in either logic channel. The logic has two SVs on each channel and a half scram per channel. Limit switches on the valves trip the channel at less than 95% full open. The No. 2 SV has a master-slave relay that will fully close the other three SVs if No. 2 is less than 95% full open. This allows the No. 2 SV to be used for turbine warmup during startup operations. The master-slave relay was replaced and four subsequent post maintenance tests verified the adequacy of the repair.

Troubleshooting efforts determined that the reason for the main generator not tripping on reverse power was that the trip relay sensing reverse power failed to open the OCBs due to a defective spring in a contact. The relay was replaced and testing verified that the reverse power trip logic was operable. The unit was returned to service on April 17, 1989.

(4) Following entry into the Technical Specification required shutdown for Unit 3 on April 3, 1989, (as described in paragraph 4.b.4 of this report), the licensee determined the HPCI GSLO Pump problem to be due to a stuck thermal overload reset button which caused the auto-trip light to remain on. However, it did not affect operation of the HPCI GSLO Pump itself. The HPCI GSLO Pump was retested and declared operable. Repairs to the Core Spray Minimum Flow Valve were completed on April 3 and the system was returned to service.

(5) Following failure of the Unit 2 HPCI system minimum flow bypass valve on April 7, 1989, (as described in paragraph 4.b.5 of this report) the licensee discovered that a small valve packing leak was condensing on the top of the valve motor casing and seeped into the motor around a casing bolt's thread. The packing was replaced, motor winding dried and the bolt sealed. The valve successfully passed the test and HPCI was declared operable on the same day.

(6) Following discovery of the inappropriate terminal block connection for the Unit 3 HPCI outboard isolation valve on April 12, 1989 (as described in paragraph 4.b.6 of the report), the terminal block (not EQ qualified) was removed and replaced with a EQ qualified splice. The HPCI system was declared operable on April 13.

(7) Following discovery of the Unit 2 HPCI room cooler fan drive belt degradation on May 1, 1989, (as described in paragraph 4.b.7 of this report), the licensee immediately began replacing the fan belt and initiated Technical Specification required surveillance testing of the core spray, low pressure coolant and the automatic depressurization systems. The fan belt replacement and post maintenance testing was completed the same day. The HPCI system was returned to operation and the Technical Specification required testing was terminated.

(8) Following identification of the Unit 2 HPCI room cooler fan shaft degradation on May 10, 1989 (as described in paragraph 4.b.8 of the report,) the licensee began an increased monitoring of the shaft and ordered replacement parts. The monitoring indicated that a fan bearing was degrading and maintenance was scheduled. The HPCI fan was repaired and HPCI returned to service on the same day.

(9) As a result of the degrading conditions on the Unit 3 main transformer (as described in paragraph 4.b.9 of the report,) it was placed on an increased surveillance frequency while a replacement was ordered. The replacement transformer was received onsite in late April 1989 and plans were developed for the maintenance outage. Additional activities during the outage included 4 KV breaker overhauling, repairs to feedwater heater's controls and various control room instrumentation maintenance. The unit was returned to service on May 30, 1989.

(10) On May 19, 1989, an analysis performed as a result of a licensee safety system functional inspection finding determined that the design for a one inch HPCI drain pot line on both units did not meet Final Safety Analysis Report (FSAR) allowables for thermal and seismic considerations. These lines remove condensate from the steamlines supplying the HPCI turbines. A licensee preliminary evaluation indicated that the lines were still operable and a detailed

operability analysis was performed. Modifications to add supports to the drain pot lines were installed on May 21, 1989.

d. Responsiveness to NRC Initiatives

The NRC Maintenance Team Inspection had identified problems associated with preventive maintenance associated with the 4 KV breakers, including the inability to track completion of preventive maintenance because of the practice of tracing maintenance against the cubicle instead of the individual breaker. The licensee corrected their preventive maintenance program for both Units 2 and 3 by tracking component history against the individual identification number of the breakers. Additionally, external identification numbers for all of the Unit 3 4 KV breakers and external type (1200 or 2000 ampre) identification for both Units 2 and 3 were installed during this inspection period. During these efforts, the NRC resident inspectors identified to the licensee that two pairs of Unit 3 4 KV breakers (a pair of 1200 and 2000 amp breakers) had identical manufactured supplied identification numbers.

