U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-237/91003(DRP); 50-249/91003(DRP)

Docket Nos. 50-237; 50-249 Licenses No. 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: December 30, 1990 through February 15, 1991

Inspectors: D. E. Hills
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Approved By: B. L. Burgess, Chief
Projects Section 1B

3/8/91
Date

Inspection Summary

Inspection during the period of December 30 through February 15, 1991 (Reports No. 50-237/91003(DRP); No. 50-249/91003(DRP))

Areas Inspected: Routine unannounced resident inspection of previously identified inspection items, plant operations, maintenance/surveillance, engineering/technical support, safety assessment/quality verification, systematic evaluation program items, TMI action plans requirements followup and report review.

Results: One violation was identified involving a reactor protection system response time testing surveillance procedure which prescribed usage of test equipment in a fashion that resulted in measurements that were inconsistent with Technical Specification requirements (Paragraph 4.b.1).

One unresolved item was identified which involved the adequacy of design control measures regarding input parameters and calculations for a modification package. The item is pending a verbal response from the licensee on specific concerns that were expressed to the licensee (Paragraph 5.a).

Plant Operations

Problems delineated in this report are indicative of the continuation of the declining trend previously reflected in Inspection Report No. 50-237/90027; 50-249/90026 and No. 50-237/90023; 50-249/90023 in this functional area. The failure to adequately utilize the drywell venting procedure or to obtain a temporary procedure change prior to deviating from the drywell venting procedure was a commonly accepted practice. Plant management did not appear to be aware of this specific practice and had taken actions in response to previous violations to ensure adherence to procedures. These actions would appear to have been ineffective (Paragraph 2). The inspectors regarded the licensee's practice of not declaring equipment inoperable when it was rendered non-functional for surveillance testing to represent weak or non-existent controls (Paragraph 2). However, the inspectors observed the operators perform adequately during the conduct of several startup and shutdowns, including some in an abnormal condition (Paragraph 3).

Maintenance/Surveillance

Problems delineated in this area are indicative of the continuation of the declining trend previously reflected in Inspection Report No. 50-237/90027; 50-249/90026 and No. 50-237/90023; 50-249/90023. The basis for this conclusion was the inattention to detail of maintenance personnel involved in a June 1988 surveillance procedure change and in conduct of the surveillance since that time resulting in a failure to ensure the proper application of test equipment (Paragraph 4.b.1). Another basis was the the damage to turbine components and resulting extension of the Unit 2 refueling outage being indicative of continuation of work practice problems encountered earlier in the outage (Paragraph 4.a). One item, however, reflects a strength in this functional area. The inspectors regarded the licensee's identification of a failure to test Standby Gas Treatment System heater interlocks to be an example of the effectiveness of the Procedure Upgrade Program and the diligence and attention to detail exhibited by the maintenance staff performing the review (Paragraph 4.b.2).

Engineering/Technical Support

The long delay in the licensee's analysis of cracks found in Unit 2 reactor vessel head closure studs in January 1989 was regarded by the inspectors to be a failure of Technical Staff personnel to pursue resolution in a timely manner. This reflected inspector concerns regarding the effectiveness of Technical Staff interface with offsite groups such as the Systems Materials Analysis Department (Paragraph 5.b).

Safety Assessment/Quality Verification

A review of the licensee's quality control (QC) feedback sheets indicated the QC organization's initiative to go beyond requirements in pursuit of problem identification and resolution (Paragraph 6).

