U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/90009(DRP); 50-249/90008(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: February 21 through April 2, 1990

Inspectors: S. G. Du Pont
D. E. Hills
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Approved By: J. M. Hinds, Chief
Reactor Projects Section 1B

04-13-90
Date

Inspection Summary

Inspection during the period of February 21 through April 2, 1990 (Report Nos. 50-237/90009(DRP); 50-249/90008(DRP)).
Areas Inspected: Routine unannounced resident and headquarters inspection of previously identified inspection items, licensee event reports (LER), plant operations, maintenance and surveillances, safety assessment/quality verification, previous emergency operating procedure (EOP) inspection items and report review.
Results:

- The non-cited violation described below and various other occurrences indicated that operator performance was mixed. Other occurrences indicating negative performance included control rod mismanipulations described in paragraph 4.b and inadequate knowledge of the operation of a specific throttle valve described in paragraph 5.a.3. The positive side included the excellent response of a licensed operator described in paragraph 4.d which prevented an unplanned scram during a feedwater transient and the identification of a High Pressure Coolant Injection (HPCI) system waterhammer event described in paragraph 4.c.

- A non-cited violation was identified in accordance with 10 CFR 2 Appendix C Section V.A in paragraph 4.a of this report. This involved a failure to correctly follow an outage checklist which resulted in inadvertent recirculation pump seal cavity pressurization. No other violations or deviations were identified.

- A Unit 2 High Pressure Coolant Injection (HPCI) waterhammer event described in paragraph 4.c occurred on March 19, 1990, which was similar to the event reviewed by a November 1-4, 1989 Augmented Inspection Team (AIT).

- The licensee identified a potential analyzed pipe stress condition as described in paragraph 6.

- A follow-up inspection to the previous EOP inspection report 50-237/88012; 50-249/88014 closed all open items from that report except for four items as described in paragraph 8. The inspectors concluded that major improvements had been made in the licensee's EOP program with the development and implementation of revised EOPs based on Revision 4 of the BWR Owners Group emergency procedure guidelines.

DETAILS

1. Persons Contacted

Commonwealth Edison Company

*E. Eenigenburg, Station Manager
*L. Gerner, Technical Superintendent
E. Mantel, Services Director
*J. Kotowski, Production Superintendent
*D. Van Pelt, Assistant Superintendent - Maintenance
J. Achterberg, Assistant Superintendent - Work Planning
*G. Smith, Assistant Superintendent-Operations
*K. Peterman, Regulatory Assurance Supervisor
W. Pietryga, Operating Engineer
M. Korchynsky, Operating Engineer
B. Zank, Operating Engineer
R. Stobert, Operating Engineer
J. Williams, Operating Engineer
M. Strait, Technical Staff Supervisor
L. Johnson, Quality Control Supervisor
J. Mayer, Station Security Administrator
D. Morey, Chemistry Services Supervisor
D. Saccomando, Health Physics Services Supervisor
*K. Kociuba, Quality Assurance Superintendent
S. Stiles, Training Supervisor
T. Lewis, Regulatory Assurance Staff
*G. Bergan, Onsite Nuclear Safety
R. Falbo, Regulatory Assurance Assistant

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 at various times throughout the inspection period.

2. Previously Identified Inspection Items (92701 and 92702)

(Closed) Violation (237/89019-02): Removal of a primary containment isolation fuse was not accomplished in accordance with instructions in that an independent verification did not constitute an adequate component identification. The inspector performed visual observation or reviewed appropriate documentation to verify the following:

- Caution labels were added to the control room panels to indicate that there were two series of fuse labels with similar numbers that were not in sequential order. They further stipulated that all seven digits of the number were to be verified prior to removing a fuse from its holder. The color scheme was also explained.

- Dresden Administrative Procedure (DAP) 7-27, Independent Verification was revised on January 26, 1990, as revision 1 to require fuses that may initiate an Engineering Safety Feature (ESF) actuation to be independently verified and agreed upon prior to removal.

- This event was covered in the operator continuing training program which was completed on March 23, 1990.

- This event was included in tailgate sessions held on December 12, 1989.

This item is considered closed.

(Closed) Open Item (237/88012-04): Verify resolutions to 28 technical deficiencies identified in paragraph 4.B of inspection report 50-237/88012; 50-249/88014. These items were reviewed and closed as described in paragraph 8 of this report.

(Closed) Open Item (237/88012-05): Verify resolutions of walkdown deficiencies identified in paragraph 5 and in attachment B of inspection report 50-237/88012;50-249/88014. These items were reviewed and closed as described in paragraph 8 of this report.

No violations or deviations were identified in this area.

3. Licensee Event Reports Followup (90712 and 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 actions were accomplished, and corrective actions to prevent recurrence had been accomplished in accordance with Technical Specifications.

(Closed) LER 249/90001: Inadvertent Automatic Start of Unit 3 Diesel Generator Due to Procedure Deficiency. This event and corresponding licensee actions were described in inspection report 50-237/90003; 50-249/90003.

No violations or deviations were identified in this area.

4. Plant Operations (71707 and 93702)

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. This included verification that the appropriate number of security personnel were on site; access control barriers were operational; protected areas were well maintained; and vital area barriers were well maintained.

The inspectors verified that the licensee's radiological protection program was implemented in accordance with facility policies and programs and was in compliance with regulatory requirements.

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.

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.

Various operational occurrences were also reviewed as follows:

a. While valving in the seal purge to recirculation pump 3A on February 17, 1990, the equipment attendant found the seal purge valve on recirculation pump 3B open. Unit 3 was shutdown at the time. This resulted in a high pressure in the #1 and #2 seal cavities of 1400 psig and 700 psig, respectively. Although the differential pressures across the seals were within design limits and were therefore of minor safety significance, they were greater than that normally experienced. The seal purge valve to recirculation pump 3B was immediately closed. Further, review indicated that the event occurred as the result of a valving error. A non-licensed operator was clearing several outages in the drywell including outage number III-553, which involved an out-of-service on recirculation pump 3B to repair a seal. The outage checklist specifically indicated that recirculation pump 3B seal purge isolation valve 3-0399-509 was to be left in the closed position when it was cleared. This was to prevent pressurization of the seals since the suction and discharge valves were in the closed position at the time. The seal purge isolation valve was located outside the drywell. Since the copy of the outage checklist became contaminated, the operator left it in the drywell and performed the portion of the clearance involving this valve from memory. As the normal position of this valve when operating was open, the operator placed it in that position resulting in the over-pressurization. This error was discovered prior to the subsequent independent verification.

   The valving error represented a failure to accomplish activities affecting quality in accordance with instructions, in this case the outage checklist, contrary to the requirements of 10 CFR 50 Appendix B Criterion V (50-249/90008-01(DRP)). Review of administrative procedures indicated that no guidance was provided as to whether operators were required to obtain a new copy of the outage checklist and to have it in-hand for completion if it became lost or contaminated. The licensee issued Operations Department Policy

No. 19, Using Outage Checklists, to provide guidance in this area. In addition, the licensee initiated actions to include the event and the subsequent guidance in the operator continuing training program. As the consequence of this isolated event had only minor safety significance and the licensee had initiated appropriate corrective actions, no Notice of Violation is being issued in accordance with 10 CFR 2 Appendix C Section V.A. The inspectors have no other concerns in this area and this item is considered closed.

b. During performance of Dresden Technical Surveillance (DTS) 300-2, Control Rod Drive (CRD) Scram Testing and Scram Valve Timing Test, on February 24, 1990, two rod manipulation errors were performed on Unit 3 by licensed operators. CRD L-9 was pulled from position 40 to position 48 and then scrammed into position 00 in accordance with procedure. However, the CRD was then incorrectly pulled back to position 48 instead of the proper position 40. The Qualified Nuclear Engineer was in attendance to assess the situation and gave guidance to return the CRD to its proper position. The CRD was subsequently placed back to position 40 and testing was continued. Another error occurred approximately 12 minutes later when the wrong CRD was scrammed. The Nuclear Station Operator (NSO) instructed the extra NSO who was stationed behind the main control panel at the scram test panel to scram CRD M-3. The extra NSO misunderstood the NSO and scrammed CRD H-3 instead. CRD H-3 was to have been scram tested later in the testing sequence. The Qualified Nuclear Engineer was again present and CRD H-3 was repositioned to its proper position 48. Scram testing continued and licensee management subsequently suspended further testing about half an hour after the second event to review the policy concerning control rod manipulation errors. Safety significance in regard to core parameters did not exist. A review of procedures controlling testing manipulations of the CRDs revealed that testing of the CRDs was not required to be done in any specific sequence. Additional precautionary measures were taken to increase communication and attention prior to resumption of testing on the next shift. These measures included a discussion between the shift engineer and those involved in the testing to emphasize attention to detail and communication and to ensure that the Qualified Nuclear Engineer indicate to the NSO each time a rod was to be placed back to its proper position. The licensee was still formulating long term corrective actions at the end of the inspection period but items being discussed included emphasis of alpha-designations during communication through tailgates and continuing training programs.

c. On March 19, 1990, a waterhammer event was noted on the Unit 2 HPCI discharge line while performing the valve operability surveillance. Operators reported hearing waterhammer noises as far away as the third floor of the reactor building. (The HPCI discharge piping was beneath the ground floor running through the torus catwalk area, west Low Pressure Coolant Injection (LPCI) corner room and HPCI pump room.) Operators also reported seeing what appeared to be as much as a one inch movement of the piping in the LPCI corner room and vibration being felt on the ground floor. The pump operability portion of the surveillance was suspending pending further licensee

investigation of the event. Some lesser noises were still heard as much as an hour and a half following manipulation of the valves.