The licensee contacted General Electric (GE), manufacturer of the breakers, and discovered that in 1964, GE had overlapped serial numbers of several 1200 and 2000 ampre 4 KV breakers. A review of the original receipt documents confirmed that the breakers were received with overlapping breaker serial numbers.

The licensee also overhauled these breakers to confirm that they were not possibly counterfeits. In addition, the licensee verified that no other overlapped GE serial numbered 4 KV breakers existed at the other CECo stations.

The above actions are considered to be very good responsiveness to NRC initiatives.

e. Assurance of Quality, Including Management Involvement and Control

During this inspection period, the licensee demonstrated mixed management involvement in assuring quality in maintenance and surveillance activities. In general, improvements were noted by the examples of the good resolution of technical issues; however, the increased rate of HPCI inoperability (excluding the Unit 2 HPCI inoperability associated with predictive maintenance) and the failure to identify the overlapping of 4 KV breaker serial numbers indicates areas that additional management involvement is warranted.

No violations or deviations were identified in this area.

5. Licensee Event Reports (LER) Followup (92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with Technical Specifications.

(Closed) LER 237/88020: ESF Actuation Due to Loss of Both RPS Busses Caused by Diesel Generator Fuel Filter Fouling. The standby gas treatment system started and the reactor building ventilation system isolated when both RPS busses de-energized when EPAs tripped on under-frequency. The reactor building and refuel floor radiation monitors are fed from the RPS. At the time of the event, the unit was shutdown with both RPS busses being fed by the Unit 2 diesel generator (DG). The cause of the event was a fouled Unit 2 DG fuel filter which caused the DG speed and, therefore, frequency to drop below the RPS EPA relay setpoint. The vendor indicated that fouling of a fuel filter was not uncommon for a DG run of the duration that Unit 2 experienced, which was approximately 100 hours. The immediate action was to switch to the other fuel filter (duplex filter design), and reset the systems. The High Voltage Operator's Round Book was revised to include monitoring fuel pressure when the DG is running and to switch fuel filters if the pressure exceeds a specified value. Also, the filters can be replaced while the DG is running, if necessary. Although not discussed in the LER, the licensee is evaluating the appropriate frequency to clean/inspect the fuel oil storage tanks to remove any accumulated sediment. Two of the three storage tanks were cleaned in 1989 with the last scheduled to be cleaned in June 1989. This event was the first in which a fuel filter had an adverse effect on DG operation at Dresden. This LER was reviewed and found to be satisfactory.

(Closed) LER 237/89001: Inadvertent ESF Actuation Due to Procedural Deficiency. On January 21, 1989, with Unit 2 in a refuel outage, an unanticipated scram and Group II Primary Containment Isolation occurred when both 2A and 2B RPS MG sets were lost by a time overcurrent trip of Bus 29 and Bus 28, which, at the time, was being powered through Bus 29. This event is described in IR 237/89005. The cause was determined to be an improper tap setting that had been made during a recent relay calibration and failure to verify the return to the normal tap setting following the calibration. This was attributed to an improper procedure which has been revised to include independent verification of the as left condition of the relay setting following relay calibration. During the return of 2B RPS Bus to normal feed (2A MG Set), it was found that the breaker thermal overloads had tripped. Electrical Maintenance tested and replaced the thermal overload relays and replaced a contractor contact assembly to return the breaker to satisfactory operation.

