U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-237/90011(DRS); 50-249/900010(DRS)

Docket Nos. 50-237; 50-249 Licenses No. DPR-19; DPR-25

Licensee: Commonwealth Edison Company
Post Office Box 767
Chicago, IL 60690

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

Inspection At: Morris, Illinois

Inspection Conducted: April 2-6, 1990

Inspectors: F. Jablonski for 5-14-90
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Inspection Summary

Inspection on April 2-6, and 12, 1990 (Report No. 50-237/90011(DRS) 50-249/90010(DRS)).
Areas Inspected: Routine announced followup inspection to evaluate the progress made to resolve problems identified during the maintenance team inspection (MTI) documented in Inspection Reports 50-237/88029(DRS) and 50-249/88030(DRS).
Results: In general, the licensee's actions to improve maintenance and address the violations and unresolved item were acceptable. One violation was identified during this inspection with three examples of failure to follow procedures; and three unresolved items were identified that pertained to the adequacy of thermal overload sizing, the safety significance of missing problem analysis data sheets, and the change to the circuitry of a containment isolation valve without approved design documents.

DETAILS

1. Persons Contacted

Commonwealth Edison Company (CECo)

*E. Eenigenburg, Station Manager
*J. Achterberg, Assistant Superintendent, Work Planning
*D. Booth, Master Electrician
*K. Brennan, Regulatory Assurance Administrator
*J. Coonan, Conduct of Maintenance Coordinator
*R. Geier, Master Mechanic
*L. Gerner, Technical Superintendent
*J. Kotowski, Production Superintendent
*L. Sues, Maintenance Superintendent, Nuclear Engineering Department
*D. VanPelt, Assistant Superintendent, Maintenance

U.S. Nuclear Regulatory Commission (NRC)

*F. Jablonski, Chief, Maintenance and Outages Section
*S. DuPont, Senior Resident Inspector
*D. Hill, Resident Inspector
*M. Peck, Resident Inspector

*Denotes those present at the exit meeting on April 12, 1990.

Other licensee personnel were contacted as a matter of routine during the inspection.

2.0 Licensee Action on Previous Inspection Findings

2.1 (Closed) Unresolved Item 237/88017-21; 249/88018-21

Corrective maintenance procedures were not established for important safety-related and balance of plant (BOP) components. Licensee action to address this issue was described in the Nuclear Tracking System (NTS) as 237-100-88-0172 and 249-100-88-0181. In addition to writing 15 maintenance procedures on equipment identified by the Diagnostic Evaluation Team in 1988, the licensee reviewed other maintenance activities that were not governed by procedures. This review resulted in 26 additional procedures being written. The licensee also developed and implemented a procedure writing guide. This item is closed.

2.2 (Closed) Unresolved Item 237/88029-01; 249/88030-01

Trip armature travel measurements on safety-related 4 kV breakers were not performed. Prior to October 1988, the licensee performed trip latch clearance measurements as specified in the vendor manual issued in March 1967. In 1973, the vendor issued instruction GEI, 8871D which required measurement of the trip armature travel when preventive maintenance was performed. However, the licensee did not implement the change until October 1988. At the time of the maintenance team inspection approximately two thirds of the Unit 2 breakers and most of the Unit 3 breakers had not been checked for proper trip armature travel. The inspectors reviewed procedure SP 89-9-83, "Inspection and Maintenance of

General Electric 4 kV Magne-Blast Circuit Breakers Type AMH-4.75-250-00", Revision 1, and verified that the procedure required trip armature travel measurements to be taken. Additionally, with the exception of three breakers, all breakers have been measured for trip armature travel. This item is closed.

2.3 (Closed) Violation 237/88029-02; 249/88030-02

(Response to this violation was provided to the NRC in a letter dated May 11, 1989.)

a. Maintenance on 15 Unit 2 and Unit 3 breakers was not performed at the required frequency, some for as long as 17 years. In addition, the cause of 4 kV breaker failures was inadequately evaluated and the licensee failed to attribute the failures to improper maintenance. To date, three 4 kV breakers still remain to be overhauled. A maintenance procedure was developed that included inputs from electricians, electrical maintenance supervision, and a vendor specialist. Electricians interviewed during the inspection indicated that the overall electrical maintenance program and procedures were improved. No problems were identified with the 4 kV breaker maintenance program with the exception of frequency. The vendor manual recommended maintenance on the breakers at six months, one year and five year intervals and dependent on frequency of breaker operation. However, PMs were scheduled on the 4 kV breakers at five year intervals but without any evaluation or technical justification. The licensee indicated that the frequency of PMs would be reviewed. This item is closed.

b. PM had not been performed on the Unit 3 250V dc motor control centers (MCCs) since 1975. All 250V dc MCCs now have been overhauled. In addition, the maintenance procedure was completely revised to include additional vendor recommendations and acceptance criteria. The changes made to the procedure were similar to those made for the 4 kV breakers and with input from the electricians that performed the maintenance work. This item is closed.

c. Auxiliary switches (SBM) for Unit 2 and Unit 3 4 kV breakers and cubicles were not replaced even though the switches had a history of failure since 1982 and were at end of life. To date, two safety related breakers still require SBM switch replacements. Although, the SBM switches had a useful life of 10-15 years, the maintenance procedure required changing the switches on a 5 year interval. With respect to the SBM switches in the two 4 kV breakers, the licensee was uncertain of the status of the switches since the breaker serial numbers were not known. The safety significance was low since the power supplies to the safety-related buses were both diverse and redundant. This item is closed.

