U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Commonwealth Edison Company
Facility:	Dresden Nuclear Station Units 1, 2 and 3
Location:	Opus West III 1400 Opus Place - Suite 300 Downers Grove, IL 60515
Dates:	September 1 through October 18, 1996
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EXECUTIVE SUMMARY

Dresden Nuclear Station Units 1, 2 and 3
NRC Inspection Report 50-10/96013; 50-237/96013; 50-249/96013

This routine resident inspection included assessments of licensee operational, maintenance, engineering, and plant support activities. These inspections were conducted through direct observations in the field, documentation reviews, and discussions with station personnel.

Operations

- The facility was operated in a safe manner with good communication. Minor discrepancies continue to occur and operations personnel need to remain focused on attention-to-detail type issues (Section O1.1).

- Unit 3 Drywell closeout inspection. Two items identified by tha inspector delayed Unit 3 startup (Section O2.1).

- Operator properly respond to the annual "Grizzard Shad" fish migration which challenged the facility's service water system (Section O4.1).

Maintenance

- Restorative work for leaking control rod drive valve was well planned and executed. However, original job planning and procurement weaknesses were identified (Section M2.1).

- Unit 3 high pressure coolant injection system material condition and configuration control problems effect surveillance performance (Section M2.2).

- Station's backlog of outstanding work and action requests recoded to remove most of the planned corrective work (Section M3.1).

Engineering

- Unit 3 local leak rate testing of inboard and outboard isolation valves resulted in the inability to maintain containment leakage within allowable limits (Section E2.1).

- Design Engineering response to isolation condenser support and feedwater anchor issues was good (Section E2.2)

- Emergency diesel generator fuel oil transfer pump discharge gauge found over-ranged for the third time. Poor root cause identification contributed to repetitive maintenance (Section E2.3).

- Unit 2/3 emergency diesel generator ventilation fan Unit 2 power supply breaker troubleshooting was poor (Section E2.4).

- The control room ventilation system was unable to maintain the required 1/8 inch water positive pressure inside the control room envelop (Section E2.5).

Plant Support

- The contaminated material control program improved since the discovery of approximately 450 uncontrolled, contaminated items in April 1995. However, the corrective actions for this problem have not all been fully implemented and continued improvement in this area is needed (Section R1.1).

- Repairs to the station's east fire-main header did not recognize slip joint piping fit which resulted in flooding and increased work scope (Section F2.1).

REPORT DETAILS

Summary of Plant Status

Unit 2 was in a power ascension at the beginning of this report period and achieved effective full power (98 percent) on September 23. The unit continued at full power for the remainder of the report period.

Unit 3 began this period in Cold Shutdown as the licensee completed work on 4kV breakers and cubicles. Criticality was achieved on September 22, and effective full power (83 percent) was reached shortly thereafter. The unit was coasting down in power in preparation for the 1997 refueling outage (D3R14).

I. OPERATIONS

O1 Conduct of Operations

O1.1 Routine Observations (Units 2 and 3)

a. Inspection Scope (71707)

Routine day-to-day facility operations were observed and the inspectors attended various licensee planning and scheduling meetings. Additionally, the Unit 3 Startup Plan was reviewed and direct observations of control room and plant activities were performed on a shiftly basis during the ensuing start up.

b. Observations and Findings

Generally, the facility was operated in a conservative manner maintaining the reactors in a safe condition consistent with the licenses. The Operations Department did a good job controlling the start of station work by using the work execution center (WEC) to screen all work before authorization by the unit supervisor (US). This minimized the number of non-operating personnel in the control room and decreased the administrative burden on the US. However, some attention-to-detail discrepancies were identified in the control room during this period.

On a few occasions the inspectors noted a decline in the decorum and use of 3-way communications in the control room. This observation was discussed with licensee management. The licensee had also noted the decline in performance and were in the process of addressing it. In addition, several annunciators were in the alarm condition which was not consistent with current plant conditions. Further inspection identified that the on-shift nuclear station operator (NSO) had not reset the alarms to clear the annunciators. On all occasions the NSO knew why the alarm had come in and cleared it immediately.

On several occasions, the inspectors discovered one or more average power range monitor high level alarms illuminated on the main control board backpanel. These

alarm conditions were brought to the attention of the NSO and were also immediately reset. Note that the presence of the backpanel alarm would not have prevented the main control board frontpanel annunciator from alarming. After a review of documentation and discussions with cognizant personnel, it was determined that the alarm conditions were the result of a "burn-in" function of new local power range monitors (LPRMs). The alarm conditions were also of such short duration that the signal spikes from LPRMs caused the more responsive back-panel instrumentation to alarm without the corresponding audible and visible front-panel alarm. The NSOs indicated that there was no formal guidance on what to do when a backpanel alarm was discovered without a corresponding front-panel alarm. This was discussed with licensee management and was being reviewed by the licensee for corrective actions at the end of the report period. Since discussing these issues with the licensee, the inspectors have noted an increased awareness of these alarms by the NSOs.

c. Conclusions

The facility was operated in a safe manner with good communications. Minor discrepancies and attention-to-detail type issues were observed.