*(Closed) LER 237/89002: Setpoints on Main Steam Safety Valves Found Outside Technical Specification Limits due to Setpoint Drift. During the regular testing of one half of the safety

valves each refueling outage, two valves exceeded the TS pressure limits, one above the one percent tolerance and one below the specified tolerance. However, both of these valves met the ASME Section XI Performance Test Code 25.3-1976 tolerance of +/-2 percent of set point and the safety significance of this event is minimal based upon a CECo evaluation which concluded that the as found setpoints would have relieved the pressure well before the pressure limit was reached.

The safety valves were overhauled, tested and setpoints verified using a revised procedure that now requires valve opening adjustment to be as close to the design setpoint as reasonably achievable.

(Closed) LER 237/89003: Anticipated Transient Without Scram (ATWS) Actuation Due to Procedural Deficiency. This event as described in IR 237/89005, occurred January 31, 1989, during required maintenance on a flow check valve in the Alternate Rod Insertion System with all control rods inserted. It was caused by improper valve-out of the reactor level ATWS transmitters. Because of a similar event on Unit 3, LER 249/88016, training had been given on how to properly valve out a differential pressure instrument; however, the training was not followed in this instance. The channel was reset by opening the equalizing valve. A new procedure is scheduled to be developed before the next refuel outage to give the proper valving sequence to take various level transmitters out-of-service. This event was included in the Licensed Operator continuing training program as Package 89-15.

(Closed) LER 237/89004: Unexpected Reactor Scram During Bus Undervoltage Test Due to a Spurious Intermediate Range Monitor (IRM) Spike. This event occurred on February 4, 1989, during undervoltage and Emergency Core Cooling System (ECCS) Integrated Functional tests for Unit 2/3 Diesel Generator and was reported in IR 237/89005. During the testing and while Channel B was tripped as expected, Channel A received a trip from a spurious spike of IRM 13 which initiated the reactor scram. The IRM spike was attributed to an induced signal resulting from the initiation of the Standby Gas Treatment system (SBGT) during the bus undervoltage test and was caused by an inadequately shielded signal cable. The signal cable was subsequently replaced with a triple shielded cable and has since exhibited satisfactory performance.

(Closed) LER 237/89005: Inadvertent Injection of ECCS Into the Reactor Vessel Due to a Leaking Test Valve. This event occurred February 5, 1989, during the performance of the Bus Undervoltage and ECCS Integrated Functional test for the 2/3 Diesel Generator during preparations for restart after refueling (IR 237/89005). A simulated drywell high pressure was applied to the drywell pressure switches using a test rig. The high pressure signal was generated prematurely, initiating the Unit 2 and 2/3 Diesel Generators, the 2C and 3D LPCI pumps, and the 2B Core Spray pumps injecting water into the reactor vessel. The cause was determined to be a leaking inlet test valve and an improperly positioned vent valve which allowed the test pressure to build up prematurely and trip the pressure switches. The injections were promptly stopped, the pressure bled off, and the lineup returned to normal. A new test rig will be fabricated with valve positions clearly labeled and the test procedure revised to require the air supply valve to remain closed until the test pressure is needed. The event is being reviewed during the current Licensed Operator Continuing Training Program cycle.

(Closed) LER 237/89006: Inoperative Control Rod Drive (CRD) Hydraulic Control Unit Charging Header Ball Check Valves Due to Procedural Deficiency. During inservice testing of the CRD system while refueling, three charging water header ball check valves failed the leak test. Two were found to have no ball in the valve and in the third the ball was scratched. During normal operating conditions, scram insertion times would not be affected with loss of the check valve; however, when the reactor pressure is low i.e., during startup the control rods may fail to insert without assistance from the scram accumulator pressure if the CRD pumps were inoperative. It is not likely that the balls were worn away or had disintegrated because they are fabricated of stellite, a cobalt, chrome and tungsten tool steel which is much harder than the 304 stainless steel valve body.