DETAILS

1. Persons Contacted

Commonwealth Edison Company

*E. Eenigenburg, Station Manager
*J. Kotowski, Production Superintendent
L. Gerner, Technical Superintendent
E. Mantel, Services Director
*D. Van Pelt, Assistant Superintendent - Maintenance
J. Achterberg, Assistant Superintendent - Work Planning
*G. Smith, Assistant Superintendent-Operations
*K. Peterman, Regulatory Assurance Supervisor
M. Korchynsky, Operating Engineer
B. Zank, Operating Engineer
J. Williams, Operating Engineer
R. Stobert, Operating Engineer
T. Mohr, Operating Engineer
M. Strait, Technical Staff Supervisor
*L. Cartwright, Quality Control Supervisor
J. Mayer, Station Security Administrator
D. Morey, Chemistry Services Supervisor
D. Saccomando, Health Physics Services Supervisor
*K. Kociuba, Nuclear Quality Programs Superintendent
*D. Lowenstein, Regulatory Assurance Analyst
*B. Viehl, Nuclear Engineering Department Design Supervisor
*K. Yates, Onsite Nuclear Safety Administrator
*T. Gallaher, Nuclear Quality Programs Engineer
*G. Kusnik, Quality Control
*D. Gulati, Master Instrument Mechanic

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 (50-237/90017-02): Several examples of inadequate equipment outages which resulted in adverse consequences. The inspector reviewed the licensee's corrective actions including provisions to ensure appropriate drawings were utilized and development of a self check program. The inspectors determined that measures had been taken in accordance with licensee commitments and have no other concerns in this area.

(Closed) Unresolved Item (50-237/90023-09): Review usage of quality control feedback sheets. This item is addressed in Paragraph 6. The inspector has no further concerns in this area.

(Closed) Unresolved Item (50-237/90027-04): On December 7, 1990, the inspectors found that the service air supply to three of the Unit 3 drywell purge and ventilation fan dampers had been disconnected. Further review found that the length of time that the dampers were disconnected could not be positively determined, due to the number of procedures involving inerting, deinerting, and venting of the containment which specified manipulation of the drywell purge dampers. However, it was found that venting of the drywell was performed on December 3 and again on December 5, 1990.

According to Dresden Operating Procedure (DOP) 1600-1, Revision 5, "Normal Venting of Drywell or Torus," the air supply to the dampers was required to be disconnected to cause the dampers to fail open and then reconnected following the evolution. Discussions with the cognizant Nuclear Station Operators (NSOs) indicated that the NSOs were venting the drywell on December 3 and 5 through what they believed were closed dampers in order to gradually reduce pressure in the primary containment. They did not utilize that portion of DOP 1600-1 to fail open and then restore the dampers and therefore did not identify that the dampers were already in the failed open position. It was fortuitous that the dampers were already open for undetermined reasons such that venting was conducted with open dampers as prescribed in the procedure. Therefore, this was not considered to be a violation of procedural requirements.

The specific safety significance of having the dampers disconnected was minimal due to primary containment isolation valves upstream of the process flow and reactor building ventilation system which provided isolation capabilities. Of greater concern was apparent operator attitude toward procedure adherence. Interviews with other operating personnel indicated that performance of this evolution without disconnecting and reconnecting the dampers was not limited to the involved individuals.

In one case, knowledge of the procedure upgrade program was used as a contributing rationale. The use of this program by selected individuals within the licensee's organization as a basis for not pursuing needed procedural changes was considered inappropriate by the inspectors. The December 3 and 5 occurrences of venting of the drywell were not the only cases of procedural adherence problems. A recent violation involving operator failure to follow procedure resulting in a reactor cavity overflow event and a recent non-cited violation involving maintenance failure to follow procedure resulting in draining of the reactor cavity are additional examples. The licensee's corrective actions involved inclusion of the first event in a meeting with supervisors on October 17, 1990 and instructions given to Shift Engineers regarding procedure adherence on October 24, 1990. These corrective actions appear to have been ineffective. The licensee further emphasized adherence to procedures to all licensee personnel during meetings conducted February 26-27, 1991, and recent inspections have not identified additional problems in this area. Therefore, the inspectors have no further concerns in this area.

(Closed) Unresolved Item (50-237/90027-07): On November 18, 1990, the inspector noted that a temporary vacuum pump and hose assembly were utilized to augment the filtering capability of the fuel pool cleanup system during refueling operations. A review of the Updated Final Safety Analysis Report (UFSAR) indicated that this did not constitute a change in the facility as described in the UFSAR and therefore did not require a 10 CFR 50.59 safety evaluation to be performed. Following identification of this issue by the inspectors, the licensee determined that any potential adverse effects from this evaluation were bounded by existing analyses. Therefore, the inspectors have no further concerns in this area.