O2 Operational Status of Facilities and Equipment

O2.1 Drywell Closeout (Unit 3)

a. Inspection Scope (71707)

On September 20, the inspectors performed a "closeout" inspection of the Unit 3 drywell. This included a detailed tour of the drywell inspecting for operability, material condition, insulation, and housekeeping deficiencies.

b. Observation and Findings

Preparations and briefings for the drywell entry were detailed and well controlled by the Radiation Protection (RP) Department. Specific confined space training was performed and documented to ensure personnel entering the drywell were properly qualified. No deficiencies were noted with the radiation work permit or any other activities involving drywell entry.

During the tour, the inspectors identified two condensing chambers for the isolation condenser high steam flow isolation signal that were covered with insulation. The chambers had been inadvertently insulated during the outage. Condensing chambers need to be exposed to ambient condition so steam can readily condense and fill the lines of the attached instrumentation. By insulating the condensing chambers, the condensation of the steam was inhibited and could have effected the proper operation of the instrumentation. The insulation that was used was not the loose fibrous material that had been found in the past but was of a blanket type, appropriate for use in the drywell. The identified insulation was removed and the inspectors had no further concerns with this issue.

The inspectors identified a disconnected spring hanger during the tour. The hanger supported a reactor building closed cooling water (RBCCW) line going to the 3B reactor recirculation pump. The licensee made the necessary repairs to the hanger prior to startup, correcting all concerns with this issue.

There were several smaller housekeeping items such as tie-wraps, screws, and pieces of tape that were found by the inspectors which the licensee promptly retrieved and disposed of completing the closeout inspection.

c. Conclusions

The RP Department did a good job of controlling entry to the Unit 3 drywell. The drywell was generally clean, orderly, and contained no significant loose material. Although the actions necessary to correct the concerns noted above delayed startup, the drywell was in better condition than on previous "closeout" inspections.

O4 Operator Knowledge and Performance

O4.1 Service Water Strainer High Pressure Due To Fish Migration (Units 2 and 3)

a. Inspection Scope (71707)

Operator actions were observed in the control room and the inspectors toured the cribhouse and portions of the affected systems. A review of the licensee's prompt investigation of the event was also performed.

b. Observations and Findings

Beginning September 27, the annual week-long "Grizzard Shad" run occurred at the station. The shad are small sardine-like fish that migrate in large schools up the cooling channels in the fall. Last year's shad run resulted in a manual reactor trip of Unit 3 due to an anticipated loss of circulating water. This year the traveling screens were able to handle most of the shad; however, some carry-over of fish occurred due to an inadequate screen wash spray pattern.

On September 30, the NSO noticed a decrease in the service water system pressure. A non-licensed operator (NLO) dispatched to the cribhouse found all three service water stainer differential pressure gauges pegged upscale (greater than 5 psid). The shad carry-over had entered the service water system, plugging the strainers and causing a reduction in system pressure. The strainers automatic backwash function was in the manual mode instead of the automatic mode and was not able to perform an automatic backwash of the strainers. At about 0600 the licensee initiated a power reduction on both units while simultaneously commencing manual backwash operations. By 1100 the strainers differential pressure and the service water system pressure were restored to normal.

The licensee initiated a prompt investigation into the event and identified a number of deficiencies. The inspectors reviewed the licensee's investigation and concluded it was thorough. Several immediate and long-term corrective action were established which appeared adequate to mitigate future occurrences of the annual shad runs.

c. Conclusion

Work completed on the travelling screens to enhance the performance after last year's shad run was successful. With the travelling screens working properly other deficiencies were now evident including:

- Service water strainers backwash function in manual instead of automatic mode (an operator workaround).
- Inadequate travelling screen wash nozzle spray pattern allowing for some fish carry-over which entered the service water system.
- The lack of an abnormal operating procedure for dealing with the annual shad run.

Operators reacted in a controlled and conservative manner which minimized the transient on the facility. The prompt investigation was thorough and corrective action appeared adequate to reduce future vulnerability to the annual shad run.

O8 Miscellaneous Operations Issues (92701)

O8.1 (Closed) IFI 50-237;249/96009-02: Posted Procedures. On August 2, 1996, the inspectors identified a "posted procedure" in the power block which was not the most current revision. The procedure had been revised on July 29, and the copies in the main control room, WEC, and other required areas were the correct revision. Subsequently, the inspectors reviewed how posted procedures were controlled. It was noted that Dresden Administrative Procedure (DAP) 09-02, "Procedure Revision and Processing," Revisions 41 and 44, had not required posted procedures to be immediately updated. However, DAP 09-02 had required immediate update of main control room, WEC, and other non-posted procedures. Procedure DAP 09-01, "Station Procedures," Revisions 28 and 29, described how posted procedures were updated, but had not specified timeliness requirements. The licensee's corrective actions included changing the distribution list in procedure DAP 09-01 to add "posted procedures."