Thus, the balls were evidently not installed during maintenance work. The check valves are disassembled if needed for maintenance and when the seat of the scram inlet valve is replaced. The last such maintenance on one valve was August 1986 and maintenance records for the other valve were not found. Corrective actions taken to prevent recurrence of this event included revision of Dresden Maintenance Procedure, DMP 300-18, CRD Inlet and Outlet Scram Valve Maintenance to include verification of the ball replacement, development of a maintenance procedure for the inspection/rebuilding of the charging water header check valve which will include a sign off for verification of ball installation, and three Dresden Operating Procedures were revised to manually scram the reactor should any accumulator trouble lights illuminate when the mode switch is in startup and the CRD system pressure is lost and cannot be immediately restored. The three faulty check valves were repaired and tested satisfactorily.

*(Closed) LER 237/89007: Unsatisfactory Main Steam Relief Valve Pressure Setpoints Due to Instrument Drift and Limit Switch Failure. While performing Electromatic Relief Valve (ERV) calibrations during a refueling outage, three valves were found outside the Technical Specification set point error limit of +/- one percent. Two failures were attributed to setpoint drift and the other to an erratic pressure switch. The set points are adjusted by spring tensioned screws that by age and pressure switch vibration tend to drift from their original settings and

in this instance the drift was to a lesser pressure or a conservative direction. In recalibrating the switches, the as-left setting was biased toward the plus tolerance setting. The third pressure switch was found to be damaged by electrical arcing which led to unstable limit switch operation with erratic setpoint actuations. This switch was replaced and calibrated. An industry wide search on pressure switch performance indicated there had been 42 events of setpoint drift and only 2 events attributed to switch failure. The significance of this LER is minimal since the drift is to a lower pressure and the relief valves setpoints are adjusted to relieve reactor vessel pressure before the safety valves trip at a higher pressure.

*(Closed) LER 237/89008: Unexpected Power Increase Upon Entering the Remote Load Following Mode Due to Procedural Deficiency. On March 14, 1989, with Unit 2 at 94 percent rated power, the reactor recirculation system was put into master automatic mode and the unit into Economic Generation Control (EGC). The EGC system is a remote load following mode controlled from the System Load Dispatcher's office whereby the reactor recirculation flow can be automatically controlled by the system load between 65 and 100 percent rated core flow and within pre-selected limits of power level and power rate change. When the switch was made to EGC, the operator observed that the generator load had increased to 25 MWe above the pre-selected upper generator load limit of 805 MWe. The unit was immediately removed from the EGC mode and power reduced manually but not before the Technical Specification limit of 100 percent of rated core flow while in EGC and above 20 percent power was slightly exceeded. The safety significance was minimal because the maximum core thermal power limit and none of the nuclear fuel limits were exceeded. It was subsequently determined that if entry into the EGC modes are made immediately following placing the recirculation flow control into master automatic, insufficient time for control stabilization may result in overshoot of the upper generator load limit. Corrective actions taken to prevent recurrence was to revise Dresden Operating Procedure DOP 5670-1 Revision 2, EGC Operations to require a stabilizing time period before entry into EGC and close monitoring following entry. The revision will also require selecting a computer generated alarm to provide annunciation prior to exceeding pre-selected generator load limits. The procedure DOP 202-3 Revision 5, Reactor Recirculation Flow Control System Operation, was also revised to provide similar precautions. This event was also summarized and issued to all licensed operators by a memo dated April 14, 1989.