A previous event involving the discovery of HPCI support damage on both units was potentially attributed to waterhammer events by an AIT during a November 1-4, 1989 inspection as described in inspection report 50-237/89023; 50-249/89022. Unit 2 HPCI was being kept in an alternate lineup due to steam cuts on a valve seat allowing leakage of feedwater back through outboard discharge valve 2-2301-8. (The bent stem on this valve was replaced during the dual unit outage in December 1989 such that current traces were no longer required each time the valve was cycled.) Unit 3 HPCI valves were repaired during the December 1989/January 1990 refueling outage and therefore Unit 3 HPCI was no longer utilizing the alternate lineup.

The alternate lineup consisted of leaving the valve 2301-8 open and instead closing inboard discharge valve 2301-9. This caused the discharge line to be subjected to feedwater pressure back to valve 2301-9 and Condensate Storage Tank (CST) return valve 2301-10. This higher pressure in this portion of the line prevented saturated conditions. In addition, the stagnated water in the line eventually equalized to the ambient temperature of its surroundings.

The licensee's root cause involved the formation of voids during the HPCI surveillance. The HPCI valve operability surveillance procedure tested the interlock between torus suction valves 2301-35 and 36 and CST return valves 2301-10 and 15. When the torus suction valves opened, the CST return valves automatically closed to prevent pumping the torus water to the CST. The surveillance closed valve 2301-8 and then opened valves 2301-10 and 15. Valves 2301-35 and 36 were then opened and valves 2301-10 and 15 were verified to automatically close. Opening of valves 2301-10 and 15 provided a flowpath, even though valve 2301-8 was closed, since valve 2301-8 still leaked. This allowed feedwater to flow through the system and heat up the water within the piping. Later during inservice testing (IST) timing of valve 2301-9, the waterhammer noise was first heard. Opening of valve 2301-9 had depressurized the volume which by this time was hot enough to result in saturated conditions. When the water reached saturated conditions it flashed to steam to form voids in the piping that could have resulted in waterhammer.

Temperature monitoring did seem to support this root cause. The event occurred at 3:10 a.m. while the temperature taken at the elbow into the X-area (steam tunnel) was 203 degrees F at 9:00 a.m. and 160 degrees F at 2:00 p.m. This indicated that the piping was cooling off from some higher temperature which could represent saturated conditions. Void formation from the higher temperature could have caused the waterhammer.

The original evaluation of the alternate lineup for Unit 2, assigned onsite review number 89-44, addressed needed changes to various procedures including Dresden Operating Surveillance (DOS) 2300-1, HPCI Motor Operated Valve (MOV) Operability Verification, to reflect this lineup. However, the evaluation did not specifically address

the effects of simultaneously opening both CST return valves during the surveillance in light of the known leaking outboard discharge valve.

Detailed walkdowns following this recent occurrence indicated minor damage to two supports which were both located in the torus catwalk area. Support M-1151D-86 was unloaded with a loose clamp nut while support M-1151D-5 was partially unloaded with a bushing pushed out of the clevis. During the previous event, the M-1151D-86 pipe clamp was found slightly skewed and was repaired while no problems were found on support M-1151D-5. Overall, damage was much less extensive than that found during the previous event. No problems were found with the baseplates or anchor bolts. Since the valve operability surveillance was done on a monthly basis, this damage could have also occurred sometime between the previous event and this occurrence. The licensee repaired the damaged supports.

Based upon evaluations done during the previous event for operability of the HPCI system and the lesser damage found during this occurrence, the licensee did not believe the HPCI system to be inoperable due to the two damaged supports.

The licensee revised the valve operability surveillance to close and test only one of the CST return valves at a time such that a potential flowpath would not occur. The licensee then again performed the valve operability procedure on March 22, 1990, while stationing observation personnel in the plant when it was conducted. No waterhammer event was noted. However, about an hour after the valve operability surveillance was complete, licensee personnel found the pipe temperature at the elbow entering the X-area had risen to 322 degrees F while in the alternate lineup. (The temperature at the completion of the surveillance was 91 degrees F.) This increase in temperature indicated that valve 2301-10 was leaking through, providing a flowpath through the system. Saturated conditions were not reached since pressure upstream of valve 2301-10 was at feedwater pressure. Temperatures taken downstream of valve 2301-10 indicated the highest achieved temperature at this point was 140 degrees F which also precluded saturated conditions in this area. After closing valve 2301-15 (located downstream of valve 2301-10) temperature in the line again decreased to equalize with surroundings since this deleted the flowpath. As a result of further testing, the licensee decided to maintain the standby lineup with valve 2301-15 closed to preclude a leakage path. The licensee also intended to change the lineup on Unit 3 the same way, although valve 2301-10 was not currently leaking on that unit, as a precautionary measure. The licensee planned to submit a supplemental LER to the original October 1989 event which would describe additional corrective actions which the licensee was still developing at the end of the inspection period. These actions will be further reviewed when the LER supplement is issued.

d. On March 28, 1990, with Unit 3 at 99 percent rated thermal power, a feedwater transient occurred do to a failure in the feedwater control system. The first indications of the failure were observed

as a demineralizer trouble alarm and an operator selected alarm. The operator selected alarm was set for a reactor water level of 27 inches. The normal low level alarm was 20 inches. Following the alarm, the NSO noticed that feedwater regulating valve A, which was in automatic control, was going closed. Feedwater regulating valve B was in manual control at 40 percent open. The NSO immediately opened feedwater regulating valve B such that the level decrease was turned and then placed valve A in manual and returned water level to a normal 30 inches. Reactor water level had reached a low of 18 inches during the transient as compared to the scram setpoint of eight inches. The NSO then placed the controllers back to their original configuration. Shortly thereafter the red indicating lights on all the feedwater controllers went blank and a feedwater system trouble alarm was received. This time the system automatically switched to the backup control module. The failed control module was subsequently replaced. The licensee with the assistance of the controller vender was investigating the cause of the failure and the late automatic switch to the backup control module. The alert and quick response exhibited by the NSO clearly prevented a scram.

No violations or deviations were identified in this area.

5. Maintenance and Surveillances (62703, 61726, and 93702)

a. Maintenance Activities

Station maintenance activities of systems and components listed below were observed or 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 (LCOs) 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.

(1) Upon rolling the main turbine during the Unit 3 startup on February 20, 1990, condenser vacuum was noted to be decreasing. The licensee found various related problems during the subsequent investigation as described in inspection report 50-237/90003; 50-249/90003. In addition, the licensee

theorized excessive in-leakage into the condenser. Following extensive walkdowns and usage of helium leak detection methods, the licensee placed the main turbine on shell warming. A loud noise was heard under the high pressure turbine cover and upon removal of an inspection hatch, steam was noticed blowing from the top of the turbine. A one inch cap was found missing from a tap that had been used to pour in lubricating oil to enable easier removal of the turbine casing during the recent refueling outage. Work request D83614 had a step to remove the casing but did not specifically address these caps or the process of using lubricating oil to ensure the casing did not stick to the diaphragm. It appeared as if the caps had been reinstalled but were not tightened such that this one vibrated off. There was no safety significance involved in this event and the work package was not safety-related. Therefore, the inspectors have no concerns in this area.

(2) On February 23, 1990, Unit 2 commenced a Technical Specification required shutdown from 90 percent power and declared an Unusual Event. The shutdown was required because of an outboard containment isolation valve failed the valve stroke timing surveillance on the recirculation sample system with the inboard isolation valve leaked past its closed seat. The licensee de-inerted and entered the drywell to repair the inboard valve while the outboard valve's timing was adjusted. On February 24, 1990, all repairs were completed and the Unusual Event was terminated. The inboard valve was left with a very small amount of leakage. The licensee inerted the drywell and returned the reactor to 90 percent power. During the Unusual Event, power was reduced to about 20 percent in preparation for shutdown to Hot Standby. The shutdown was also stopped when the Unusual Event was terminated.

(3) On March 10, 1990, Unit 3 experienced a reactor scram from 100% power. The pilot air line to outboard Main Steam Isolation Valve (MSIV) 2A failed resulting in the closure of the affected MSIV. The pressure spike in turn caused a high flux condition resulting in a reactor scram. High steam flow in the other three main steam lines resulted in closure of all MSIVs (Group I primary containment isolation). The closure of MSIVs (less than 10 percent full open) resulted in another subsequent reactor scram signal. All control rods were verified to be fully inserted. Groups II and III primary containment isolations occurred after the reactor scram due to low vessel water level as expected. Other expected system responses included the reactor building ventilation isolation and standby gas treatment system automatic initiation.