The inspectors reviewed the performance improvement form (PIF) data base for the past year and only identified a couple of other examples of incorrect revisions of "posted procedures." The licensee's corrective actions appeared adequate to prevent recurrence. This item is closed.

II. Maintenance

M1 Conduct of Surveillance

M1.1 Operators Performance During Execution of Surveillance (Units 2 and 3)

a. Inspection Scope (61726/71707)

Operator performance was observed and documentation reviewed for the following surveillance tests:

- Dresden Operating Surveillance (DOS) 1400-01, "Core Spray System Pump Test with Torus Available," Revision 20.
- DOS 1400-02, "Core Spray System Valve Operability Check," Revision 13.
- DOS 1400-04, "Core Spray Check Valves Inservice Test (IST) and Piping Flush," Revision 12.
- DOS 1500-02,"Containment Cooling Service Water Pump Test and Inservice Test (IST)," Revision 23.
- DOS 1500-05, "Low Pressure Coolant Injection (LPCI) System Quarterly Flow Rate Test," Revision 18.
- DOS 1500-10, "LPCI System Pump Operability Test with Torus Available and In-Service Test (IST) Program," Revision 24.
- DOS 6600-01, "Diesel Generator Surveillance Tests," Revision 40.

The inspectors also reviewed the diesel generator surveillance tests performed in using DOS 6600-01 that were completed due to a minor fire in the motor control center for the Unit 2/3 diesel generator ventilation fan (see Paragraph E4.1).

b. Observations and Findings

For the surveillances observed, operators performing the surveillances followed the appropriate procedures, completed all tasks, and were knowledgeable of Technical Specification requirements. Good communication practices were used throughout testing and operators responded correctly to discrepant conditions which were encountered. For example, during the performance of DOS 6600-01, "Diesel Generator Surveillance Tests," on October 15, the operators correctly declared Unit 3 emergency diesel generator (EDG) inoperable due to excessive coolant discovered in the EDG's air box.

c. Conclusions

The operators correctly followed the surveillance procedures. The operators were knowledgeable of the systems and took appropriate actions when unexpected results occurred. No significant deficiencies were identified.

M2 Maintenance Material Condition of Facility and Equipment

M2.1 Replacement and Repair of the 3A Control Rod Drive (CRD) Pump Discharge Valve (Unit 3)

a. Inspection Scope (62707)

The inspectors observed in-field activities associated with the replacement of the 3A CRD discharge valve and subsequent rework. A review of the work package and associated documentation was also performed.

b. Observations and Findings

The 3A CRD pump inboard seal exhibited leakage at an increasing rate and a decision was made to isolate the pump and repair the seal. The 3A CRD pump discharge valve (3-301-1A) would not provide an isolation boundary and a decision was made to replace the non-safety related valve. On September 25, about 1-week after the repairs, an operator noticed a pin-hole leak in the body of the replaced valve.

Inspection of the defective valve body showed a sand inclusion in the body which communicated with the outer valve body wall through a single pin-hole flaw. Radiographs showed that the sand inclusion was fed by several tiny fissures extending from the inner valve body wall to the inclusion. The radiographs also showed additional fishhook shaped fissures on either side of the sand inclusion which made several repair options impossible.

The initial corrective actions involved an attempt to establish a freeze-seal boundary to allow for valve replacement. This failed and the licensee decided to encapsulate the entire discharge valve. The encapsulation vessel exceeded the pressure rating of the system and after testing allowed continued facility operation. Radiographs were performed on all welds and a separate support bracket assembly was designed and installed to carry the extra weight. There were seven PIFs written to document the breakdowns in engineering, maintenance, work control, procurement, and quality control for the original replacement.

c. Conclusions

The licensee's actions following the identification of the pin-hole leak were conservative and well planned. Those actions recognized the work processes which failed to prevent the use of the defective valve body. The inspectors determined that the problems were limited to non-safety related work items. The interim repair was well engineered and a permanent repair will be performed at the earliest opportunity.

M2.2 High Pressure Coolant Injection (HPCI) System Problems (Unit 3)

a. Inspection Scope (61726/71707)

Portions of the HPCI system operability surveillance were obs[illegible]ed from the control room and a review of the licensee's troubl[illegible]shooting efforts were completed by the inspectors.

b. Observations and Findings

During the performance of the monthly Unit 3 HPCI system operability surveillance on October 2, one of the four HPCI room temperature monitors alarmed in the control room. Loca[illegible] room temperature readings for that monitor indicated a temperature of 122°F had been reached. The monitor that alarmed was located near the turbine steam chest and the instrument probe was discovered to be in contact with the turbine steam chest insulation. The other three room temperature sensors were reading about 95°F which made the general room ambient temperature well below the 120°F alarm setting. Because the procedure required the HPCI system be declared inoperable when any one of these sensors alarmed, the licensee declared HPCI inoperable.