(Closed) Unresolved Item (50-237/90027-12): Complete review of licensee's overtime policy in regards to Generic Letter 82-12. The licensee's program met formal commitments in this area. However, some instances were identified in which the licensee's program did not appear to meet the intent of the generic letter; these were delineated in inspection report 50-237/90027; 50-249/90026 and forwarded to NRC management for review. This item is closed.

(Closed) Unresolved Item (50-237/90023-05): Review licensee's practice of not declaring equipment inoperable when rendering it nonfunctional for the purpose of conducting Technical Specification required surveillance testing. During this review, the following specific examples were identified:

High Pressure Coolant Injection (HPCI) System - Performance of the low pressure trip functional test resulted in the isolation of the HPCI steam supply valve. In the test configuration, the HPCI system would fail to respond to an automatic initiation signal.

Isolation Condenser (IC) System - The IC functional test inhibited automatic system initiation by disabling of one of the two required logic channels (Initiation logic was two out of two). The IC high flow isolation test prevented the IC from automatically initiating by the closure of the steam supply line.

Torus to Reactor Building Vacuum Breaker (TVB) - The TVB circuit card functional test prevented initiation of the vacuum breaker by interrupting the torus differential pressure transmitter (DPT) signal to the valve actuation logic. The TVB DPT calibration procedure prevented the TVB function due the manual isolation of the DPT from the torus.

Diesel Generator (DG) - The DG monthly surveillance test manually loaded the DG and rendered the load shedding feature nonfunctional. In the case of a loss of coolant accident coincident with a loss of offsite power during the surveillance performance, the diesel generator would attempt to pick up all the non-vital loads which were powered from the bus prior to the event in addition to the emergency loads. These loads could be in excess of the design capacity of the DG.

No discussion exists in Technical Specifications regarding the definition of operability as it applies specifically to systems undergoing surveillance testing. In addition, having personnel available to manually perform normally required automatic actions, if needed, was not credited in the Updated Final Safety Analysis Report (UFSAR), and therefore cannot be used to justify an operability determination. Whenever a system, subsystem, train, component, or device is not capable of performing its specified safety function(s), for any reason, including surveillance testing, that equipment is inoperable for Technical Specification purposes and appropriate Technical Specification action statements apply.

The licensee did not provide tracking to ensure Technical Specification action statements were not exceeded for equipment inoperable due to surveillance testing. However, the inspectors review of surveillance test intervals did not identify any instances in which a Technical Specification action statement was inadvertently exceeded under these circumstances and, therefore, no violations of NRC requirements were identified in this area. This was undoubtedly due to the short duration of most surveillances in comparison to the required action statement time durations. In light of the failure to provide such tracking mechanisms and the potential applicability of Technical Specification action statements to such circumstances, the inspectors considered the licensee controls to be weak or nonexistent.

The other portion of this item dealt with the licensee's delay of investigation of control rod drive accumulator alarms. A review of Technical Specifications indicated that no action statement could be exceeded unless more than one accumulator in the nine-rod array were inoperable. The alarm response procedure required that the nine-rod array be specifically checked. Therefore, two inoperable accumulators would be identifiable and higher priority could be placed upon resolving the problem. As no specific cases were identified where this was not done and no Technical Specification action statements were identified as having been exceeded, the inspectors have no further concerns in this area.

(Open) Open Item (50-237/90027-14): Perform sample inspection of Systematic Evaluation Program (SEP) topic resolutions. Additional items confirmed by the inspectors are listed in Paragraph 7. This item will remain open pending completion of licensee confirmation of topic closures and completion of the NRC sample inspection.

No violations or deviations were identified in this area.

3. Plant Operations (71707, 71711 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.

During the inspection period, several startups and shutdowns were conducted on both units. Several startups and shutdowns on Unit 3 were conducted in an off-normal condition, in that, only one recirculation pump was operating. The inspectors observed that the operators effectively dealt with this condition and performed adequately during these evolutions.