During the event, the operators manually initiated the isolation condenser for vessel pressure control, restored vessel level with the feedwater/condensate system and placed the unit into a safe hot standby condition. The primary containment isolations were reset, with the exception of the affected main steam line.

Several minor component failures did occur during the event. Drywell sample valve 3-8501-58B failed to indicate closed during the Group II isolation but was verified to have closed. A limit switch was adjusted to correct the position indication problem. Isolation condenser condensate return isolation valve 3-1301-3 also failed to manually fully close. This was evident by steam continuing to be released out of the isolation condenser vent after the operator had received a closed indication. Further attempts to close the valve failed and flow was stopped by closure of condensate return valve 3-1301-4, located downstream of this valve. A current trace performed with the valve opening from the as found condition indicated that it had not attained a full closed condition since the representative spike from coming off its seat was not present. Subsequent review indicted that the valve operated as designed. Due to the arrangement of the closed limit switch, the closed indication for this throttle valve may be received before the valve is completely closed. Operating Order 5-90, Operational Guidelines for Motor Operated Valves, issued January 1, 1990, recommended holding the control switch in the closed condition for 20 seconds after the full closed indication is displayed for these type of throttle valves. The operator, in this case, had released the switch as soon as the closed indication was received, preventing it from further closing. Further attempts to close the valve did not work because the valve logic required the valve to be reopened before the closing contactor could be picked up again. This logic was employed as a limitorque anti-hammering modification to address stem bending problems. The licensee was reviewing this operating order to determine if it should be revised to list specifically affected valves. The licensee also planned to provide additional guidance to the operators regarding this logic design.

The pilot air line to MSIV 2A was repaired and the other Unit 3 outboard MSIV pilot air lines were inspected by the licensee. This inspection also resulted in work on the MSIV 2C pilot airline. The licensee attributed failure of the pilot air line to mechanical weakening of the copper tubing at the point where it was coupled to the pilot assembly. It appeared that the tubing had been bent and then straightened which weakened it such that normal vibration caused a failure. Bending of the tubing may have occurred during the recently completed Unit 3 refueling outage when work request D65489, involving rebuilding of the air operator and work request D89891, involving repair of an accumulator air supply check valve were completed. The licensee was evaluating possible corrective actions in regard to a design of the MSIV pilot air lines that would be less susceptible to kinking. The final corrective actions will, therefore, be reviewed in the next inspection period.

Recirculation pump 3A was at first thought to have failed to automatically run back and was manually reduced to minimum speed by the unit operator. It was later determined that the

recirculation pump 3A run back had, in fact, not failed. Recirculation pump 3B had run back without waiting for the designed ten second time delay. Seeing this pump run back, the operator manually ran back the other pump prior to initiation of the automatic run back. The operator was not aware of the designed time delay. A failed time delay relay on pump 3B was subsequently replaced. Failure of this relay has not been a problem in the past. The licensee also planned to provide additional guidance to the operators as to the existence of this relay.

(4) On March 15, 1990, the control room operators observed that recirculation pump 3B seal #2 cavity pressure had trended up to approximately 600 psig as compared to an expected 500 psig. This indicated the existence of some inner seal degredation and leakage. Drywell identified leakage determined from integrator readings when periodically pumping the drywell equipment drain sump indicated about 1.85 gpm which had been relatively constant. Dresden Technical Specifications allow 5 gpm unidentified leakage and 25 gpm total (identified and unidentified) leakage. Thus, leakage was small in comparison to established limits. The licensee increased observation of this area by instituting hourly logging of the seal #2 cavity pressure. As described in inspection report 50-237/90003; 50-249/90003, the licensee had recently shut down Unit 3 to repair leakage from the same seal. Upon overhaul of the seal, the licensee could not find any conclusive evidence of what the problem was. (This seal had been just previously overhauled during the last Unit 3 refueling outage in December 1989). Upon subsequent restart after overhauling the seal, it was noted that the recirculation pump control seal leakoff flow alarm came up when reactor pressure reached 700 psig. However, seal pressures were as expected at that time and thus startup continued. This alarm had been up continually since startup. By March 20, 1990, seal pressure had trended to 660 psig. Following power changes on March 20, 1990, seal pressure was noted to have decreased to about 540 psig. At the end of the inspection period the pressure was 490 psig. The licensee did not conclude that the inadvertent pressurization of the seal cavities in February, as described in paragraph 4.a., contributed to these seal pressure problems. The licensee however, was making contingency plans for possible unit shutdown and repair of the seal.

b. Surveillance Activities

The inspectors observed surveillance testing, including required Technical Specification surveillance testing, and verified for actual activities observed that testing was performed in accordance with adequate procedures. The inspectors also verified that test instrumentation was calibrated, that Limiting Conditions for Operation were met, that removal and restoration of the affected components were accomplished and that test results conformed with Technical Specification and procedure requirements. Additionally, the inspectors ensured that the test results 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 or reviewed portions of the following test activities:

Torus to Drywell Vacuum Breaker Testing
Core Spray Pump Operability Test
LPCI Pump Operability Test
HPCI Valve Operability Test

The inspectors also reviewed the on-site calculational results of corrosion/erosion inspections conducted during the previous Unit 3 refueling outage. These were accomplished in accordance with the program to maintain the integrity of single phase and two phase high energy carbon steel and low alloy steel piping systems against degredation by erosion/corrosion as delineated in Generic Letter 89-08 "Erosion/Corrosion-Induced Pipe Wall Thinning." The program utilized ultrasonic testing techniques to determine component thickness and wear rate and included specific component selection (high probability of excessive wear) and expansion criteria. Sixty-six components were originally chosen for inspection of which four were either repaired or replaced due to inspection results indicating excessive wear. An additional nine components were chosen in accordance with the expansion criteria of which one subsequently needed repair, in accordance with the inspection results. The inspectors believed this to be a useful technique in detecting and preventing possible future failures of piping and related components.

No violations or deviations were identified in this area.

6. Engineering/Technical Support (93702)

The licensee informed the resident inspectors on February 21, 1990 of a potential unanalyzed pipe stress condition which could result with the recirculation system operating in a single loop configuration. The effects of differential expansion with an idle recirculation loop were not explicitly addressed in the original or current design specifications or design/stress reports. Therefore, a temperature differential of more than 50 degrees F between an idle and operating loop would have an unknown effect on pipe stress, support loads, spring can and snubber settings and pipe whip restraint gaps. The licensee believed the effects from a 50 degrees or less temperature differential would be insignificant and acceptable. As the original analysis was completed by General Electric, there existed the potential for generic applicability to other boiling water reactors. Until resolution of this issue, the licensee was implementing temporary administrative controls to ensure that the temperature differential was not allowed to reach 50 degrees F when in single loop operation. The licensee was also reviewing past operating history to identify instances when this potentially unanalyzed condition had been entered and was performing an analysis to determine reportability of this issue based on safety significance. Analyses being performed by the licensee were to address short term operating

considerations of thermal and gravitational stresses for single loop operation for all loops. The licensee had not yet decided whether to do an analysis supporting long term single loop operation for all loops by including seismic concerns. An analysis for long term considerations for loop 3B only was, however, being conducted. These efforts were expected to be completed by mid-April 1990.

No violations or deviations were identified in this area.

7. Safety Assessment/Quality Verification (40500)

Recognizing a negative trend regarding various problems encountered since completion of the Unit 3 outage (as documented in inspection report 50-237/90003; 50-249/90003 and paragraphs 4 and 5 of this report), licensee management conducted a special 50 percent power plateau review. The review, conducted on February 25, 1990, was in accordance with Dresden Policy Statement #24, Achieving and Maintaining Error Free Operation. The various problems discussed included the following:

- Condenser vacuum problems including the partial cause involving the high pressure turbine.
- Recirculation pump seal performance including the consequences of failure of a seal that had just been rebuilt and the current high seal flow alarm.
- Drywell floor and equipment drain leakage.
- Recirculation pump seal cooler failure and temporary modified leakoff piping to the drywell equipment sump.
- Control rod mis-positioning events during scram testing.
- Inadvertent recirculation pump hydro by the CRD system.

As the licensee felt that some of the problems were unnecessary, these problems were subsequently discussed with station personnel during tailgate meetings. The inspectors noted that the licensee review was representative of an ability to recognize and quickly address negative trends.

The inspectors observed the monthly performance review meeting conducted on March 1, 1990. Plant management reviewed items of interest since the last meeting including specific operating events, problems and root cause. The status of various action items was discussed, as well as the 1990 goals presentation and workplace improvement committee items. Recent results of quality assurance audit and surveillances were reviewed and the status of the maintenance improvement program was discussed. The inspectors noted that plant management was well informed and knowledgeable of plant activities.