The licensee's evaluation determined that the intent of the room temperature monitors was to determine the general room ambient temperature not a loc[illegible]ized temperature. Also, the location of the alarming monitor, in contact with th[illegible] insulation, was not a true measure of ambient room air temperature. Therefore, the procedure was revised to use the average of all four temperature detector reading as the basis for determining operability. Additionally, the licensee initiated a work request (WR) to have the alarming probe moved away from the turbine chest insulation. On October 4, the Unit 3 HPCI was declared operable.

During the test other problems were identified with the operation of the HPCI auxiliary and emergency oil pumps (AOP & EOP). The AOP automatically secured after the attached main oil pump achieved a pressure greater than 75 psig. This was unanticipated because the NSOs previous experience had been that the AOP continued running throughout the surveillance. The licensee's investigation determined that a 1992 AOP oil pressure trip set-point change, which raised the pressure switch setting from 75 psig to 95 psig, was completed on Unit 2 but not on Unit 3. This change was to prevent the AOP (a 40 Hp dc motor) from drawing repetitive starting current loads from the station's safety related 250 Vdc battery.

The investigation also determined that the Unit 3 switch was last calibrated on September 13 with an as-found setting of 86 psig. The switch was reset to 75 psig. While reviewing the calibration data it was determined that the as-found value of 86 psig was apparently high enough to preclude the AOP from tripping during previous surveillance tests. Until this year, neither unit's AOP oil trip pressure switch had

been in the calibration program. For corrective action the licensee made the appropriate changes to the calibration procedure and recalibrated the switch to 95 psig.

Unrelated to the AOP pressure switch problems, the EOP failed to start when the operator turned the manual EOP start switch in the control room after the AOP unexpectedly stopped during the test. Later the EOP also failed to start locally in the HPCI pump room. Troubleshooting determined that the secondary contacts in the circuit breaker were dirty and had caused the failure. A WR was initiated to have the breaker's contacts cleaned and the breaker was successfully tested and returned to service. At no time during the performance of this testing did the Unit 3 HPCI turbine lose lubricating or control oil because the main oil pump operated properly. Additionally, the AOP was available if pressure had fallen below 75 psig.

c. Conclusions

Operations personnel properly responded to the HPCI system performance and correctly declared the system inoperable based on the guidance in place at the time of the test. System engineering's review of the problems identified during the test was good and all difficulties were corrected in an expeditious manner. Although the specific problems were of minor safety consequence, the problems were indicators of longstanding issues such as material condition, coordination of setpoints between units, configuration control, electrical maintenance practices, and procedural adequacy.

M.3 Maintenance Procedures and Documentation

M3.1 Status of Maintenance Work Backlog (Units 2 and 3)

a. Inspection Scope (62707)

The inspectors reviewed the past and current data tables for action requests (ARs) and work requests (WRs) both for outage and non-outage, planned and corrective backlogs. Discussions were conducted with cognizant licensee personnel associated with managing these backlogs.

b. Observations and Findings

While reviewing tabular data from March 27, through September 13, 1996, the inspectors noted significant changes in some of the data. These changes occurred in June and included the following:

- Non-outage planned WRs dropped from a previously consistent level of 966 to a new level of 406, a decrease of 560 WRs.
- Outage planned WRs dropped from a previously consistent level of 1065 to a new level of 49, a decrease of 1016 WRs.
- Minor maintenance ARs awaiting approval dropped from a previously decreasing level of 43 to a new level of 1, a decrease of 42 ARs.

- Facility WRs increased from a previously consistent level of 528 to a new level of 650, an increase of 122 WRs.

The inspectors were told that the changes were intended to reduce the number of planned WRs. The WRs with the job code "planned" (PL) were recoded to "periodic" (PE) or facility maintenance depending on the tasks involved. The licensee stated that there was a directed effort not to recode jobs as corrective because that was a sensitive number but to leave them coded as PL and work them off. The final plan was to work off all WRs coded as PL and start coding new items as corrective from June forward.

c. Conclusions

Recoding of items in the maintenance work backlog has occurred several times during the past 2 years. Each time this has been done the true backlog picture gets a little clearer. This latest recoding may establish a better standard for categorizing backlog items.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Containment Leak Rate Limit Exceeded (Unit 3)

a. Inspection Scope (37551)

Follow-up of the postulated radiological dose consequences due to an as-found leakage pathway from the Unit 3 inboard and outboard main steam line (MSL) drain primary containment isolation valves. License Event Report (LER) 50-249/95007, Revisions 0, 1, and 2, "Leakage Limit Exceeded Due to Valve Internal Damage Caused by Manual Operation of Motor Operated Valve," were reviewed during the inspection.

b. Observations and Findings

In June 1995, the licensee determined that the Unit 3 inboard and outboard MSL drain primary containment isolation valves were leaking greater than the licensee's local leak rate test (LLRT) test equipment could measure. License Event Report 50-249/95007 was issued because when the as-found leakage was added to the existing maximum and minimum pathway leakage rates, the total containment leakage limit for Type B and C testing exceeded 0.6 La (488 standard cubic feet per hour (SCFH)). The significance of this event was previously considered an Unresolved Item (URI 50-237;249/95010-02) pending the licensee's assessment of the potential radiological consequences of the as-found leakage pathway.