Each week during routine activities or tours, the inspectors monitored the licensee's security program to ensure that observed actions were being implemented according to their approved security plan. The inspectors noted that persons within the protected area displayed proper photo-identification badges and those individuals requiring escorts were properly escorted. The inspectors also verified that vital areas were locked and alarmed. Additionally, the inspectors also verified that personnel and packages entering the protected area were searched by appropriate equipment or by hand.

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.

The following operational occurrence was also reviewed:

On February 13, 1991, Unit 2 automatically scrammed from 60 percent rated thermal power due to an automatic Group 1 (main steamline) primary containment isolation. The isolation was caused by a spike on the main steamline radiation monitors due to resin intrusion from the reactor water cleanup (RWCU) system. Control room operators responded appropriately to the scram. The resin intrusion resulted from a leaking RWCU demineralizer isolation valve while changing out the resin bed on a demineralizer. The leakage was caused by the manual valve being slightly open although the remote valve position indicating pointer (on the other side of a valve gallery wall) indicated the valve was fully closed. The licensee postulated the discrepancy was due to long term loosening of valve operator components. The licensee planned to perform future resin bed change outs with the entire RWCU system isolated. The licensee did not plan to immediately repair the valve due to high radiation levels in the area. The inspectors noted that licensee management's investigation of the scram was extensive and comprehensive.

No violations or deviations were identified in this area.

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

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.

Reactor Recirculation Pump 3B Seal Replacement
Reactor Recirculation Pump 3B Bearing Replacement

A Unit 2 startup was commenced on January 4, 1991, following a refueling outage that began on September 23, 1990, which was originally scheduled to end on December 4, 1990. The delay was attributed to recirculation piping overlays, valve work, Source Range Monitor (SRM) problems during fuel reload and a main generator hydrogen seal leak. Problems were encountered while rolling the main turbine which necessitated tripping the turbine. Subsequent licensee inspection identified extensive damage to turbine components. Damage was caused by lube oil blockage due to a blank being left in a lube oil strainer following maintenance. Although the work package prescribed removal of the blanks, this one was missed by maintenance personnel. The inspectors regarded this error, which resulted in an additional one month delay for repairs, to be indicative of the type of work practice problems encountered during the first half of the refueling outage. However, the error involved balance of plant equipment with no safety significance and did not present a direct challenge to safety systems.

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:

Reactor Protection System Response Time Testing
Service Water Outlet Radiation Monitor Calibration
Generator Load Reject Instrument Response Time Surveillance
New Fuel Receipt Inspection
Turbine Control Valve Pressure Switch Calibration
Containment Cooling Service Water Pump Test
Quarterly LPCI System Pump Operability Test

(1) While reviewing Dresden Instrument Surveillance (DIS) 500-9 "Reactor Protection System (RPS) Functional Time Response Tests" the inspector noted a discrepancy between the procedure and Technical Specification requirements. A scram signal was processed through the RPS logic beginning with the opening of the sensor contacts followed by the de-energization (and subsequent contact opening) of the HFA relays. This was followed by the de-energization (and subsequent contact opening) of the scram relays (108s) resulting in the de-energization of the scram pilot solenoid (SPS) and opening of the scram valves. Technical Specification 3.1.A required the response times from the opening of the sensor contacts (108 relays), to be verified less than 50 milliseconds (msec). On June 3, 1988, DIS 500-9 incorporated a Double Power Systems Timer (DPST), a portable solid state electronic instrument, to measure the RPS response time. Per DIS 500-9, the DPST was configured such that the timer start gate was connected in parallel across the HFA relays and the stop gate was connected in parallel across the SPSs. The test was initiated by the

simulated opening of the scram sensor contact by the removal of the fuse in the HFA relay circuit. Plant personnel believed the DPST start and stop gates would be triggered on a plus or minus 0.5 volt change (from 120 Volts AC pre-trip value) across both sets of relay coils and capture the response time of both the HFA and scram (108) relays.