*(Closed) LER 237/89009: Unplanned Group V Primary Containment Isolation During Surveillance Testing Due to Spurious Isolation Signal. With Unit 2 shutdown for a scheduled refueling outage, a Group V primary containment isolation occurred, isolating the isolation condenser from the reactor vessel. The event occurred concurrent with the performance of an Isolation Condenser Instrument Flow Check Valve surveillance. Reactor pressure was 600 psig with all control rods fully inserted and there was

neither steam or condensate flow in the isolation condenser piping at the time of the event. The Group V primary containment isolation was immediately reset and all associated valves were returned to their normal positions. The cause of the Group V isolation has been hypothesized to be either an air bubble entrained in the differential pressure indicating switch sensing line or that the instrumentation at the rack was inadvertently jarred. A four hour notification was required but was not performed for 10 hours. The cause of the delay in completing the four hour notification was attributed to a miscommunication and misinterpretation of the reporting requirement by the operations personnel. The event was initially determined not reportable as it had occurred during surveillance testing. This event was reviewed with instrument maintenance department personnel and all station personnel in order to emphasize the potential for unplanned engineered safety feature actuations during surveillance testing. Additionally, this event was included in the Licensed Operator Continuing Training Program in order to review the need for prompt reporting of all unplanned ESF actuations.

(Closed) LER 237/89010: Unexpected Group V Primary Containment Isolation During Maintenance Work due to Management Deficiency. During the Unit 2 refueling outage with the unit in cold shutdown mode, an unexpected Group V primary containment isolation occurred thereby isolating the isolation condenser from the reactor vessel. The event occurred due to a management procedural deficiency during the performance of maintenance on isolation condenser instrument flow check valves for differential pressure switches. Upon review of the equipment outage checklist, it was observed that the maintenance foreman had not requested appropriate isolation points and an additional out-of-service was prepared which inadvertently isolated the high condensate flow switch. It was later discovered that the incorrect switches were taken out of service due to lack of clarity in the valve labeling involved. The cause of this event was attributed to management deficiency in making up the outage checklist and to improper valve labeling. To prevent recurrence, the equipment labels will be changed to more accurately describe the differential pressure indicating switches. This corrective action will also be done on Unit 3 instrumentation. Also, to emphasize the importance of properly removing instrumentation from service that could result in an engineered safety feature actuation, this event was reviewed with all station departments during a tailgate meeting.

(Closed) LER 237/89011: HPCI GSLO Condenser Drain Pump Failure Due to Degraded Motor Starting Circuit Capacitor. With Unit 2 at 99% rated core thermal power, it was observed that the HPCI GSLO condenser drain pump would not trip off automatically on decreasing GSLO condenser hotwell level or by manual control switch manipulation. The pump was secured by opening the power supply breaker and the HPCI system was declared inoperable. The root cause of the problem was determined to be a degraded capacitor which allowed excessive current to fuse the time armature contact and the two motor contacts. During the investigation it was also determined that the local "stop" push button was not wired as indicated by the schematic diagram. The safety significance of this event is minimal since automatic operation of the HPCI system was not affected and other ECCS were not effected. To prevent the reoccurrence of this event, the GSLO pump motor armature resistance short out contractor and capacitor were replaced, the motor contacts were inspected for pitting, and a logic check of the GSLO condenser drain pump circuit was performed. The pushbutton wiring was changed to reflect the current electrical schematic. Fifteen work requests were initiated for replacement of similar capacitors associated with Cutler-Hammer direct current motor starters. A procedure inquiry was initiated to evaluate Dresden Maintenance Procedure, DMP 8300-3, Inspection and Maintenance of Cutler-Hammer Direct Current Motor Starters, for the inclusion of capacitor testing and a periodic preventive maintenance replacement of the capacitor.

(Closed) LER 237/89012: Reactor Scram on Low Reactor Water Level Due to a Personnel Error During 125V DC Ground Checking. During the checking for grounds on the 125V DC battery system, the Reactor Feedwater (RF) Controller breaker was opened by error which tripped both RFPs on simulated low oil pressure. The standby 2C RFP started automatically but when the 2A RFP was restarted, both pumps tripped on low suction pressure. The 2A RFP was restarted again and the 2C restarted automatically, but the reactor scrammed on low reactor water level and Group II and III Primary Containment Isolations (PCI) were received. The reactor water level recovered from a low of -15 inches and the RFPs and turbine tripped on high water level. The main generator tripped on reverse power and all house loads were transferred to the reserve transformer. During this transfer the MSIV closed and a Group V PCI occurred isolating the Isolation Condenser. The Group V PCI was reset and the Isolation Condenser automatically initiated at the 1070 psig setpoint. Plant systems responded as expected on the events encountered during the transient and ECCSs and Emergency Diesel Generators (EDG) were operable at the time. The MSIV closure was caused by the DC pilot solenoids being de-energized by the ground checking and the AC pilot solenoids were de-energized by the voltage dip when the house loads were transferred.