3.0 Follow Up to Maintenance Team Inspection

This inspection was conducted to evaluate the progress that the licensee had made in the area of maintenance since the NRC maintenance team inspection (MTI) in early 1989, which was documented in Inspection Reports 50-237/88029(DRS) and 50-249/88030(DRS). The inspectors reviewed historic data and various improvement programs. Some of the areas evaluated were planning and prioritization,

system engineering and root cause analysis, vendor manual control and incorporation of vendor requirements into procedures, histories of completed work requests, preventive maintenance, surveillances, and control of materials. At the beginning of this followup inspection, a walkdown of the plant was conducted to observe material conditions and upkeep of plant equipment and systems.

3.1 Historic Data and Maintenance Philosophy

The inspectors reviewed the latest available plant operations historic data from March 1, 1989, to February 28, 1990. Dresden Plant Status Reports dated December 1989 and February 1990 were reviewed to assess the effectiveness of the ongoing maintenance and improvement programs at Dresden.

Implementation of improvements were most notable with electrical maintenance, motor-operated valve overhauls, and check valve inspections. Plant performance related to the maintenance process was relatively consistent throughout 1989. Set goals were met in areas relating to maintenance including forced outage rate and non-outage corrective backlog.

However, plant status reports for the months of January and February 1990 indicated a higher percentage of forced outage rate and derating than any month in 1989. During January and February 1990 there were four forced outages caused by equipment failure including three reactor scrams that were attributed to BOP components. Since March 1989 there were 24 Licensee Event Reports (LERs) issued, which were classified by the licensee as maintenance/surveillance related. During the period most scrams occurred during periods of surveillance.

As described above, the team determined that some recent component failures, on face value, would tend to indicate that the established maintenance improvement programs were not effective yet. The team believed this to be untrue; however, due to an apparent lack of direction from the Corporate Nuclear Engineering Department on report contents, the annual licensee assessment report of the overall effectiveness of the maintenance program had not been documented by the Assistant Superintendent of Maintenance (ASM) as required by Nuclear Operatons Directive, NOD-MA.2, Revision 0, Exhibit "A". Therefore, based only on the obvious indications, there was insufficient information to adequately judge whether the maintenance improvement programs were totally effective.

3.2 Maintenance Improvement Program (MIP)

The inspectors examined the MIP and its implementation. The MIP was established to upgrade and enhance the maintenance process and is divided into four phases.

Phase I - INPO Maintenance Assist Review Team (MART) and security. 306 action plans have been initiated to address findings of which 297 have been completed.

Phase II - Conduct of Maintenance (COM) and 1988 assessments by INPO, NRC, and the licensee. 189 actions plans have been initiated of which 171 have been completed.

Phase III - 1989 assessments by INPO, NRC and licensee including the MTI findings and the licensee initiated Time Series Analysis (TSA)

(maintenance history review). 513 action plans have been initiated of which 215 have been closed.

Phase IV - 1990 assessments by the licensee and self imposed COM items. 88 action plans have been initiated of which 28 have been closed.

For the MTI findings, the licensee initiated 53 action items; 43 have been completed.

The team reviewed the licensee's MIP process and selected action plans. Based on the review, the team concluded that the licensee has established a good tracking program to address the various findings in the maintenance area. However, the following concerns were noted:

- Numerous action items initiated by the licensee to address findings by NRC, corporate and plant self assessments, mock SALP, and others were not consolidated and assigned to a single individual. For example, at least eight action items were written to address deficiencies with Problem Analysis Data Sheets (PADS), but assignments were made to different individuals for independent resolution.

- Feedback was not well established from maintenance supervisors to plant managers on status of maintenance issues.

- Several action items were considered complete by the site personnel but were not yet fully implemented. For example, some items were transferred to corporate for resolution but were incorrectly noted as 100% complete.

4. Review of Maintenance Related Corrective Actions

4.1 Augmented Inspection Team (AIT) Report No. 50-237/90004

The inspectors reviewed the following actions taken in response to the NRC AIT Report No. 50-237/90004. The inspectors noted that the licensee's corrective actions for several items identified in the AIT were still in progress. As the results of some investigation reports were to be received late in 1990, it would be appropriate for the NRC to further verify the licensee's corrective actions for these items at the end of 1990 or early 1991. Some preliminary results are described below.