The inspector identified, from a review of the vendor manual, the DPST would not trigger until voltage across the HFA relays dropped to an absolute value of 0.5 volts, not just a change of 0.5 volts. Based on the review of RPS response time relay voltage plots generated on a Gould recorder, a delay may occur between the opening of the scram sensor contacts and voltage decay to 0.5 volts across the HFA relay. Additionally, because the DPST stop gate was also connected in parallel to the SPSs, the ending signal was also delayed as a function of the circuit time constant for the SPSs. Because of the test configuration specified in DIS 500-9, the DPST unnecessarily included the response time between the scram relays (108s) and SPSs, and omitted measuring the response of the HFAs. There was no evidence that the conservatism on the back end of the logic timing would always outweigh the nonconservatism on the front end.

The licensee bench tested two HFA relays, configured similar to the RPS logic, to better understand the effect of the voltage decay time across the relays, and to assess the safety significance of the DPST when used in conjunction with DIS 500-9. Based on the results of the bench testing, no conclusion could be correlated that the DPST, when connected across the relay coils per DIS 500-9, provided equivalent response time as required by Technical Specifications. However, testing did indicate, that if properly configured constant with the manufacturer's recommendations and within the physical limitations of the device, the DPST could be a valuable tool for measuring RPS response time in the future.

The failure of DIS 500-9 to adequately prescribe steps to measure the RPS response time in accordance with Technical Specification requirements is considered to be a violation (50-237/91003-01(DRP)) of 10 CFR 50, Appendix B, Criterion V.

Following identification of the problem, and prior to startup, the licensee repeated RPS response time testing, on both units, using a multichannel chart recorder which timed the correct components. Review of results indicated all RPS circuits were found to be within the 50 msec requirement. The licensee planned to revise DIS 500-9 prior to utilizing the procedure for subsequent surveillance testing. The root cause of the event was attributed to inattention to detail of plant personnel in writing and conducting the surveillance procedure in regard to ensuring the proper applications of test equipment. The importance of attention to detail was emphasized to all plant personnel in licensee meetings conducted on February 26-27, 1991. The inspectors reviewed portions of the immediate corrective actions and sampled planned corrective actions to prevent reoccurence. Based on this review the inspectors considered the licensee's actions thorough and have no further concerns in this area.

(2) On February 8, 1991, an instrument maintenance staffer, while reviewing an instrument surveillance procedure in accordance with the Procedure Upgrade Program, identified that the procedure did not test the Standby Gas Treatment System (SGTS) heater interlock. This was identified during the licensee review which compared of electrical schematics to the procedure. The SGTS heaters ensured that the system humidity was not great enough to adversely affect system efficiency. The heater interlock automatically initiated the standby train upon failure of the heater in the operating train. Although the heaters were mentioned and credited in the Updated Final Safety Analysis Report (UFSAR), the existence of the heater interlock was not mentioned. Although the inspectors considered it important to periodically test this interlock, this was not considered to be a violation of NRC requirements due to the licensee's plant specific licensing basis. The licensee subsequently tested the interlock and verified it to function correctly. The inspectors regarded this as positive examples of the effectiveness of the Procedure Upgrade Program and the diligence and attention to detail exhibited by the individual performing the review.

One violation and no deviations were identified in this area.

5. Engineering/Technical Support (37828 and 93702)

a. The inspectors reviewed several recent plant modification packages. During this review, numerous concerns arose regarding the appropriateness of design input parameters and calculations for the Diesel Generator Cooling Water Pump Discharge Piping Modification (M12-2-90-18). As these concerns could indicate possible design control problems, this is considered an unresolved item (50-237/91003-02(DRP)) pending the licensee's response to these concerns.

b. On January 10, 1991, the licensee informed the resident inspectors of the results of a failure analysis performed on a Unit 2 reactor vessel head closure stud which had been replaced during a previous refueling outage in January 1989. At the time, inservice inspection ultrasonic testing had detected cracks in the lower threaded portion of two of the 92 head closure studs. The analysis concluded that the cracking was the result of stress corrosion possibly due to the exposure to oxygenated water during unit outages. In addition, the mechanical test results indicated that the stud material had a higher strength and lower toughness than reported in the original certification material test report. The cause of this discrepancy was postulated to be long term aging at operating temperature. Specifics of the technical aspects were reviewed and resolved between the licensee and the Office of Nuclear Reactor Regulation (NRR). The licensee attributed the two year delay in the analysis to problems with sample decontamination and higher priorities at the contract laboratory. It was apparent based on discussions with involved technical staff personnel that the licensee failed to pursue resolution in a timely manner and that this issue was considered to be the responsibility of the licensee's Systems Materials Analysis Department. The inspectors considered the delay excessive for such a potentially safety significant issue with possible generic applicability. This concern was discussed with the licensee at the exit interview.