No violations or deviations were identified in this area.

8. Previous Emergency Operating Procedure (EOP) Inspection Items

An inspection to review the licensee's corrective actions in response to specific deficiencies in the Dresden Emergency Operating Procedures (DEOP) identified in inspection report 50-237/88012; 50-249/88014 was performed. The specific open items reviewed during this inspection were discussed in paragraphs 4.a(1), 4.a(2), 4.a(3), 4.b, 5 and Attachment B to the original inspection report. The inspection was performed in accordance with selected portions of Temporary Instruction (TI) 2515/92. Although the inspection focused on the licensee's corrective actions to open items, considerable effort was devoted to the licensee's recent implementation of revised EOPs based on Revision 4 of the Boiling Water Reactor (BWR) Owners Group Emergency Procedure Guidelines (EPG) and EOP related documentation.

Results

The inspectors concluded that major improvements had been made in the licensee's EOP program with the development and implementation of revised EOPs based on Revision 4 of the BWR Owners Group EPGs. All the open items identified in Sections 4.a(1), 4.a(2), 4.a(3), 4.b, 5 and Attachment B of the original inspection report 50-237/88012; 50-249/88014 have been closed with the exception of four items in Attachment B. The remaining open items are: (1) Item 3, DEOP 200 Series Flow Charts, legibility of scale markings; (2) Item 3, DEOP 500-1, identification of location of proper source of service water; (3) Item 6, DEOP 500-2, proper use of words "to" or "and" in procedures and control room label; and (4) DEOP Equipment Cabinets, development of a procedure to account for equipment stored in cabinets. Specific tracking numbers are assigned in paragraph 8.d of this report. In addition, the inspectors during the course of review of the open items were able to address some of the observations of the original inspection team related to simulator scenarios, human factors analyses and validation and verification.

The inspectors recommend that for the programmatic changes made to the DEOP flow charts and the 500 Series procedures since the original inspection (including deviations from the Plant Specific Technical Guidelines (PSTG)), the licensee should develop and maintain documented justification in auditable form.

a. Objective

The objective of this EOP follow-up inspection was to audit and assess licensee corrective actions in response to items identified in inspection report 50-237/88012; 50-249/88014. In this report, the following areas and number of open items were identified: (1) Technical Adequacy Review of the DEOPs (31); (2) Control Room and Plant Walkdowns and (3) general comments and 60 detailed walkdown comments contained in Attachment B. Three of the open items related to the technical adequacy review of the DEOPs were closed in Inspection Report 50-237/89017; 50-249/89016.

b. Background

The Three Mile Island (TMI) Action Plan (NUREG's 0660, 0737, and 0737, Supplement 1), required licensees of operating reactors to

reanalyze transients and accidents and to upgrade EOPs. Special NRC team inspections of BWR Mark I EOP programs were conducted in 1988; these inspections identified significant weaknesses in some programs, as summarized in NUREG-1358. This follow-up EOP inspection was conducted to confirm that acceptable corrective actions had been implemented at the Dresden Nuclear Power Station, Units 2 and 3, in response to the findings of inspection report 50-237/88012; 50-249/88014, dated August 18, 1988.

Since the initial inspection, two revisions to the DEOP utilizing flow charts (DEOP 100 thru 400) had been made. The first revision issued in October 1988 primarily corrected deficiencies resulting from the inspection. The second revision which was implemented in December 1989 was based on Revision 4 to the BWR Owners Group EPGs. This revision also made significant format changes to the procedures. The inspectors reviewed the first revision to flow charts to determine which findings of the inspection report were addressed and the latest revision to assure these findings were included and if any of the findings not addressed in the first revision where corrected in the most current revision. Many of the more general findings, and in particular those related to human factor observations, were improved in the current revision to the DEOPs. The 500 Series DEOPs which were in written format, were extensively revised once since the initial inspection in December 1989.

c. Findings

The findings identified in inspection report 50-237/88012; 50-249/88014 are addressed in this Section. Numbers in parenthesis indicate section and item in the original inspection report. Validation of the drywell spray initiation pressure limit (4.a.1), justification for use of 200 degrees as an entry condition for primary containment high temperature (4.a.2), and validation of the nomograph showing allowable pump net positive suction head (4.a.3) were closed in inspection report 50-237/89017; 50-249/89016. Since this inspection, two EOP revisions (October 1988 and December 1989) had occurred. The inspection open items identified were addressed in the October 1988 DEOP revision as indicated in the licensee's September 30, 1988 response which identified corrective actions being taken. The inspectors also verified that all the applicable open item revisions in the October 1988 DEOP revision were retained in the December 1989 DEOP revision which utilized Revision 4 to the BWR Owners Group EPGs.

<u>Independent Technical Adequacy Review of the EOPs</u>

(1) (Closed) Open Item (237/88012-4.b.1 and 249/88014-4.b.1): Difference between the PSTG caution and DEOP caution related to conditions under which Reactor Pressure Vessel (RPV) may be depressurized. The revised DEOP 100 eliminated ambiguity by not requiring a determination if adequate flow was available to cool the core. The flow chart identified the systems and number of systems required to be operable to maintain core cooling. This item is closed.

(2) (Closed) Open Item 237/88012-4.b.2 and 249/88014-4.b.2): PSTG step SP/T-4 had missing information. The licensee's September 30, 1988 letter stated the information was inadvertently omitted and that the PSTG would be revised as part of the Revision 4 upgrade to the EPGs. The inspectors reviewed the current PSTG and determined the missing information was included. This item is closed.

(3) (Closed) Open Item (237/88012-4.b.3 and 249/88014-4.b.3): PSTG Caution 21 does not apply to the HPCI. This caution was deleted in the revised DEOP. This item is closed.

(4) (Closed) Open Item 237/88012-4.b.4 and 24/88014-4.b.4): DEOP Flow Chart 200-4 procedure executes Reactor Vessel Control (RVC) at Step C4A1 whereas the PSTG executes this step after emergency depressurization. The PSTG had been revised to match the flow logic in the DEOP. This item is closed.

(5) (Closed) Open Item (237/88012-4.b.5 and 249/88014-4.b.5): An inconsistency was identified between DEOP Flow Chart 200-4, Caution 9 and control room label relative to number of gallons of water in the condensate storage tank when it reaches low level of 1.5 ft. The reference to gallons in the flow chart had been eliminated. The flow chart was currently consistent with the control room label and only indicates a low level of 1.5 ft. This item is closed.

(6) (Closed) Open Item (237/88012-4.b.6 and 249/88014-4.b.6): DEOP 200-1, Step C2B calls for operation of drywell coolers which is not in the PSTG. Drywell coolers had been eliminated in DEOP 200-1. This item is closed.

(7) (Closed) Open Item (237/88012-4.b.7 and 249/88014-4.b.7): DEOP 200-2, Step C2 for bypassing interlocks prior to starting drywell coolers is not in the PSTG, nor is the drywell pressure requirement of less than 5 psig for operation of these coolers. The licensee in its September 30, 1988 letter stated the authorization to bypass interlocks, if necessary, to operate the drywell coolers had been incorporated into Revision 4 of the EPG. Since this revision to the EPGs was currently in use at Dresden, this is acceptable and this item is closed.

The licensee also justified the 5 psig drywell limit in the September 30, 1988 letter. The licensee stated that this limit was consistent with the operating limit imposed in the drywell cooler system operating procedure and that operation at higher pressures may cause the fan motors to overheat. The inspectors determined this justification is acceptable and therefore this item is closed.

(8) (Closed) Open Item (237/88012-4.b.8 and 249/88014-4.b.8): In DEOP 200-1 the first override differs from the associated override in the PSTGs, torus "cooling" is not contained in the PSTGs, and drywell spray is not contained in the PSTGS. The

differences between the first override in the DEOP and PSTGs had been corrected and torus "cooling" had been eliminated from the DEOP. The licensee in its September 30, 1988 letter stated that the current placement of the instruction to close the drywell spray valves was consistent with the basic intent of the PSTGs and therefore no change to DEOP 200-1 was required. The inspectors reviewed the DEOP flow chart and agreed with the licensee's determination. This item is closed.

(9) (Closed) Open Item (237/88012-4.b.9 and 249/88014-4.b.9): In DEOP 200-1 the drywell pressure value of 14 psig in the flow chart was different from the step in the PSTG which called for 13.4 psig in the torus. This value was rounded off to 13 psig in the October 1988 revision to DEOP 200-1 for instrumentation readability which was in the conservative direction. The new PSTG (based on Revision 4 to the BWR Owners Group EOPs) utilized a new calculational method and resulted in the use of a 9 psig drywell pressure in DEOP 200-1. This item is closed.

(10) (Closed) Open Item (237/88012-4.b.10 and 249/88014-4.b.10): In DEOP 200-1 the PSTG Step PC/P-7 "or if the suppression chamber cannot be vented" has not been incorporated in the DEOP flow chart. A step had been added to the flow chart that states the drywell should be vented if the suppression chamber cannot be vented. This item is closed.