4.1.1 Failure of Condensate/Booster Pump Motor

A fire in the 2B condensate/booster pump motor caused the pump to trip, which along with other failures, led to a reactor scram. The failed motor was replaced. The initial report issued on April 3, 1990, indicated that the cause of the motor failure was significant dirt in the coils. However, a final joint report of the licensee and General Electric Company was expected to be issued by August 1, 1990. Units 2 and 3 condensate/booster pump motors were cleaned except for 3D, which was scheduled for cleaning by April 23, 1990.

The maintenance department will continue to measure the polarization index of large motors. A temporary procedure was issued to clarify the insulation resistance/polarization index acceptance criteria. The permanent procedure is expected to be revised by June 30, 1990.

4.1.2 Failure of Condensate/Booster Pump 2B to Automatically Start

A modification to address the reactor feed pump suction header pressure recovery issue is being developed for possible implementation in 1992.

4.1.3 Failure of Reserve Auxiliary Transformer, TR22

The transformer was replaced but the causes for the failure were still being investigated. A final report is expected to be issued by June 1, 1990.

4.1.4 Closure of Outboard Main Steam Isolation Valve (MSIV) 2C

The MSIV solenoid electrically failed open. The solenoid was last replaced on February 11, 1989, in accordance with the PM requirement to replace solenoids every third refueling outage. The licensee stated that the failure of solenoids was not a recurring problem, and this was considered a random failure. The licensee was developing a surveillance procedure for these solenoids and was expected to be issued by July 1, 1990.

4.1.5 Failure of Electromatic Relief Valve Open Indicator Lamp Socket

The failed lamp socket was replaced. The failure was traced to dirt in the lamp sockets. The lamp sockets were periodically vacuumed. The licensee planed to develop a procedure to prevent lamp socket failures by May 1, 1990, which will be implemented by September 1990.

4.1.6 Failure of Main Generator to Trip on Reverse Power Conditions

The reverse power relays were replaced. The licensee stated that no similar events were reported from the licensee's other plants, where similar reverse power relays were used. However, further testing of these relays would continue regarding the effect of reactive power on the operation of these relays. A final report is expected to be issued by June 29, 1990.

4.1.7 Failure of 2B Shut Down Cooling Pump Discharge Valve to Open

The cause for the valve failure was traced to a broken motor pinion gear key, which was replaced. A similar failure occurred earlier on Unit 3. The gear keys in the motor operators on the shut down cooling pump valves will be replaced by June 30, 1990. The licensee also stated that similar improvement on other valves in the plant would be completed by December 1992.

4.2 Licensee Event Reports (LERs)

The inspectors reveiewed LERS that appeared to be maintenance related. The inspector also reviewed corrective actions committed to in eight other LERs of events that occurred from January to March 1989 and found that in four of the LERs, the licensee had not completed corrective actions. Many of the commitments made in the LERs were procedural changes; however, timely corrective actions were not evident.

LER 237-89001 - The LER was issued because of a Unit 2 inadvertent engineered safety feature actuation on January 21, 1989, which was due to an improper setting of an overcurrent relay by the Operational Analysis Department (OAD).

The licensee committed to revise the relay setting procedure. During the week of April 2, 1990, the inspector reviewed corrective actions but found that OAD had not completed the procedure revision.

LER 237-89019 - A Unit 2 reactor scram and a primary containment Group I isolation occurred on July 12, 1989. One cause for these events was a spurious main steam line area high temperature trip due to instrument drift of temperature switches, which were replaced. A new calibration method was being used to reduce the possibility of set point drift. The licensee was also considering a modification to improve the performance of these temperature switches. The other cause for these trips was the difficulty in resetting the "A" main steam line (MSL) logarithmic radiation monitor, which was replaced. The defective monitors were sent to the vendor for further evaluation. The vendor's report has not yet been received.

LER 249-89001 - A Unit 3 reactor scram occurred on March 25, 1989, due to a reactor water level transient and a turbine trip. Several equipment failures and malfunctions caused this event. The corrective actions taken were reviewed. The licensee replaced a failed condenser and mounted it externally on the 4 kV breaker; the breakers were cleaned on a five year cycle; a modification was done to improve the feedwater control; a modification to provide diesel driven pump to supply the isolation condenser was expected to be completed in 1992; and procedures were revised to correct the high pressure core injection (HPCI) oil cooling problem and the primary containment oxygen analyzer. Other proposed corrective actions were being appropriately tracked.

LER 249-89002 - A scram occurred on March 30, 1989, due to a spurious trip of the electrical protection assembly (EPA) breaker and a current lock up condition of a MSL radiation monitor. The corrective actions included replacing the EPA breaker and resetting and upgrading of the MSL radiation monitors. The EPA logic card was sent to the vendor for testing. Other corrective actions for this incident included revision of procedures, incorporation of caution regarding MSL radiation monitors, and revision to the OAD reverse power relays procedures that is expected to be completed by June 1, 1990.