Brief Background Information

During Unit 3 refueling outage 13 (March - November 1994), the existing MSL drain valves were replaced with 2 inch Anchor Darling double disk gate valves as part of the licensee's response to Generic Letter 89-10. In January 1995, the inboard valve was declared inoperable due to valve position indication problems. Both the inboard and outboard valves were shut from the control room to comply with Technical Specifications. On May 28, 1995, Unit 3 entered a forced outage. In June 1995 the inboard MSL drain valve was inspected, and the valve's position limit switches were engaged and the valve appeared closed. A LLRT was performed on the MSL drain valves and the "as-found" leakage for each of the valves was greater than test equipment could measure.

The cause for the inboard valve leakage was low spots on the valve's seat due to poor alignment (i.e., fit up) of the disk to seat. The root cause appeared to be poor maintenance instructions for valve assembly and lack of licensee experience with Anchor Darling double disk gate valves. The cause for the outboard valve leakage was the valve disk's lower wedge was missing and the stem was bent. The licensee determined that the failure mechanism of the outboard valve was excessive thrust applied during manual handwheel operation during Unit 3 refueling outage 13. The root cause was attributed to an inadequate design modification review in June 1994 that failed to identify that low torque values (about 33 ft-lbs) would damage the valve during normal handwheel operation. A contributing cause was informal controls for manual handwheel operation of motor operated valves.

The outboard valve was replaced with a "like-for-like" valve and the inboard was repaired. The as-left LLRT results were acceptable (see Inspection Report 50-237;249/95010, dated November 2, 1995).

Radiological Consequences

Based on the leakage from the MSL drain valves and from other primary containment isolation valves (described in the LER 50-249/95007), the licensee assessed the potential radiological consequences of the leakage in the event of the design basis accident. Assuming the worst case break of the Unit 3 MSL drain piping in the turbine building, preliminary calculations were performed using the "minimum pathway" leakage for the Unit 3 primary containment. The licensee concluded that during the design bases accident:

- The dose to the control room operators established by General Design Criteria (GDC) 19 of 10 CFR Part 50, Appendix A, would have been exceeded.

- The Exclusion Area Boundary and Low Population Zone dose limits established by 10 CFR Part 100 would have been exceeded.

The licensee performed a "realistic" assessment of the radiological consequences of a loss of coolant accident (LOCA) and concluded that the control room and offsite

doses were lower than those calculated using regulatory guidance. The licensee stated in LER 50-249/95007, Revision 2, that when the realistic Unit 3 MSL drain leakage values were combined with the Unit 3 realistic containment leakage component of the post-LOCA releases, the thyroid and whole body doses were less than the applicable limits in 10 CFR Part 100 and Part 50, Appendix A, GDC-19.

The licensee assessed the potential radiological consequences of the leakage from the other primary containment isolation valves and concluded that limits in 10 CFR Part 100 would not have been exceeded.

c. Conclusions

The licensee's root cause evaluation for the failures of the MSL drain valves was methodical and thorough, and the corrective actions were comprehensive (see Inspection Report 50-237;249/95010). However, based on the "as-found" condition of the MSL drain valves in June 1995, the valves were unable to maintain primary containment integrity since at least January 1995.

Technical Specification 3.7.A.2 required that primary containment integrity be maintained at all times when the reactor is critical. Technical Specification 3.7.A.2.b (2)(a) stated that when primary containment integrity was required, primary containment leakage shall be limited to a combined leakage rate of less than or equal to 0.6 La for all testable penetrations and isolation valves subject to Type B and C tests.

From at least January 1995 to May 28, 1995, with the U-3 reactor critical, primary containment leakage was greater than 0.6 La due to leakage past the inboard and outboard MSL drain primary containment isolation valves. The inboard and outboard MSL drain isolation valves are subject to Type B and C tests. Failure to maintain primary containment leakage less than or equal 0.6 La is an Apparent Violation of Technical Specification 3.7.A.2 (50-249/96013-01)

The apparent violation is being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600. Accordingly, no Notice of Violation is presently being issued for this inspection finding. Since the circumstances surrounding the apparent violation, the significance of the issue, and corrective actions were discussed with the licensee in the exit meeting for this inspection period on October 17, 1996, a pre-decisional enforcement conference may not be necessary in order to enable the NRC to make an enforcement decision. Before the NRC makes its enforcement decision, the licensee will be provided an opportunity to either respond to the apparent violation or request a pre-decisional enforcement conference, as described in the cover letter to this report.