The Group V PCI was also caused by the error in breaker switching. Corrective actions taken included the emphasis on attention to detail and adherence to procedures during discussions of the event with the personnel concerned as well as all other shift personnel. The breakers were labeled with red tape before the unit was restarted and permanent labels of white lettering on a red background were scheduled for all breakers on circuits having potential to cause a scram. The DC ground checking procedures are scheduled to be reviewed and revised if necessary to assure proper breaker sequencing and the revised procedures will be posted at the DC switchgear locations (this event and the resulting Notice of Violation is documented in IR 237/89005).

(Closed) LER 237/89013: Possible Single Failure Loss of Both Standby Gas Treatment (SBGT) Systems Due to a Design Deficiency. During a design review of SBGT power supplies started on February 21, 1989, the licensee found that in the unlikely event of Unit 3 loss of coolant accident (LOCA) concurrent with a loss of offsite power (LOOP) to Unit 3, and a failure of the Unit 2 125V DC battery system, both the A and B SBGT trains would be inoperable. Because of the very low probability of the above failures occurring concurrently (upper bound estimate 2.4 E-10 per year) and the limited radiological consequences with the SBGT inoperable during a LOCA, operations were continued and a Justification for Continued Operations submitted to NRC on February 23, 1989. Dresden General Abnormal Procedure, DGA 4, Loss of the Unit 2 125V DC System During a LOCA Concurrent With a Loss of Offsite Power to Unit 3, was issued February 24, 1989, and training to all shifts completed. This procedure directs the necessary manual switching to obtain emergency power to the B SBGT System if the above event sequence should ever occur. In addition, Modification Request R12-2-89-20, was issued to change the SBGT Train A 480V power feeds to a bus fed by the Unit 2 Diesel Generator. This change will eliminate the dependance of both SBGT systems to a single battery system. This modification is being scheduled for installation during the December 1989 dual outage.

(Closed) LER 237/89014: HPCI Minimum Flow Valve MO2-2301-14 Inoperable Due to Moisture Intrusion into the Motor Operator. During quarterly valve timing tests on April 7, 1989, the subject valve was found to be inoperable due to the valve breaker being tripped from a thermal overload condition. The HPCI system was declared inoperable and Unit 2 entered a seven day LCO. This valve is normally closed and opens when HPCI flow is less than 600 gpm and closes above 1200 gpm. During normal HPCI startup without the valve being operable, the pump would be dead-headed for about 10 seconds but this would not impact continued operation of the HPCI system. Cause of the overload condition was found to be moisture intrusion into the valve motor from ceiling/foundation leakage into the HPCI area. The valve motor was immediately dried, reinstalled and tested. A temporary funnel was installed to prevent water from reaching the motor. The HPCI was declared operable on the same day.

The ceiling leak has been scheduled for repair and the motor will be painted in order to seal any moisture entry points.

(Closed) LER 249/89002: Reactor Scram Due to the Failure of an EPA Breaker. On March 30, 1989, with Unit 3 at 70% power, a surveillance test of the RPS MG Set and RPS Reserve Power Supply for RPS Bus A had been completed and Bus A had been returned to normal power but the half scram on Channel A could not be reset because of a tripped and locked-up Main Steam Line (MSL) Radiation Monitor. Before the Channel A half scram could be cleared, a spurious trip of EPA Breaker 3A-1 occurred on RPS Bus B which resulted in a reactor scram. The details of this event are discussed within Paragraphs 3 and 4 of this report.