4.3 Observation of Material Condition

The inspectors performed a plant walkdown that included an assessment of the systems and components for proper identification and tagging, and any unusual conditions such as water or oil on the floor. The areas inspected were generally clean and well maintained. However, the following were noted:

- The glass on Unit 2 drywell pneumatic backup supply pressure indicator gauge in the reactor building was broken and the pointer was bent. No deficiency or work request tag was found. Later a work request was generated.

- The licensee made good progress in the painting and labeling program.

- On April 2, 1990, during a walkdown of the reactor building, the inspectors observed a handwritten note, dated March 27, 1990, which stated that the Unit 2 250V dc ground detector strip chart recorder was not functional. The inspectors noted that a work request tag had not been placed near the vicinity of the recorder. The licensee was notified and at approximately

1:00 p.m., an instrument mechanic (IM) foreman arrived at the recorder and turned the recorder switch on. The IM foreman mistakenly believed that the problem was corrected. At about 4:30 p.m., the inspector noted that the chart had not moved. The licensee was notified again and during the evening, blanket WR 00166 was issued and corrective maintenance was performed. The inspectors were concerned about the lack of prompt corrective action to repair the above problem. Battery ground surveillances were performed once a shift (three per day) but none of the high voltage operators who performed the surveillance either wrote a work request or attempted to determine if a work request was issued. The licensee's procedure entitled, "High Voltage Operators Round Book" required that abnormal conditions either be corrected or reported to the Shift Supervisor and work requests initiated. The concern was that the operations personnel had not properly followed up on a known discrepant condition for approximately eight days until notified by the inspectors. This failure to follow the High Voltage Operators' procedure was considered to be a weakness.

- Several control rod drive (CRD) position lights in Units 2 and 3 vertical panels were not properly indicating control rod positions. Approximately 25% of the rod position lights were affected yet only one maintenance tag was noted. The unit operators stated that the operators do not depend on the vertical panel lights for a review of rod positions but would look at the screen of the rod worth minimizer or select a rod by the rod selector switch and obtain the rod position. The shift control room engineer confirmed the above statements.

  The inspector noted that the rod worth minimizer screen was rather small and was intended for prevention of inadvertent withdrawal of control rods out of sequence. Dresden Procedure DGP 3-2, "Normal Control Room Inspection", Revision 6, stated that, " . . . verify that all control rod position indications are normal on the vertical panel matrix. Check with computer print out OD-7." In addition, Procedure DAP 7-2, "Conduct of Shift Operations", Revision 15, also required that the nuclear station operator complete a degraded equipment log on each shift, with notation of any equipment in a degraded condition and/or which may require further action.

  The control room operators did not include the malfunctioning CRD position lights on the vertical panels in the degraded equipment log as required by the above procedure. The burned out CRD position indication lights appeared to be a long standing problem. Failure of the licensee to follow the station procedure and to verify that all control rod position indications were functioning and normal was considered an example of a violation of 10 CFR 50, Appendix B, Criterion V (237/90011-01A(DRS); 249/90010-01A(DRS)).

- The inspectors observed that eight of ten thermal overloads associated with the Unit 3 HPCI 250V dc MCCs were set differently than required by procedure DEP 040-6, "Safety-Related Motor Operated Valves Data and Settings", Revision 5, Section D, which stated that "The data on the lists cannot be changed without approval from the Nuclear Engineering Department NED." The back of the procedure listed a table with the required thermal overload settings. However, the licensee did not have a method to verify that the settings were correct. Consequently, the following thermal overloads were observed to be improperly set.

Valve No.	Required Setting	Actual Setting
1001-2A	1049C	1049A
1001-2B	1049C	1049A
1001-2C	1049C	1049A
1201-3	1036D	1036B
1301-2	1040C	1040D
1301-10	1023B	1023A
2301-3	1036D	1035A(+), B(-)
2301-14	1034D	1034C

In seven of eight cases listed above, the thermal overload settings were non-conservative (the valve motor would trip earlier than required). Other problems were noted, such as for valve 2301-3 where the positive and negative sides were set differently and for valve 1301-3 where the setting was not listed in the procedure. The failure to follow procedure DEP 040-6 was considered an example of a violation of 10 CFR 50, Appendix B, Criterion V (237/90011-01B(DRS); 249/90010-01B(DRS)).