(11) (Closed) Open Item (237/88012-4.b.11 and 249/88014-4.b.11): In DEOP 300 the integrated radiation release control actions and secondary containment control actions are different than the PSTG. These actions had been corrected to be consistent with the PSTG. This item is closed.

(12) (Closed) Open Item (237/88012-4.b.12 and 249/88014-4.b.12): In DEOP 100, Step 4 the last item is not contained in the PSTG. DEOP 100 and the PSTG had been made consistent. This item is closed.

(13) (Closed) Open Item (237/88012-4.b.13 and 249/88014-4.b.13): In DEOP 100 the logic of control and insertion differs from the PSTG steps. The licensee in its September 30, 1988 letter stated that the various actions to insert control rods was consistent with that incorporated in Revision 4 to the EPGs. The inspectors verified that the PSTG and DEOP 100 were consistent with EOP Revision 4. This item is closed.

(14) (Closed) Open Item (237/88012-4.b.14 and 249/88014-4.b.14): In DEOP 100 step RC/L-2 was reversed in sequence relative to PSTG. The licensee in its September 30, 1988 letter stated this was corrected and the inspectors verified that the sequence of these steps was consistent between the DEOP and PSTG. This item is closed.

(15) (Closed) Open Item (237/88012-4.b.15 and 249/88014-4.b.15): In DEOP 100 the words "AND CONTROL" were omitted from steps RC/L,P,Q. The licensee in its September 30, 1988 letter stated this was corrected and this was verified during the inspection. This item is closed.

(16) (Closed) Open Item (237/88012-4.b.16 and 249/88014-4.b.16): In DEOP 100 cautions identified as applicable to step RC/P-5 differ from the PSTG. The inspectors verified that the cautions in the DEOP were consistent with the PSTG. This item is closed.

(17) (Closed) Open Item (237/88012-4.b.17 and 249/88014-4.b.17): In DEOP 100 step RC/RC2b and 2c are functionally different from the PSTG. Inspectors verified that these steps were currently consistent between the DEOP and PSTG. This item is closed.

(18) (Closed) Open Item (237/88012-4.b.18 and 249/88014-4.b.18): In DEOP 400-1 the procedural override preceding Step 1 does not appear in the PSTG. The inspectors verified that this procedural override had been eliminated. This item is closed.

(19) (Closed) Open Item (237/88012-4.b.19 and 249/88014-4.b.19): In DEOP 400-1 the LPCI subsystem identifiers in the PSTG and DEOPS are different. The inspectors verified that the LPCI subsystem identifiers in the DEOP were consistent with the PSTG. This item is closed.

(20) (Closed) Open Item (237/88012-4.b.20 and 249/88014-4.b.20): In DEOP 400-1 logic step C12C is not consistent with the intent of the PSTG. The inspectors verified that the flow charts had been revised to be consistent with the intent of the PSTG. When the RPV level drops below minus 143 inches emergency depressurization was required and if no injection system was available the flow charts directed the operators to go into the steam cooling mode. This item is closed.

(21) (Closed) Open Item (237/88012-4.b.21 and 249/88014-4.b.21): In DEOP 400-2 the logic of steam cooling differs from the PSTG. The inspectors verified that the DEOP had been revised to be consistent with the PSTG. This item is closed.

(22) (Closed) Open Item (237/88012-4.b.22 and 249/88014-4.b.22): In DEOP 400-2, Step C6 and the preceding decision were not contained in the PSTG. The inspectors verified that these items were eliminated from the revised DEOP to be consistent with the PSTG. This item is closed.

(23) (Closed) Open Item (237/88012-4.b.23 and 249/88014-4.b.23): In DEOP 400-2 the head vent as a method of RPV depressurization is not identified, however, it is identified in the PSTG. The inspectors verified it had been identified as a method of RPV depressurization in the revised DEOP. This item is closed.

(24) (Closed) Open Item (237/88012-4.b.24 and 249/88014-4.b.24): In DEOP 400-3 logic step C4 does not meet the intent of the PSTG. This had been revised to be consistent with the PSTG. This item is closed.

(25) (Closed) Open Item (237/88012-4.b.25 and 249/88014-4.b.25): DEOP 400-3 references the primary containment design pressure and the PSTG references the suppression chamber pressure. The licensee had installed a torus bottom pressure indication, therefore, the drywell and suppression chamber pressures were no longer utilized in this flow chart. This item is closed.

(26) (Closed) Open Item (237/88012-4.b.26 and 249/88014-4.b.26): In DEOP 400-3, Step 12 mis-references Step 18. The PSTG references Step 17. Steps 17 and 18 were also improperly referenced in the original inspection report. However this comment was no longer valid since these steps had been eliminated in the December 1989 revision to DEOP 400-3 which referenced DEOP 400-5 (failure to scram procedure). This item is closed.

(27) (Closed) Open Item (237/88012-4.b.27 and 249/88014-4.b.27): In DEOP 400-4, Step 8 is not contained in the PSTG. The inspectors verified that Step 8 had been eliminated from DEOP 400-4. This item is closed.

(28) (Closed) Open Item (237/88012-4.b.28 and 249/88014-4.b.28): The original inspection report identified procedures that may have to be executed concurrently with the DEOPs. The inspection team specifically concluded that Alarm Response and Abnormal Operating Procedures contained instructional steps that differed from the DEOPs. In the licensees September 30, 1988 response, it was stated that DAP 9-13, Procedural Response to Abnormal Conditions, established hierarchy of procedure categories to follow during abnormal procedures. This procedure identifies DEOPs as the highest priority, followed by Dresden General Abnormals, Dresden Operating Abnormals and Annunciator Procedures. In addition, the Dresden Stations upgrading of operating procedures was currently ongoing. The licensee during this inspection stated that any discrepancies that existed should be eliminated when this upgrade is completed. Based on the establishment of a hierarchy and the revision of procedures currently ongoing, the inspectors have determined this concern is resolved and this item is closed.

Closure of these 28 items constitutes total closure of items 237/80012-04 and 249/80014-04 in the original inspection report.

Control Room and Plant Walkdowns

(Closed) Open Item (237/88012-5a and 249/88014-5a): During the original inspection it was noted that the values specified in the

flow chart DEOPs frequently require a level of accuracy which is not obtainable from the instruments used by the operators. In this follow-up inspection the values specified in the December 1989 revision to the flow charts, which was based on Revision 4 of the BWR Owners Group EPGs, were checked against the PSTG and the flow charts that were in effect during the original inspection. Based on this review it was determined that this concern had been adequately addressed. Numbers had been rounded off to values that match instrument accuracy and were in a conservative direction. This inspection also addressed the walkdown comments many of which were related to this concern. The results of the walkdown review, which are discussed later, provide further verification this concern had been adequately addressed. Based on these findings this item is closed.

(Closed) Open Item (237/88012-5b and 249/88014-5b): In the original inspection, inconsistencies between equipment labeling and procedures were noted in addition to missing and mis-marked labels: Attachment B to the original inspection report identified specific examples of these problems. During this follow-up inspection, the inspectors addressed all of the walkdown concerns. Except for a few items, all the inconsistencies and labeling problems had been corrected. Almost all the Detailed Control Room Design Review (DCRDR) modifications had been completed and new labels had been installed on the panels. The DEOP coordinator for Dresden, stated that during DCRDR modifications, valve labeling, and the DEOP flow chart modifications, a considerable effort went into correcting these problems. The inspectors did not check beyond those items identified during the walkdown to determine the extent to which inconsistencies had been corrected. However, based on the findings resulting from the follow-up inspection of the walkdown items, the extensive DCRDR modifications, valve labeling and the procedure upgrade program, it could be concluded that most of the concerns identified had been corrected. This item is closed.

(Closed) Open Item (237/88012-5c and 249/88014-5c): During the original inspection, many specific examples of deficiencies discovered during the walkdowns were identified in Attachment B to the inspection reports, which raised concerns related to the adequacy of the process used at Dresden to develop and implement the DEOPs. These Attachment B deficiencies were reviewed during the follow-up inspection and are discussed below.

<u>DEOP 200 Series Flow Charts, Walkdown Comments</u>

(1) The medium range Drywell pressure gage, 8540-001, used to detect any entry condition into Containment Pressure Control, had dymo label markings for the proper scale on the cover of a 0 to 100 gage scale. A new scale had been put on the recorder. This item is closed.

(2) The "cooling valves" in Procedure Section 200-1, in the block between location Points 2 and 3 are actually labeled "Flow Test" (2-1051-38B and 2-1501-20B) on the panel. Reference to

"cooling valves" had been eliminated from the flow chart Section 200-1. This item is closed.

(3) The medium range drywell pressure strip chart indicator is covered with ink to the point of illegibility and the position indications on the panel drywell spray valve operating switch are also illegible. Problems with the pressure strip chart still existed. Although it was still legible, the markings in some areas of the scale were almost illegible from clearing to remove ink. No problem with the position indications on the panel spray valve operating switch appeared to exist. This item is open.