E2.2 Isolation Condenser Supports (Units 2 and 3)

a. Inspection Scope (37551)

The inspectors performed a visual verification of the structures supporting the Unit 2 and 3 isolation condensers and several feedwater pump recirculation lines. Licensee responses and documents were also reviewed included:

- Mechanical Drawing M609C, sht 1 of 4, Condensate Booster Piping.
- Mechanical Drawing M609C, sht 2 of 4, Condensate Booster Piping.
- Mechanical Drawing M609C, sht 3 of 4, Condensate Booster Piping.
- Mechanical Drawing M609C, sht 4 of 4, Condensate Booster Piping.
- Mechanical Drawing M609R, sht 10 of 14, Condensate Booster Piping.
- Mechanical Drawing M1163D-553, Hanger Mark No. M-1163D-553.
- Mechanical Drawing M1163D-554, Hanger Mark No. M-1163D-554.
- Mechanical Drawing M1163D-555, Hanger Mark No. M-1163D-555.
- Phillips Drill Company Anchoring System Technical Manual.
- letter No. 0005201396, "Resolution of Isolation Condenser 2-1302 and 3-1302 Anchorage Issues," dated 10/08/96

b. Observations and Findings

The inspectors identified differences in the anchorage for the Unit 2 and Unit 3 isolation condensers. Design engineering evaluated these and determined that the differences were acceptable and would not have effected the safety function of the Isolation Condenser. The licensee initiated changes to two drawings to reflect the as-built plant.

While performing a routine plant tour, the inspectors noticed a whip restraint on the condensate booster piping going to the Unit 2 Reactor Feedwater Pump room that had anchor bolts which were tack welded to the base plates. This condition was immediately brought to the attention of the condensate system engineer and a request for further information was made.

During resolution of the identified issues, the licensee found additional discrepancies including some related to calculation of loads and seismic accelerations. The licensee had calculations performed to assess the discrepancies and determined that the existing isolation condenser supports were acceptable.

c. Conclusions

The drawings did not reflect the actual support configuration of the isolation condensers or the feedwater restraints. However, the licensee's response to the inspectors' concerns was thorough, as demonstrated by their identification and resolution of additional discrepancies.

E2.3 Emergency Diesel Generator (EDG) Fuel Oil Transfer Pump (Unit 3)

a. Inspection Scope (37551)

The inspectors toured the Unit 2, 3 and 2/3 EDG rooms observing general housekeeping and material conditions.

b. Observations and Findings

On September 1 the inspectors noted that the Unit 3 EDG fuel oil transfer pump discharge gauge, PI-3-5241-1, was over-ranged. Normal range on the gauge with the pump secured was 4 psig. The 0 to 15 psig gauge was found reading greater than 15 psig. This condition had been identified by the inspectors on three occasions over the previous 8 months. The failed gauge was again reported to the WEC for corrective action.

The gauge was used to verify pressure of the EDG fuel oil transfer pump during EDG day tank and diesel fire pump day tank filling operations. The gauge was not required for emergency operation of the EDG. A review of work documents indicated that the gauge had been replaced at least three times since March 1995 without a root cause for the failure having been performed. The system engineer believed that the latest occurrence of the over-ranging of the gauge was due to early closing of a solenoid valve in the pump discharge pipe which occurred during Unit 2/3 diesel fire pump day tank filling operation. At the close of the report period, the licensee was in the process of performing additional testing to determine the root cause of this failure.

c. Conclusions

Corrective actions to repair the Unit 3 EDG fuel oil transfer pump discharge pressure gauge have been inadequate. Although this problem only delayed surveillance testing of the EDGs, it impacted the operator's ability to ensure the pump was functioning properly when operated. The repetitive nature of the gauge failure demonstrated the difficulty the licensee has in resolving seemingly minor problems (i.e., replace the gauge vice identify and fix the root cause).

E3 Engineering Procedures and Documentation

E3.1 Updated Final Safety Analysis Report (UFSAR) Discrepancies

a. Inspection Scope (71707)

The inspectors used the UFSAR as a technical reference for section M1.1, "Operators Performance During Execution of Surveillance," of this report. A comparison of actual plant operation and configuration was made to the descriptions contained in the UFSAR.

b. Observations and Findings

Plant operations described in the Dresden Operations Surveillance (DOS) were compared to the UFSAR. One example was identified where the description in the UFSAR was not clear. Section 9.5.6, "Diesel Generator Air Starting System," stated, "Two air compressors maintain the air start receiver pressure at 250 psig." The inspector noted that DOS 6600-01, "Diesel Generator Surveillance Tests," verified that the compressors start at 220 psig, not 250 psig. The licensee indicated that the UFSAR would be revised to read that the receiver pressure was maintained greater than or equal to 220 psig.

c. Conclusion

The above example showed that some discrepancies between plant operation and the UFSAR exist. However, the licensee was taking prompt actions to resolve the identified discrepancy.