The inspectors determined that the 250V dc MCC thermal overloads had not been tested since Unit 3 became operational. In addition, the vendor manual had an apparent discrepancy between the thermal overload tables and the full load current rating of valve motors. For safety-related valve 1201-3, the rated full load current was 16.5 amperes but the thermal overload for a size "2" starter, coil number 10177H1036A, was rated between 8.32 - 8.56 amperes. The vendor manual for coil numbers prefixed by 10177H stated, that " . . . coils selected from this table will allow a maximum of approximately 125% of rated current." It should be noted that the vendor information applied to continuous duty motors. However, using the above information the motor for valve 1201-3, if operated for several minutes, would have tripped at approximately 63% of full load current. The licensee stated that the thermal overload sizes were based on locked rotor current (LRC) not full load current because the valve was intermittently used. The "current versus time curve" for coil number 10177H1036A indicated that the specific time response curve for the coil was different than the generic curve provided by the vendor. For example, the generic curve indicated that at 125% of nameplate current the motor would trip in about 35 seconds, which does not take into account LRC. (The motor would trip in less than 35 seconds if LRC was considered). Valve 1201-3 stroked from fully closed to fully open in 33 seconds. The curve indicated that thermal overload 10177H1036A would trip in 160 seconds at approximately 125% of the rating for motor operated valve 1201-3. This item is unresolved pending review by the vendor to determine if the time versus curve for coil 10177H1036A was correct to within the vendor limits (237/90011-02(DRS); 249/90010-02(DRS)).

4.4 Completed Work Packages and Work Histories

The inspector reviewed eight completed work packages to determine if maintenance work was accomplished and documented. One problem was identified.

- The inspector noted that the post verification test required under Nuclear Work Request (NWR) D86234 and procedure DEP 040-12, "General

Electric 480 Volt Circuit Breaker Series Overcurrent Trip Device Test," Step F.2.0, was documented as not applicable for the A and C phases. The licensee stated that the tests were performed but that the work analyst was unable to read the original data sheets and gave the work package back to the electrical foreman. The foreman filled out the data sheet and routed the work package through QC. The QC supervisor signed off the package without noticing that at least two tests were not documented. The failure by the work analyst to review the work package the second time resulted in missed documentation of the post verification 300% breaker trip test for the A and B phases. Procedure DAP 15-01, "Initiating and Processing a Work Request", Revision 22, Section 9, required the work analyst to review the package. Failure of the licensee to follow procedure DAP 15-01, is an example of a violation of 10 CFR 50, Appendix B, Criterion V (237/90011-01C(DRS); 249/90010-01C(DRS)).

The licensee maintains the work histories by the Total Job Management (TJM) program. After the MTI, the licensee issued a maintenance memorandum No. 51, "Preparing Work Requests for TJM History," on June 9, 1989, which included a detailed work request checklist, to be completed by the maintenance foreman, after the work was completed. The inspector noted that the check list was being used and was included in the WR packages.

The licensee initiated a program for upgrading the data base of equipment identification on the TJM system and system walkdowns were being performed to complete associated records. Walkdowns were completed on 15 systems of Unit 2 and in various stages of completion on 15 systems of Unit 3. Progress in equipment identification appeared slow. Of approximately 14,000 station instruments, only about 4,000 had the station equipment identification numbers attached. The licensee stated that it would take about another two years to complete the task.

4.5 Work Planning and Prioritization

The planning department consisted of two groups for work planning, one group for outage planning and the other group for daily work planning. Procedures for the work planning organization and daily planning were in preparation and were expected to be issued in about a month. In addition to planning for the outages, this department prepares a two week look ahead schedule that consists of surveillances and other WRs based on priorities. Planning department personnel attended the daily and weekly planning meetings and updated the work schedules as necessary.

The inspector also discussed the planning and scheduling with the instrument department lead scheduler. Work planning in this department included walkdowns, planning and the preparation of work packages, assignments of work, and review of work packages after completion of work. The work was prioritized and taken up according to the priority.

4.6 Backlog of Maintenance

4.6.1 Corrective Maintenance Backlog

The MTI had previously identified a weakness in the prioritization of B2 WRs, which resulted in a large backlog of B2 WRs older than five days. The licensee

revised the WR prioritization process to agree with the Conduct of Maintenance (COM) and as a result the majority of the WRs were prioritized as B3. All B2 WRs were reviewed and were scheduled within five days. The TJM coordinator sends a weekly list of all WRs prioritized as A, B1, and B2 to the Assistant Superintendent of Maintenance and to the master mechanics for review and scheduling. This considerably reduced the backlog of B1 and B2 WRs. The backlog of B1 WRs was almost eliminated. There were only three instrument WRs prioritized as B2 pending on March 31, 1990.

The inspectors determined that on April 3, 1990, the non-outage CMWR backlog was 587 for mechanical maintenance, 163 for electrical maintenance, and 172 for instrumentation maintenance. The CM backlog had increased by 33 CMWRs since the previous MTI in February 1989. The inspectors concluded that the increase was not significant and the total backlog was slightly above the corporate goal. The inspectors reviewed several CMWRs and determined that none had impact on operability. The inspectors noted that the licensee had made improvements in estimating manhours required for each work request. The February 1989 MTI reported that the actual hours was twice the estimated hours. This inspection noted that the actual manhours required was approximately 20% over the estimated.

4.6.2 Preventive Maintenance Backlog

Based on review of licensee records, the inspectors determined that on April 3, 1990, the total PM backlog was 576. This included periodic, planned, and predictive maintenance WRs. This backlog was considered to be within the current maintenance staff capabilities.