(Closed) LER 237/89015: Trip of the 2A Reactor Protection System (RPS) Motor Generator (MG) Set Due to High Ambient Temperatures. The cause was determined to be high ambient temperatures (warm weather and ventilation configuration) in the area of the Motor Control Center (MCC) resulting in tripping the thermal overloads for the 2A RPS MG set on both April 21 and 25, 1989. Short term corrective action was to increase the thermal overload heater one size and increase the trip setpoint. Long term corrective action will be to install ambient compensated thermal overloads to preclude trips due to warm weather conditions.

(Unresolved) LER 249/89005-00: HPCI System Declared Inoperable Due to Discovery of Cable Terminal Blocks That Were Not Environmentally Qualified. Two unqualified terminal blocks that were not environmentally qualified (EQ) were discovered by the licensee in a cable pull box for the High Pressure Coolant Injection (HPCI) system during a response to an NRC concern regarding box weep holes. Corrective actions included replacing the unqualified terminal blocks with EQ taped splices and initiating an extensive inspection on all EQ equipment to determine if there are additional unqualified components installed for either Units 2 or 3. Inspection Report 237/89010; 249/89009 further discusses NRC inspection of this issue/event.

(Closed) LER 249/89006-00: Reactor Scram Caused By Turbine Stop Valve Closure Due to Control Relay Failure. The cause was determined to be component failure. A control relay failed to close in the Turbine Stop Valve (TSV) Test Logic causing the TSVs to close and initiation of a scram signal. In addition, the main generator output breakers failed to open on reverse power for the second time (LER 249/89002-00) because of dirt causing mechanical binding of the contact pivot arm on the relay directional unit. Corrective actions included replacing the control relay, cleaning the contact pivot arm, and clarifying the relay calibration procedure to specifically address the mechanical binding of the relay pivot arm.

*Denotes those preceding LERs that were reviewed against the criteria of 10 CFR 2, Appendix C, and the incidents described met all of the following requirements. Thus no Notice of Violation is being issued for these items.

a. The event was identified by the licensee,
b. The event was an incident that, according to the current enforcement policy, met the criteria for Severity levels IV or V violations,
c. The event was appropriately reported,
d. The event was or will be corrected (including measures to prevent recurrence within a reasonable amount of time), and
e. the event was not a violation that could have been prevented by the licensee's corrective actions for a previous violation.

No violations or deviations were identified in this area.

6. Dresden Station Management Organization

During the inspection period, CECo reorganized the corporate and station organization. The reorganization included changes in titles or personnel or functions. Listed below is the current Dresden Station Management Organization.

	E. Eenigenberg, Station Manager
(f,t)	C. Schroeder, Technical Superintendent
(p,f,t)	E. Mautel, Services Director
	L. Gerner, Production Superintendent
	D. VanPelt, Assistant Superintendent - Maintenance
	J. Kotowski, Assistant Superintendent - Operations
(p)	J. Achterberg, Assistant Superintendent - Work Planning
(f,t)	C. Allen, Administrative Service Superintendent
	K. Peterman, Regulatory Assurance Supervisor
(p)	M. Strait, Technical Staff Supervisor
(p)	L. Johnson, Quality Control Supervisor
	D. Saccomando, Health Physics Services Supervisor
	D. Marey, Chemistry Services Supervisor
	S. Stiles, Training Supervisor
	M. Dillon, Fire Marshall
	J. Smith, Operating Engineer
	W. Pietryga, Operating Engineer
	B. Zank, Operating Engineer
(p)	J. Williams, Operating Engineer
(p)	R. Geier, Master Mechanic
	D. Booth, Master Electrician
(p)	D. Gulati, Master Instrument Mechanic
	E. Netzel, Quality Assurance Superintendent