c. On January 16, 1991, the licensee informed the resident inspectors of the discovery of an error in the Unit 3 Cycle 12 Reload Analysis dated August 1989, for the spent fuel storage pool reactivity. The licensee's contractor, Advanced Nuclear Fuels (ANF), had set a flag incorrectly in the computer code. The error was discovered while performing the analysis for the next cycle. The Cycle 12 analysis indicated that the peak assembly reactivity in a reactor lattice distribution would be less than the Technical Specification limit for k-inf of 1.27 for ANF 9 x 9 assemblies. Recent calculations showed the value to actually be 1.272, which was above the Technical Specification limit. The licensee indicated that the same error had not been made on any other previous or current reload analyses for either Units 2 or 3. The approximately 168 assemblies involved were in the spent fuel storage pool for 79 days prior to being loaded into the core in January 1990. The calculations for the 1985 amendment, which established the Technical Specification limit, actually concluded a k-inf limit of 1.277. The last digit had been truncated (purposely rounded in the conservative direction) in the amendment submittal, corresponding NRC safety evaluation report, and Technical Specifications. As the value from the original calculations could be verified, a review by the Office of Nuclear Reactor Regulation (NRR) indicated that this was not considered to be a violation of Technical Specifications. However, the inspectors were concerned with the degree of licensee oversight regarding ANF and consider this an open item (50-237/91003-03(DRP)) pending further review of this area including the cause of the error and corrective actions.

No violations or deviations were identified in this area.

6. Safety Assessment/Quality Verification (35502)

The inspectors reviewed the licensee's usage of the quality control feedback sheets which were prescribed in an internal departmental memorandum to address identified concerns that were of lower significance than required by more formal mechanisms and the Quality Assurance Manual. The inspectors regarded this process to be effective and beneficial with respect to enhancing the quality oversight of programs. It reflected the unilateral initiative of the quality control organization to go beyond the plant and regulatory requirements in the pursuit of problem identification and resolution.

No violations or deviations were identified in this area.

7. Safety Assessment/Quality Verification (35502)

NUREG 1403, "Safety Evaluation Report related to the full-term operating license for Dresden Nuclear Power Station," Table 2.1 identified SEP Integrity Plant Safety Assessment Report (IPSAR) topic resolutions to be confirmed by the NRC Region III office. The following items in that report were confirmed as closed by the inspectors:

Item 17 - Topic VI-4, 4.18.2 and 2.10 (Supp. 1)
Item 20 - Topic VII-1.A, 4.24.1 and 2.13.1 (Supp. 1)
Item 21 - Topic VII-1.A, 4.24.2 and 2.13.2 (Supp. 1)

No violations or deviations were identified in this area.

8. TMI Action Plan Requirements Followup (2515/065-01)

(Closed) TMI Item II.F.1.2.F (Units 2 and 3): This item required addition of drywell post-accident hydrogen monitoring instrumentation. The inspectors verified the existence of this instrumentation. TMI Item II.F.1.2.F (Units 2 and 3) is closed.

No violations or deviations were identified in this area.

9. Report Review

During the inspection period, the inspector reviewed the licensee's Monthly Operating Report for December 1990. The inspector confirmed that the information provided met the requirements of Technical Specification 6.6.A.3 and Regulatory Guide 1.16.

10. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether it is an acceptable item, an open item, a deviation or a violation. Unresolved items disclosed during this inspection are discussed in Paragraph 5.a.

11. 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. Open items disclosed during the inspection are discussed in Paragraph 5.c.

12. <u>Exit Interview</u>

The inspectors met with licensee representatives (denoted in Paragraph 1) on February 15, 1991, and informally throughout the inspection period, and summarized the scope and findings of the inspection activities.

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