(4) The nomenclature "Suppression Pool" and "Torus" are used interchangeably in panel labels, sometimes on the same instruments, such as back panel Recorders 2-1640-200A and B for torus water temperature. The flow chart procedure seems to consistently use "Torus." As a result of control room panel modifications, all nomenclature had been changed to "torus" which matches procedures. This item is closed.

(5) In the step following Block 4A of the torus temperature (200-3) procedure, torus water temperature is to be maintained below 156 degrees. The temperature indicator is calibrated in 5 degree increments and, therefore, can not be read to this level of precision. Reference to this temperature was eliminated in the December 1989 revision to the DEOP 200 flow chart and replaced by a heat capacity temperature limit curve. This item is closed.

(6) There were instances of inconsistency in the application of magenta DEOP indicator tags on instruments referenced in the DEOPs. Examples where tags were missing were torus cooling and the acoustic monitors (which are also not labeled as to function). Tags were remarked during the control room upgrade which was associated with the DCRDR and inconsistencies or missing tags no longer existed. Also a black line border had been placed around tags referenced in the DEOPs. This item is closed.

(7) In the cautions and notes, No. 21 caution that elevated torus pressure may trip the HPCI turbine on high turbine exhaust pressure. The gage, PI 2340-5, is not marked for this trip point (100 psig). No. 28 notes that only drywell pressure wide range indicators should be utilized for containment pressures above 5 psig, and specifies that indicators PI-2(3)1640-11A/B on Panel 902(3)-3 be used. These indicators are marked LT-1641-5A and B. These cautions and notes had been deleted. This item is closed.

<u>DEOP 100, Reactor Control</u>

(1) The inconsistent use of magenta labeling was noted during the walkdown of DEOP 100. For example, two of the four entry

conditions (RPV pressure and power) had meters that were not identified with magenta labels in the control room. Also, the DEOP equipment cabinets were identified with white labels. The use of colored labels was described in DAP 9-4, Control of Dresden Emergency Operating Procedures. DAP 9-4, which was revised in January 1989, no longer requires the use of colored labels. This item is closed.

(2) The meter, 1602-1, Torus Pressure, was observed not to have any engineering units on the meter scale. Engineering units had been placed on the meter scale. This item is closed.

(3) The scram test switches (Step 6C3) do not have the switch positions labelled on Panel 902-16. The scram test switch positions had been labelled on the panel. This item is closed.

(4) Step 100-1.4 states, "Maintain RPV level greater than -143 inches." The meter that is used to measure -143 inches has a range of +60 to -340 inches in increments of 10 inches. A value of -143 inches can only be estimated. The typographical error had been corrected and a mark had been placed in the meter indicating the -143 inch level. This item is closed.

(5) Step 3 states, "Verify Aux Power has transferred." The operators know how to perform this step using common knowledge, but the control room panels and breaker switches are not labelled "Aux Power." This step had been eliminated from the DEOP. This item is closed.

(6) Caution 9 refers to a Condensate Storage Tank Level of "1.5 ft. or 10,000 gals." The meter is located in Unit 2 only (not in Unit 3, as implied by the wording of the caution) and has increments in feet of water level. A label next to the meter stated each foot of water level was equal to 8,000 gallons. Therefore, 1.5 feet is equal to 12,000 gallons, not 10,000 gallons. In the same caution, HPCI was incorrectly called HPIC, and the word "torus" was used when the control room labels call the torus a "suppression pool." The procedure had removed the reference to gallons. The typographical error had been corrected and control room labeling had been corrected to read "Torus" as previously noted. This item is closed.

(7) Caution 19 stated, "Manually trip Standby Liquid Control (SLC) pumps at 0% level in the SLC tank." Since the pumps do not automatically trip on low level in the tank, waiting to stop the pumps at 0% can result in pump damage due to loss of pump suction. DEOP 400-5 had been revised to trip pump when SLC tank level drops to 8%. This item is closed.

DEOP 200 Series Flow Charts, Secondary Containment and Radioactive Release Control

(1) The Reactor Building Exhaust entry condition (greater than 4 mr/hr) is actually called a "Vent" on the meter. It has no magenta EOP tag, and no indication of the alarm point (on either Unit 2 or Unit 3). The words "Exhaust Duct" had been added to meter. This tag had been changed and had a black line border indicating it was referenced in the DEOPs. The alarm point was no longer specified in the DEOP. This item is closed.

(2) The determination as to whether an area temperature entry condition has been reached (greater than "max normal") is somewhat complex. A front panel alarm is received which directs the operator to a back panel on which the individual locations which feed the front panel are indicated. Those which are DEOP entry conditions are marked with the magenta DEOP label on this back panel. In all but 4 cases, this would immediately alert the operator that an entry condition had been reached. To determine if an entry condition had been reached in the X-Area or Shutdown Cooling Area, the operator must press a button and read a meter. The X-Area and Shutdown Cooling Area were alarmed on the front panel. It appeared the nomenclature identifying these areas may have been misleading to the inspectors during the original inspection. This comment is not valid and therefore this item is closed.

DEOP 400-1, Level Restoration

(1) The Automatic Depressurization System (ADS) system was called "Automatic Blowdown System" (ABS) on the control panel name plate. This had been changed. This item is closed.

(2) The table located under Step 3 of the flow chart procedure directs actions based on whether the RPV is a "Low Pressure," "Intermediate Pressure" or "High Pressure." The Low Pressure and the Intermediate Pressure regimes are separated by a bar labeled 80 psig and the Intermediate Pressure and High Pressure regimes by a bar labeled 330 psig. If the RPV pressures were exactly at 80 or 330 psig, the operator would be uncertain as to the correct action to take in accordance with this table. In the center section (Intermediate Pressure section), the entry question is "is HPCI available." In the steps that follow this question, there is no step which directs the use of HPCI. The December 1989 revision to this DEOP had eliminated this problem. Actions were based on the RPV pressure being greater than 50 psi above the drywell pressure (single pressure value) and a subsequent step which directed the operator to rapidly depressurize the RPV. This item is closed.

(3) Several steps in this procedure require that RPV level be read at -143 in. The gage has gradations in 10 inch increments and cannot be read to this level of accuracy. Similarly, RPV

pressure is to be read at 1101 psig. This gage has increments of 20 psig. A mark had been placed on the gage indicating the -143 in. RPV level. The step that required the operator to read a RPV pressure of 1101 psig had been revised to eliminate this pressure. The procedure currently stated that if depressurization were required, that the RPV should be blown down. This item is closed.

(4) This flow chart procedure has the same procedures as previously noted regarding values which cannot be read to the accuracy it specifies. All values had been changed to readable values or eliminated. This item is closed.

(5) In Block 1, the word "opening" should be changed to "cycling." The use of the word "opening" had been eliminated in the revised flow charts. This item is closed.

DEOP 400-2, Emergency Pressurization

(1) In Block 1 the word "expect" should be changed to "except." This had been changed in subsequent revisions. This item is closed.

(2) This procedure, in several places, calls for "torus pressure" to be read and compared with RPV pressure. The torus pressure gage can only be read from +5 to -2.45 in. and so cannot be used in all cases to make this comparison. It is believed that the operators actually use Drywell Pressure when making these comparisons. The narrow range of this pressure gage also makes it impossible for the torus pressure to be compared with primary containment design pressure as called for in Note 29 of the procedure. This problem had been eliminated with the use of the newly installed torus bottom pressure indication instead of the torus pressure gage. This item is closed.

(3) The torus pressure gage on Unit 3 does not indicate the units of measurement. It should read PSIG. The scale also consists of dymo labels applied over a scale which is graduated 0 to 100. This problem had also been eliminated by the use of the newly installed torus bottom pressure indication instead of torus pressure. This item is closed.

DEOP 400-3, RPV Flooding

(1) This flow chart procedure has the same problems as previously noted regarding values which cannot be read to the accuracy it specifies. The procedures had been revised to correct this problem. This item is closed.

(2) Caution 25 is repeated in the block which directs the operator to the caution. The December 1989 revision had eliminated this redundancy. This item is closed.

DEOP 500-1, Alternate Standby Liquid Control Injection

(1) The inspector checked the access to and availability of boron to the plant in the event alternate boron injection is required. Security was asked to provide a key to the storeroom where the chemicals are stored. The security personnel on duty could not identify the proper key which was ultimately obtained from storeroom personnel. Adequate boric acid (10, 325# barrels) and borax (8, 320# barrels) were located. However, these were found to be surrounded by heavy pallets of absorbent granules which would need to be moved out of the way before the boron could be taken to the Turbine Building. There was no equipment in the storeroom which could be used to move either the boron or the blocking pallets. Storeroom personnel stated that it is planned to bring fork lifts from the main storeroom. Qualification and availability of personnel to perform this function on the back shifts and weekends should be verified by the licensee.