E4 Engineering Staff Knowledge and Performance

E4.1 Unit 2/3 EDG Ventilation Fan Breaker (Unit 2)

a. Inspection Scope (37551)

The inspectors observed the licensee's response to a small fire on September 15 in the 480 volt breaker for the Unit 2 supply breaker to the Unit 2/3 EDG Ventilation Fan. Additional follow up, troubleshooting, and maintenance actions were also reviewed and observed.

b. Observations and Findings

On September 15 a small fire occurred in the 480 volt breaker for the Unit 2 supply to the Unit 2/3 EDG Ventilation Fan. The source of the fire was the control power transformer in the breaker. During a subsequent start of the Unit 2/3 EDG, after repairs to the breaker, the NSO observed that the ventilation fan was running from the Unit 3 feed. The Unit 2/3 breaker logic normally seeks power for the EDG auxiliaries from Unit 2. Further investigation identified that the relay controlling which unit supplies power to the ventilation fan was also burned out.

The "power seeking" relay, located in a control panel in the Unit 2/3 EDG room, was replaced. Engineering completed a point-to-point wiring verification of both the Unit 2 and Unit 3 feed breakers and the Unit 2/3 EDG control panel. An unauthorized electrical jumper was discovered in the Unit 3 breaker that connected 120 Vac to 125 Vdc alarm power. The electrical jumper was old and had, most likely, been installed during initial construction. The electrical jumper in the Unit 3 breaker had no effect on the correct operation of the breaker and was not related to the fire in the Unit 2 breaker. The remainder of the logic and electrical wiring was satisfactory.

c. Conclusions

The engineering department's root cause evaluation was weak. The initial root cause was considered to be simply a control transformer failure. Subsequently, the licensee determined that the failed power seeking relay overloaded the circuit and resulted in the control transformer failure. A thorough, point-to-point check of wiring and logic initially following the fire was not performed. Had that level of troubleshooting been performed, the additional problems could have been identified and corrected prior to retesting the EDG. This event demonstrated the licensee's difficulty in identifying root cause of equipment failures.

E2.4 Control Room Ventilation System Operability (Units 2 and 3)

a. Inspection Scope (37551)

The inspector observed the repair and sealing of the control room ventilation leakage and attended plant operations review committee (PORC) meetings where corrective actions were evaluated. The operability determination and other associated documentation were also reviewed.

b. Observations and Findings

In September 1996 the licensee was closing out an open 1989 modification for the Unit 1 to Unit 2/3 control room fire-wall. Upon entering the control room, the cognizant system engineer noted that there was no differential pressure between the control room and the outside hallway. This observation prompted the licensee to perform a test to determine the actual control room to outside air differential pressure.

On October 7 the licensee performed testing and determined that the system was unable to maintain the required +1/8 inch water-gauge pressure in the control room with respect to all adjacent areas. The control room ventilation system was declared inoperable and Dresden Administrative Technical Requirement (DATR) 3/4.6.1 was entered. The DATR required control room ventilation to be returned to operable within 14 days or be in a condition where secondary containment was not required (i.e., Cold Shutdown).

The control room ventilation system was declared "operable but degraded" on October 21 after significant on-site and corporate resources were expended. Many of the walls making up the control room envelop were stripped and leaks were identified and sealed. Numerous cable penetrations were identified as leaking and were also sealed. The auxiliary computer room was removed from the control room ventilation envelop with Temporary Alteration III-53-96. The inspectors will monitor the actions taken by the licensee as this issue continues to evolve. Due to the on-going inspection of this issue it is considered an Unresolved Item (URI 50-237;249/96013-02).

c. Conclusions

Initial licensee reactions were aggressive and comprehensive when the issue was finally understood. This issue was directly tied to a 1989 modification which changed the fire-walls between the Unit 1 and Unit 2/3 control rooms. Further evaluation will be necessary before final conclusions can be made.

IV. Plant Support

R1 Radiation Protection and Chemistry (RP&C) Controls

R1.1 Review of Radioactive Material Control Program

a. Inspection Scope (83750)

The inspectors observed RP technicians performing unconditional release surveys of material from radiologically protected areas (RPAs) and interviewed RP technicians and management regarding contaminated material control practices and policies.

b. Observations and Findings

Dresden Station identified approximately 450 uncontrolled contaminated items outside of radiologically posted areas (RPAs) in April 1995 during a site-wide survey. As documented in a June 2, 1995 letter, enforcement discretion was exercised for this issue by the NRC. This was based, in part, on immediate actions, such as the survey, to identify the full scope of the problem, and planned corrective actions to improve performance in this area. The inspector's review indicated mixed results from the corrective actions which were implemented subsequent to the discovery of the items.