The ratio of PM hours to total maintenance hours averaged 55% during 1989, which was higher than the plant goal of 42%. A review of the scheduled PMWRs backlog identified a few isolated misclassifications of CMs as PMs; however, the inspectors noted a good improvement in correct CM/PM classification. This was identified as a weakness in the 1989 MTI.

4.7 Post Maintenance Testing (PMT)

Due to time constraints the team was not able to conduct a comprehensive review of the post maintenance testing program and implementation. However, the team noted that several licensee action items relative to PMT still remain open. Open Action Item NUS EVAL. 04.00, initiated September 1989, identified a need to monitor the PM program by reviewing the work performed against the PMT specified in order to assess the effectiveness of the PMT program. Also, Licensee Open Action Item Corp. Assess. 04.02 initiated December 1989, requested that work packages be reviewed to insure the latest PMT requirements are in the packages prior to being sent to the field.

During the MTI inspection, the team identified weaknesses in the post maintenance testing program. Subsequently, an interim post maintenance testing program was developed. The interim program was implemented by work analysts who reviewed each work package and identified the post maintenance verification or test to be accomplished. The work analyst used a matrix that outlined each major component type and the test to be performed. The inspector reviewed several work packages and noted that adequate post maintenance testing was performed.

The licensee planned to use the interim program until a formal program is to be developed and approved.

4.8 Preventive Maintenance and Surveillance

A study conducted in 1988 by a contractor identified 15 systems for a detailed evaluation of maintenance requirements, based on the previous problems. A system unavailability study was conducted in January 1990 on four systems; high pressure core injection, diesel generators, low pressure core injection, and ac/dc distribution systems. The licensee was currently reviewing the contractor's recommendations.

It appeared that BOP components have not been maintained with the same vigor as safety-related components. For example, only 97 of 332 BOP MOVs have been overhauled and not all BOP valves were in the General Surveillance (GSERV) Program. Also, 480 Vac BOP MCCs have not been put in GSERV for periodic PM activities. A weakness was observed in sizing of thermal overloads on BOP motor operated valves fed from the HPCI MCCs. The thermal overload size and position were not documeted, as a result, it is unknown if proper design consideration was given to these BOP valves. In addition, progress with BOP surveillances appeared to be lagging. As of January 31, 1990, out of 485 surveillances in the non Technical Specification or non-EQ related areas, 79 were past due which was 16% against the goal of 6%. The team concluded that a need exists to prioritize maintenance on BOP components and base it on the component's failure affect on safety-related systems.

4.9 Technical Support

4.9.1 System Engineers

The system engineers concept was started about two years ago. Currently, the station has 31 system engineers, with experience ranging between two months and six years. The system engineer concept has not yet taken root. In general, the system engineers did not appear to be involved with equipment failure and root cause analysis. The system engineers neither received completed work requests, nor maintained system "Note Books."

The technical staff supervisor stated that there were plans to develop a "Conduct of Tech Staff" similar to the "Conduct of Maintenance" including a detailed program and procedures for implementing the "System Engineer", which would be developed after the issue of "Conduct of Tech Staff" in September 1990.

4.9.2 Problem Analysis Data Sheet (PADS) Program

The licensee had implemented a generic program for the identification and resolution of maintenance problems by use of a PADS. The program was somewhat controlled by Maintenance Memorandum No. 38, "Implementation of Draft Procedure, Analysis of Maintenance Problems," dated September 15, 1989. PADS were used to evaluate root cause and corrective action if safety-related equipment failed a surveillance or post maintenance operability test, was declared inoperable, demonstrated a set number of failures over a specified time period, or exceeded a predetermined number of manhours to repair. The 1989 MTI identified a weakness in the slow progress in the resolution of PADS in that only 13 of 185 had

been resolved. During this inspection it was noted that 248 of 432 PADS had been completed. However, upon further review, it was noted that 78 PADS were "missing"; 35 from 1988 and 43 from 1989. The licensee was aware of those PADS but had not taken any action to locate or reconstruct them in order to complete a root cause analysis. At the completion of this inspection, the licensee developed an action plan for the missing PADS, which consisted of: (1) reviewing the list of missing PADS to determine if any were covered on a duplicate PADS, and (2) reviewing the remaining PADS and determining if reconstruction of the PADS was warranted. If so, a new PADS would be written, if not, the justification would be documented. Neither the inspectors or the licensee could determine the safety significance of the missing PADS; therefore, this item is considered to be unresolved until a review of the reconstructed PADS is conducted (237/90011-03(DRS); 249/90010-03(DRS)).

The inspectors also reviewed the timeliness of resolution for a sample of 83 open PADS given to Technical Staff the week of March 26, 1990. (According to MM-38, the PADS were required to be: (1) signed by the Master Mechanic/ Electrician/I&C after completion of maintenance and initial root cause determination; (2) the PADS were then given to the PADS Coordinator; and (3) then assigned to the Technical Staff for final root cause and corrective action.)