The licensee in its September 30, 1988 response stated that Dresden is providing a controlled storage space for boron chemicals that would be established by December 1, 1988. The licensee had since changed its method of storage of boron. The boron was currently contained in premeasured 3.5 gallon containers which were stored in a dedicated locked cage within the Unit 2 turbine building. The licensee during its verification and validation program verified that adequate personnel were available to perform this function on the back shifts and weekends. This item is closed.

(2) Steps 4.b.(1), (2), and (3) call for the manipulation of valves in the Reactor Water Cleanup (RWCU) Demineralizer Valve Gallery. This is a high radiation area. The valves are located high in the gallery and there is no ladder or other equipment provided to facilitate their operation in an emergency. The DEOP no longer required manipulation of these valves since the condensate demineralizers were used instead of the RWCU demineralizers for alternate SLC injection. This item is closed.

(3) Several problems were noted in carrying out Steps 5.a.(12)(a) through (c) which are the steps in which alternative sources of water are obtained to prepare a boron solution in the CATEX tank. Step (a): Neither of the clean demin. water source valves or supply fittings were marked. The supply located on the east end of U2 Turbine Building Closed Cooling Water (TBCCW) Heat Exchanger has two stop valves. The upstream valve is missing a valve handle and it is unknown if the valve is open or shut. Step (b): There are several Condensate Demineralizer Post Strainer Drains, so the items should be made plural in the procedure. Step (c): The proper source of Service Water for this evaluation was not easily determined. After some searching, it was determined that a pressure test connection which now has a gage attached would be the most

likely candidate source. All of the problems identified had been corrected with the exception of the location of the proper source of service water. This location was not the pressure test connection identified in the original report. The inspectors recommend that the true location be identified in the procedure. The original inspection report also recommended that the alternate sources of water should have magenta tags indicating these are identified in the DEOPs. The licensee stated that no special DEOP designation had been given to any systems for ease of finding including those that provide alternate sources of water for the SLC system. Since Dresden had not specifically identified these as DEOP systems to maintain marking consistency throughout the plant, the inspectors have no objection to the licensee's position. This item is closed except for the concern related to identification of the location of the proper source of service water.

(4) In Step 9.b.(1)(a) and (d) the Cleanup Controller and the Drain Flow Regulator were without numbers in the Control Room (this is one example of many). In Step (e), RWCU system temperature is obtained from a six position temperature instrument. The procedure does not specify which position should be used (probably Position 3). In Step (i), the operator is to observe Regenerative Heat Exchanger Inlet Pressure and Reactor Pressure and note when the difference is less than 100 psig. The procedure does not direct the operator to the nearest Reactor Pressure gage to minimize the difficulty of making this calculation (probably the HPCI pressure gage). In Step (n), the operator is to "maintain suction pressure on RWCU Recirculation Pumps" however no values are given. Since the RWCU system was no longer used as an alternate source of water for standby liquid control injection these concerns are no longer valid. This item is closed.

<u>DEOP 500-2, Bypassing Interlocks and Isolations</u>

(1) In Procedure DEOP 500-2, some minor inconsistencies were noted between switch labelling in the control room and valve descriptions in the procedure. This was corrected with the December 1989 revision. This item is closed.

(2) In Step A.8, Step C.1 should be E.1. This step had been eliminated in the revised procedure. This item is closed.

(3) In Step C.1.c(7), Valve MO 3-3005 was noted not to be numbered on the control room label, only the name of the valve was given. This had been corrected as part of the control room upgrade. This item is closed.

(4) Three main steamline drain valves, MO 3-220-1, 220-3 and 220-4 were observed to have control switch positions (open-closed) that could not be read, because the labelling had worn off. These valves had been relabeled. This item is closed.

(5) Step C.1.c(18) instructs operators to "Return the Main Steam Line (MSL) drain valves to their normal position." The step should clearly list which valves are to be returned to their normal position. This had not been changed in the revised procedure. The valves in question were identified as required to be verified "open" four steps earlier in the procedure in the same page. Although it was not necessary to relist these valves, the inspectors suggest relisting for consistency. This item is closed.

(6) In Step C.2.b, the words "to" are indicated as "and" in the control room labels. This has not been changed in the control room. Upon further review by the inspectors, it was determined that the 4kv breakers can go either way. Therefore "and" as indicated in the control room label was more appropriate and the procedure should be changed. This item is open.

(7) In Step C.3.a(1)(f), the operator is supposed to perform an action based on reactor water level being below 2/3 core height. This level in inches is more appropriate in the procedure and should be consistent with the ability to read the Fuel Zone range meters. This had been changed. This item is closed.

(8) Step C.3.a(1)(k) references a dP indicating controller that the operator has to monitor. The scale on the meter was noted to be incorrect. The correct scale was superimposed onto the incorrect scale with a piece of tape. This had been corrected. This item is closed.

(9) Step C.4.a(2) directs operators to ensure the Fuel Pool radiation level is below 100 mr/hr. The control room meter was labelled with an alarm setpoint of 90 mr/hr. The difference between the 90 and 100 mr/hr setpoint was not clear. Since the control room meter had an alarm setpoint which is lower than specified in the procedure and was therefore more conservative, this is acceptable. This item is closed.

(10) Step C.4.a(4) should include the value needed for the operator to determine if Reactor Building differential pressure is being maintained. This step had been deleted for the procedure. This item is closed.

(11) Step C.4.b(3)(a) and (b) direct the operator to start fans without clearly identifying which fans are to be started. Since there were only two fans (fan types designated as RBX exhaust and supply fans) which were clearly marked, the inspectors do not think it is necessary to identify the specific fans by number in the procedure. This item is closed.

(12) Step C.6 incorrectly lists "RFP" as "RVP". Also, the last two steps, D and E, are incorrectly labelled as G and H. The procedure had been revised to correct these problems. This item is closed.

DEOP 500-3, Alternate Water Injection Systems

(1) Step D.1.b.(6) requires the operator to pump the alternate unit's torus to the unit in distress hotwell per DOP 1600-2 (Torus Water Level Control). DOP 1600-2 does not contain a section or other direction to accomplish the required action. The procedure had been revised to be a stand alone procedure (no longer references DOP 1600-2). This item is closed.

(2) Step 2.a.(3)(a) and (b) should be reversed. Presently the control room valves are opened first and then the remotely operated valves. The procedure had been revised to correct this problem. This item is closed.

(3) Step 3.b.(7) the CRD cooling water flow is not numbered in Unit 2. This had been numbered in the control room as part of the upgrade. This item is closed.

(4) Step 3.d.(8) requires the comparison of Pump A and B discharge header pressures at the local control station, and throttle the lower pressure pump until the pumps are at approximately the same pressure. These gages are widely separated and cannot be used in the required manner. The procedure had been changed. The CRD pumps were currently balanced using the pump amperage indicators in the control room. This item is closed.

(5) Step 9.b.(12)(b) the breaker for MO 205-2-4 is labeled incorrectly on the breaker (now reads MO 205-24). This problem had been corrected for both units with new labels. However, the old blue label on Unit 3 had not been removed. This item is closed.

DEOP 500-4, Containment Venting

(1) In procedure Step A.1, the licensee should change Step 2.a to 2 and change Step C.1 to D.1. In procedure Step A.2, change Step 8 to 8A or 8B and change Step C.2 to D.2. In Procedure Step B.2, change Step C.1 to D.1 and change C.2 to D.2. In all cases, the wrong step numbers were noted to be used in Procedure 500-4. Entry and exit conditions had been eliminated in the revised procedures. This comment is no longer applicable. This item is closed.

(2) Step D.1.a.(6) instructs the operator to reset the drywell isolation. The step should instruct the operator to place the switch in both the left and right positions, to agree with instructions given in Step D.2.c(1). This step had been eliminated in the latest revision of the procedure. This item is closed.

(3) Step D.1.b(3) tells the operator to monitor Standby Gas Treatment (SBGT) area radiation monitors. The SBGT area radiation monitor is displayed only on Unit 3, and is not identified with a maroon colored DEOP label. The label for this radiation monitor currently had a DEOP designation. This item is closed.

(4) Step D.2.b instructs operators to verify SBGT is operating. The step implies SBGT is already in service. Instructions for starting SBGT should be added to the step. Starting of the SGTS only required the turning of a switch in the control room. Therefore, specific instructions were not required. This item is closed.

(5) Steps D.2.c(1) and (2) instruct operators to reset the drywell isolation. A review of the electrical schematic diagrams indicates the drywell isolation reset is not required to open the 2" vent relief valves. The procedure had been revised to correct this error. This item is closed.

(6) Step D.2.e provides directions to install jumpers utilizing open ended connections that require additional nuts. The use of alligator clips would allow jumpers to be installed quicker and easier, but is not administratively allowed at Dresden. Dresden procedures still did not permit the use of alligator clips. Therefore this recommendations was not applicable. This item is closed.

(7) Step D.2.g(5) incorrectly underlines the word CLOSE. The procedure had been revised to correct this error. This item is closed.