Note:
(p) denotes personnel change
(f) denotes change in function of position
(t) denotes change in title of position

7. TI 2515/100 - Proper Receipt, Storage and Handling of EDG Fuel Oil (FO) (255100)

The purpose of the subject temporary instruction was to survey licensee's results to selected EDG FO issues on a questionnaire supplied with the TI. The inspectors reviewed the licensee's Quality Assurance (QA) program, FSAR and Technical Specifications to determine the licensee's requirements and commitments in this area. Once the requirements were determined, the inspectors compared the licensee's implementing procedures against these requirements and commitments to ascertain program compliance. The inspectors filled out the required information on the questionnaire and forwarded it to Office of Nuclear Reactor Regulation (NRR).

The Dresden Technical Specifications require that a monthly FO sample be checked for quality. However, the Technical Specifications do not specify acceptance criteria for what constitutes quality. The licensee determines FO viscosity and analyzes for water, sediment and microbes on a monthly basis for the day and storage tanks.

The licensee has established a preventive maintenance (PM) program for filters and strainer cleaning and/or replacement using Dresden Maintenance Procedures (DMP) 6600-2, 3 and 4. A number of these have been deferred due to the preference to leave the DG in service as opposed to taking it out of service to perform the PMs. The licensee is currently drafting a procedure for PM deferrals and justifications.

No violations or deviations were identified in this area.

8. ESF System Walkdown (71710)

The inspectors walked down the accessible portions of the Unit 2 Standby Liquid Control (SBLC) system to verify operability by comparing system lineup with plant drawings, as-built configuration, and operations checklist DOP 1100-E1 and M1; observing equipment that could degrade performance; and verifying that instrumentation was properly valved, functioning, and calibrated. The inspectors also observed plant housekeeping/cleanliness conditions and radiation protection practices.

The inspector noted a number of errors and/or omissions in the Unit 2 SBLC checklist, DOP 1100-E1 and M1, Revision 0 and Revision 5, respectively. Examples include incorrect valve numbers listed on the checklist, not stating a valve is locked, and not stating that there are two valves with the same label and both need to be checked. Also plant drawing M-33 failed to show that several valves were locked in their position as existed in the plant and as stated in DOP 1100-M1. All of these discrepancies were discussed with the System Engineer for resolution, who also plans on reviewing Unit 3 for similar discrepancies.

The inspector noted no actual SBLC lineup problems. The checklist problems were of a type that should not have misled a trained operator. In general, housekeeping was adequate with the exception of some boron crystals on the pump base, temperature switch connection, and a few valves. Also of note was a problem identification tag dated April 8, 1987, for the replacement of the SBLC storage tank sight glass gallon scale. Since this is used for local level readings, it should have been repaired in a timely fashion. Several of the SBLC instruments were not labeled.

Periodic instrument calibrations are performed by procedures DIS-1100-1 through 3; however, the SBLC instrumentation are not included in these procedures. These instruments require calibration only after maintenance had been performed that affected specific instrumentation. A review of the calibration records maintained by the Instrument Maintenance (IM) Department revealed that all but two of the instruments received calibration at a frequency of approximately every two years by this program. The other two instruments were last calibrated over seven years ago. This program does not appear to provide good assurance of all of the instrumentations' calibration. Discussions with the licensee revealed that the instrument calibration program, part of the current preventive maintenance program upgrade, is in the process of being revised. The licensee agreed to ensure that the SBLC instrumentation is included in their review of the calibration program.

No violations or deviations were identified in this area.

9. Report Review

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Reports for March and April. The inspectors confirmed that the information provided met the requirements of Technical Specification 6.6.A.3 and Regulatory Guide 1.16.

10. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on May 26 and June 19, 1989, and informally throughout the inspection period, and summarized the scope and findings of the inspection activities.

The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents/processes as proprietary. The licensee acknowledged the findings of the inspection.