There were 13 PADS greater than 18 months old, 32 were 12 to 18 months old, 23 were 6 to 12 months old, and 15 were less than 6 months old. These PADS had been held at various points along the process path and the licensee did not know the reason for the untimeliness of the Technical Staff's receipt of the PADS. The inspectors concluded that the use of MM-38, which essentially was a draft procedure, contributed to personnel involved in the PADS process treating the PADS program as a "trial" program and therefore exhibited less concern and stringent controls on the tracking and processing of the outstanding PADS.

The licensee established a Technical Staff backlog goal of 10 to 15 PADS but the current backlog was 157. There were 27 engineers that evaluated PADS who were also responsible for the evaluation of Deviation Reports, modifications, and other day-to-day system activities. The inspectors were told that the engineers worked approximately 10 to 15 hours of overtime per week in order to keep pace with the work load even without the recent increase in the backlog of PADS. Based on current circumstances the inspectors concluded that the licensee's backlog goal was not realistic nor achievable.

4.9.3 Trending and Predictive Maintenance

The maintenance trending program, based on work history, was improving. Equipment/ component history relied heavily on Total Job Management (TJM) "header" record data; therefore, improvements in this area ultimately led to improved and accurate maintenance trending data. From March 1989 to February 1990, approximately 23,000 header records data had been added to the TJM. Fifteen systems were identified as priority for complete TJM maintenance history. Header records for the 15 systems were completed for Unit 2 and 60% were completed for Unit 3, which should be completed by December 1990.

The MTI identified that Maximum Occurrence Reports were issued when two corrective WRs were written on a document. Because of the improved and detailed header records for components, Maximum Occurrence Reports were decreasing. Items were

no longer "dumped" into a generic equipment identification (EID) for lack of an accurate EID for that particular component.

4.9.3.1 Thermography

During the MTI, the licensee indicated that a program to implement predictive maintenance, including a thermography device to detect loose electrical connections, would be initiated. Currently, no formal program has been initiated for thermography. In October 1989, the licensee hired a contractor for two days to take baseline data of some electrical components including the "D" condensate/booster pump motor that failed in January 1990 and indirectly caused a reactor scram. Although not conclusive, indications were that the "D" condensate pump motor was reading 30°F higher than the other three pump motors. On April 3, 1990, the licensee received a thermographic device and indicated that a thermography program would be initiated.

4.9.3.2 Lube Oil Trending

During the MTI lack of a comprehensive oil trending program was identified. Currently, various oil sampling and analysis techniques are utilized with the intent to choose one program for oil all analysis and trending. The licensee is approximately 30% complete with this corrective action; therefore, the inspectors could not assess the progress. The current practice includes sending samples offsite for spectrochemical analysis. Results were tracked, distributed to the system engineer, and recommendations from the contracted analysis was incorporated.

A new equipment trending program will be utilized to trend and consolidate all vibration, oil analysis, IST, and thermography results over many years and use the high and low alarm points as acceptance criteria. This data will be given to the system engineers for evaluation of trends on a monthly basis. This new program was in the initial stages of implementation and could not be assessed by the inspectors. Currently, the licensee trends and distributes vibration data to the system engineer for review.

4.9.4 Valve Testing

4.9.4.1 MOV Overhauls

The licensee overhauled 100% of the EQ safety-related valves, 100% of non-EQ safety-related valves (increased from 76%), and 29% of the BOP MOVs (increased from 10%). Many of the Unit 2 BOP MOVs are scheduled for overhaul during the fall 1990 outage. All BOP MOVs are to be completed by June 1992. Diagnostic testing was completed on 65 valves with 50 scheduled for the Unit 2 refueling outage and 50 scheduled for the Unit 3 refueling outage. The licensee showed continued progress in the completion of the MOV improvement program; MOV failures have steadily decreased over the past three years.

4.9.4.2 Check Valves

A check valve inspection program was implemented that included the periodic inspections necessary to ensure that check valve internals were intact and not experiencing abnormal wear. The scope of the program was much broader than that required in Significant Operating Event Report (SOER) 86-03 because

Dresden had included check valves measuring two inches and under. To date, 115 of 205 check valves have been inspected. When abnormal wear was identified another check valve in the same category was also inspected to evaluate the pervasiveness of the anomalies. The increased scope and investigation of common mode failure technique was considered a strength.

4.9.5 Vendor Manual Control and Incorporation of Vendor Requirements into Procedures

Only limited improvement was noted in the area of vendor manual control since the MTI was completed. The vendor manuals available for work at the station cover about 1025 models, of which only 424 (16%) were controlled. Out of an estimated 850 safety-related equipment models only 101 (11.9%) had controlled vendor manuals available. The inspector reviewed seven controlled vendor manuals selected at random and no problems were identified. However, the applicable equipment was not indicated on the manuals and there was no cross reference to the procedures that the vendor manuals were used.