(8) Valves used the performance of DEOP 500-4 were inspected in the field. Some valves were not clearly identified. Additionally, most valves are located in high radiation or contaminated areas. This could hinder operator actions if portable air or nitrogen bottles were required to be connected to certain valves on loss of normal air supplies. All safety related valves had been retagged as a result of a station wide effort. Work was also currently in progress to retag balance of plant (BOP) valves. This effort was to be completed in 1991. When this retagging is completed, all concerns related to valves not being clearly or properly identified should be eliminated. This item is closed.

DEOP Equipment Storage Cabinets

(1) The contents of the two equipment storage cabinets are inspected. The cabinet located in the control room contained: two sound powered headphones; miscellaneous jumpers of different lengths; tools to install jumpers, lift leads or pull fuses; insulated gloves; and fire hose fittings to connect fire protection water to the feed pump suction (alternate water injection).

(2) The cabinet located in the Turbine Building contained: several sound powered headphones; hoses for alternate SLC injection (DEOP 500-1) and venting the over piston area of CRD's (DEOP 100, Step 6E); tools for connecting the hoses and venting the over piston area; hose fittings; and copies of Procedure 500-1.

The contents of the cabinets are supposed to be inspected on a quarterly basis, per Procedure DOS-10-15, which is currently in the draft process. The licensee had stated that Procedure DOS-10-15 was still in draft and had therefore not been issued. To assure this equipment remains available in the specified equipment cabinets, these two items will remain open until this procedure is completed. This item is open.

DOP 1600-2, Torus Water Level Control Procedure, A Reference Procedure In DEOP-200

(1) In Step F.2.c.(1) the procedure specified Torus Transfer Isolation Valves are labeled Torus/Hotwell Isolation Valve on the Panel (2(3)-1599-61 and -62).

(2) In Step F.2.h. the procedure calls for hotwell water level to be read on LI 1602-3 on Panel 902(3)-3. The specified indicator is actually the torus level indicator. The proper indicator is 2-3340-06 on Panel 902(3)-7.

(3) In Step F.3.c., the HPCI Flow Bypass Valve MO-2301-14 is actually labeled Minimum Flow Valve on the panel and is not a throttle valve as the procedure indicates.

(4) In Attachment A to this procedure, the vertical axis is not labeled other than at the top with "PSIG." The vertical axis should be labeled "Torus/Drywell Differential Pressure, PSID." Reference to this procedure was eliminated in the December 1989 revision to DEOP 200. Therefore these concerns are no longer applicable. These items are closed.

DOA 250-1, Relief Valve Failure (A Referenced Procedure in DEOP 200)

In Step D.2.d. the Motor Suction Pump is actually labeled Turbine Main Shaft Suction Pump on the panel. This procedure was no longer utilized. This item is closed.

Based on the above findings, all but four open items in inspection report 50-237/88012; 50-249/88014 are closed.

Simulator Scenarios (Section 6 of the Original Inspection Report)

In the original inspection report, several specific concerns were identified as a result of the simulator scenarios performed. One was related to the need to either revise a procedural step in DEOP 400-1 "Fuel Restoration" to state the requirement to depressurize after the level decreases to -143 inches or to provide additional training on this specific step. The inspectors verified that the procedure has been revised to more explicitly require depressurization when the level decreased to -143 inches. The other item was related to whether the flow chart DEOPs were useable in the control room. The licensee had stated that a flip-up panel was to be installed behind the CRT display console

of each unit so the operators would have a place to spread out the DEOPs so they were usable. Since this panel was not yet installed, the inspectors could not determine the useability of the DEOPs in the control room. The December 1989 DEOP revisions, which utilize Revision 4 to the Owners Group EOPs, were much easier to follow than the previous versions and were more self contained (require less flipping back and forth between flow charts and procedures). On this basis, it is the inspector's opinion that once this flip panel is installed, the operators should not have difficulty using these flow charts (assuming this panel is large enough).

Human Factors Analysis (Section 7 of the Original Inspection Report)

In the original inspection report human factors concerns were identified in the following areas: decision steps/logic statements; cautions and notes, transitions, overall consistency; writer's guide; graphics; control room; and concerns related to the DEOP 500 Series procedures. Detailed concerns were identified in Attachment C to the original inspection report. The inspectors did not specifically address human factors concerns during the follow-up inspection. However, based on the limited review of the December 1989 revision to the flow charts, it is the inspectors opinion that significant improvements had been made in all the areas of concern identified in the human factors review. Some specific examples of improvements observed were: the elimination of notes in the flow charts and the incorporation of caution statements close to the applicable step; transitions within and between flow charts and procedures had been reduced, use of non-DEOPs had been reduced or eliminated; overall consistency of flow charts had improved; the graphics quality had greatly improved as well as the readability, curves and tables were included on the flow charts and located as close as possible to the applicable step, and typographical errors had been corrected. The control room had been completely remodeled since the original inspection. These modifications, many of which were the result of extensive DCRDR human factors concerns, had corrected many of the problems identified in the original EOP review. The revised flow charts should also make them easier to use in the control room and the flip-up panel to be installed by the licensee, if adequate in size, should eliminate the concern regarding the ability to effectively use the flow charts in the control room; the DEOP 500 series had been completely rewritten since that original inspection and most of the concerns identified had been corrected.

Verification and Validation (Section 8 of the Original Inspection Report

The inspectors reviewed the verification and validation programs utilized by the licensee during the approval process of the December 1989 revision to the DEOPs. The program in place was very comprehensive and the checklists used appeared to be sufficiently detailed to ensure that the procedures were consistent with the writer's guide.

The inspectors also compared DEOP 200-1, Primary Containment Control and DEOP 100, Reactor Control, with the PSTGs which was based on Revision 4 of the BWR Owners Group EPGs. Although for the most part, the DEOPs tracked the PSTG, inconsistencies were identified. Information in the PSTG was sometimes relocated to other DEOPs and information was sometimes added to the DEOPs for clarification that was not specified in the PSTG. Although the licensee believed that the flow charts could be reconstructed by a person experienced in working with EOPs, it is the inspectors opinion that the licensee should develop a bases document that clearly provides the justification for differences between the PSTG and the flow charts. Although the DEOP coordinator was very knowledgeable regarding the revisions that have been made to the flow charts since the original inspection, this corporate knowledge will be lost once he either changes positions or leaves the company. The inspectors therefore recommend that for all the programmatic changes to the DEOPs, (including deviations from the PTSG) the licensee should develop and maintain documented justification in auditable form.

d. EOP Open Items

The open items identified in inspection report 237/88012; 249/88014 items 4.a.(1), 4.a.(2), 4.a.(3), 4.b and 5 and Attachment B have all been addressed in this report and all but four items have been closed. The remaining open items are identified below:

(1) Attachment B, DEOP 200 Series, Item 3: Correction of problem related to legibility of the scale on strip chart of medium drywell pressure strip chart indicator. (Open Item 50-237/90009-02(DRP)).

(2) Attachment B, DEOP 500-1, Item 3: Identification of the location of the proper sources of service water. (Open Item 50-237/90009-03(DRP)).

(3) Attachment B, DEOP 500-2, Item 6: Proper use of the words "to" or "and" related to the 4 kv bus breakers. (Open Item 50-237/90009-04(DRP)).

(4) Attachment B, DEOP Equipment Storage Cabinets: Verify that procedure 005-10-15, when completed, is implemented. (Open Item 50-237/90009-05(DRP)).

No violations or deviations were identified in this area.

9. Report Review

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

While reviewing the Dresden July through December 1989 radioactive effluent report dated February 28, 1990, the inspectors noted a statement which indicated utilization of a release path for which Dresden had not been licensed. This statement read as follows:

> "In the one case where effluent monitoring equipment is not used, i.e., the burning of contaminated oil in the heating boilers, administrative controls are imposed to limit concentration in the heating boiler to less than 10 CFR Part 20 Appendix B, Table II, Column 1 and the contribution to overall dose to less than 0.1 percent of the total station annual release."

However, the licensee was not licensed to treat or dispose of licensed material by incineration (burning of contaminated oil in the heating boilers) in accordance with 10 CFR 20.305. The inspectors independently verified that the burning of contaminated oil in the heating boilers was not a current practice at Dresden and that the effluent report was in error. The licensee indicated that future issues of this report would be accordingly corrected.

The inspectors also reviewed the Secondary Containment Leak Rate Test Report dated February 26, 1990, which covered testing performed on November 26, 1989. The inspectors verified that this report met the requirements of Technical Specification 6.6.C.3 for that test.

No violations or deviations were identified in this area.

10. Open Items

Open items are matters which have been discussed with the licensee which will be further reviewed by the inspector and which involved some actions on the part of the NRC or licensee or both. Four open items disclosed during the inspection are discussed in paragraph 8.d.

11. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on April 2, 1990, and informally throughout the inspection period, and summarized the scope and findings of the inspection activities. The inspectors also met with the licensee's DEOP coordinator on March 14, 1990 and summarized the scope and findings of the EOP portion of the inspection.

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.