As a result of discussions with the system and maintenance engineers, the inspector concluded that a detailed evaluation of the vendor manuals was not done to include the applicable vendor recommendations in the station procedures. The licensee stated that a corporate vendor contact program is being established and is expected to commence in July 1990. The corporate office will contact the vendors on behalf of all the CECo nuclear plants. The licensee also stated that the vendor manuals at each of the stations would be sent to the corporate office for a detailed review. It appeared that the complete implementation of this program would take several years before the results of such detailed reviews would enable the vendor recommendations to be incorporated into the appropriate station procedures.

4.10 Station QA Audits and Surveillances of Maintenance Activities

The team reviewed the audits and surveillances performed by the licensee since February 1989 in the maintenance area to determine the effectiveness in identifying maintenance related problems. Four audits and a number of surveillances were completed by the licensee since February 1989. No adverse findings were identified by the licensee even during a period when other assessments of maintenance identified numerous problems specifically in electrical maintenance. The inspectors determined that QA audit reports 12-89-36, 12-89-37, 12-89-38 and 12-89-42 were narrow, shallow, and compliance oriented. For example, QA Audit QAA-12-89-42, Question 8, required the auditor to verify that the PM recommendations from the vendor equipment manuals were reflected in the maintenance procedures. To accomplish this, the auditor merely verified that the procedures referenced the vendor manuals without checking that the procedures actually contained the vendor recommendations. To correct this, the team was informed that for audits conducted in 1990, an improved "Standard Audit Checklist" and other improvements, such as longer time for audits and use of maintenance experts as auditors, will be instituted.

QA surveillance item QAS 12-89-111, written August 8, 1989, identified that work was performed outside the scope of WR 81534. The WR, dated in January 1989, stated to troubleshoot safety-related containment isolation valve MOV-2-1201-2. The work performed section of the WR stated that a wire was removed from a terminal block and taped up. This was done by a craftsman

contrary to the design drawing, which indicated that the wire was to be terminated on the terminal block, sealing in the valve opening circuit. As a result, the sealed-in opening circuit of the valve was removed and made into a throttling circuit on an open signal. The same unapproved change apparently was performed on Unit 3 MOV-3-1201-2. The licensee stated that the Unit 2 circuit has been modified to seal-in on open and the Unit 3 open circuit will be modified to its original configuration during the next refueling outage. It should be noted that both valves would still perform the closed isolation function on demand.

The team had two concerns: (1) that an electrician could perform a functional logic change to the valve's circuitry without going through the design change process, specifically the 10 CFR 50.59 review; and (2) QC did not discover the design change during the QC release and final review stages in February 1989. A DR was not written until August 1989 and still remained open at the time of this inspection. Also, the package went through all the approval cycles and was being completed and signed off without a concern being raised. This item unresolved (237/90011-04(DRS); 249/90010-04(DRS)).

Since the team was not able to observe ongoing maintenance activities during this inspection, QC involvement during maintenance activities could not be examined. This was identified as a concern during the MTI. The inspectors noted, however, that licensee Action Item CORP. ASSESS.01.00 requested that this area be examined during the upcoming corporate maintenance assessment in June 1990.

4.11 Control of Materials and Parts

The MTI report stated that safety-related items were procured from a vendor not listed on the quality approved bidders list. The licensee stated that all Dresden BWR engineering procurements were now being routed through the station store keeper for a proper processing. The inspector did not identify any recent procurements from unapproved vendors.

The MTI report also stated that materials delivered to a contractor's hold area were picked up and misplaced. The licensee stated that a new contractor now maintained a hold area and maintained all the documentation for receipt inspection for items stored in the contractor's warehouses or the items were immediately forwarded to station Engineering Construction Group at the station, thereby reducing the possibility of a "loss" of material.

The inspector reviewed the contractor's hold area and warehouse facilities. Procedure SP-1X-02, "Material and Equipment Identification and Inspection Status Control," Revision August 25, 1989, required that identification of quality related material be maintained during storage, and procedure SP-1X-03, "Material and Equipment Storage and Control," Revision August 30, 1989, required that care be taken in storage areas to ensure compliance with safety policies and procedures.

Contrary to the above, on April 4, 1990, the inspector observed that four, one inch sealing locknuts were stored in safety related storage area No. 30 without any identification markings. Failure to follow procedures to control the storage of safety related materials is considered a violation of Criterion V of 10 CFR 50, Appendix B (237/90011-05(DRS); 249/90010-05(DRS)).

However, the violation was not cited because the criteria specified in Section V.A of the Enforcement Policy were satisfied. The violation would normally be classified as a Severity Level V and was an isolated instance; the violation was promptly corrected, by discarding the sealing rings; and adequate administrative controls were in place to prevent recurrence.

5.0 Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items disclosed during this inspection are included in Paragraph 4.3, 4.9.2, and 4.10 of this report.

6.0 Exit Meeting

The inspectors met with licensee representatives (denoted in Paragraph 1) on April 12, 1990, at the Dresden Plant and summarized the purpose, scope, and findings of the inspection. The inspectors discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents or processes as proprietary.