Twenty seven corrective actions were developed to improve contaminated material control and improve radiation protection technician performance in general. On January 26, 1996, an effectiveness review of the corrective actions was completed and presented to the PORC. It essentially concluded that most of the corrective actions were ineffective or were not implemented as intended. A radioactive material committee was then established and the following new, primary corrective actions were developed: 1) eliminate the temptation to remove tools and materials into and/or out of the RPAs; 2) heighten worker's level of awareness; and 3) implement program accountability. A number of sub-items were specified for completion under each of the main actions.

Progress in implementing these corrective actions had been mixed. Color coding and accountability of tools to enhance workers' awareness of the contamination status of the items was well underway and was a positive step. A contaminated tool shop located in the Unit 1 turbine area provided a storage location for contaminated tools so that the number of clean tools needed to be brought into the RPA was limited. A hands-on material release training session for radiation protection technicians (RPTs) was conducted using slightly contaminated items.

This was well received by the RPTs and good practices were noted while RPTs were observed surveying potentially contaminated material for unconditional release at RPA exit points. A tool monitor was used for items that required unconditional release from the RPA.

Licensee management had intended to reduce the number of RPAs as part of the initial corrective actions for the material control problem. However, the number of "outside" RPAs remained essentially the same as in 1995. Although most were under lock and key, the inspectors noted that an RPA established in the electrical shop for 4 kV breaker work had evolved from an area with continuous RP coverage to one with virtually none. This had not provided much of a deterrent for moving material in and out of this RPA.

Approval of a RP supervisor was needed for items to be released from the RPA. However, all the current first-line supervisors were new to their positions within the past year. Although all had appropriate backgrounds from previous experience outside of ComEd, none had received Dresden-specific systems training. Given the significant amount of past cross contamination of normally uncontaminated systems at the station, this lack of knowledge could effect their ability to make a proper decision on whether or not an item should be released. During interviews, three different RPTs indicated that one of the supervisors recommended that an instrument air cooler, which would normally not be expected to be contaminated, be released even though all areas of the cooler could not be surveyed. Due to prior knowledge of the system, a RPT conducted thorough surveys subsequent to this recommendation and determined that the item was actually contaminated.

A further problem with this mechanism for releasing items was that only limited transfers of material in and out of the RPA was intended during the initial corrective actions. Although the restriction allowed for items to be unconditionally released from the RPA with supervisory approval, it was identified that numerous items were released at the exit point on a daily basis. Management acknowledged that this was not the intention of the original corrective action and that this policy would be reevaluated.

c. Conclusions

The contaminated material control program has improved since April 1995. However, corrective actions such as minimizing the number of "outside" RPAs and effectively controlling all outside RPAs have not been fully implemented. Continued improvement in the control of contaminated material was needed.

F3 Fire Protection Facilities and Equipment

F3.1 East Fire-main Header Break

a. Inspection Scope (71707) (Units 1, 2 and 3)

The inspectors toured the area of excavation, monitored work activities, and observed licensee discussions on potential causes and corrective actions.

b. Observations and Findings

On October 15 at 5:35 p.m. the Unit 2/3 diesel fire pump (DFP) started due to low system header pressure. At 5:40 p.m. a member of the station's Loss Prevention Group noted that the recently dug east fire-main trench was flooded. The licensee responded to the flooding by securing the Unit 1 DFP and extending the fire-main system out-of-service (OOS) isolation. The original OOS isolated only a portion of the east header to facilitate the removal of a short section of piping suspected of leakage. The extended boundary placed the Unit 1 crib house and site blackout diesel generator building inside the OOS. This new boundary made the Unit 1 DFP and the Unit 1 Screen Wash pump unavailable to serve as sources of firewater. Therefore, the site fire-main system was supplied by the Unit 2 and 3 service water system backed up by the Unit 2/3 DFP.

c. Conclusion

Poor job and OOS planning resulted in flooding and the ultimate extension of the east fire main out-of-service boundary. The planners did not take in to account the fact that slip joint piping was installed on the portion of the system that was being worked on. After the OOS was hung and the intended section of piping removed, the slip joint upstream of the isolation point gave way and resulted in the flooding. This event emphasized the continued need for focused attention on the preparation of OOS and work planning.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on October 17, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

S. Perry, Site Vice President, Dresden
E. Connell, Design Engineering Superintendent
T. Foster, Work Control and Outage Manager
R. Freeman, Plant Engineering Superintendent
J. Heffley, Units 2 and 3 Station Manager
C. Howland, Radiation Protection Manager
R. Kundalkar, Site Engineering Manager
T. Nauman, Unit 1 Station Manager
T. O'Connor, Operations Manager
F. Spangenburg, Regulatory Assurance Manager
P. Swafford, Unit 2/3 Maintenance Superintendent
P. Tzomes, Support Services Director
D. Winchester, Safety Quality Verification Director

INSPECTION PROCEDURES USED

IP 37551: On-site Engineering
IP 62707: Maintenance Observations
IP 64704: Fire Protection Program
IP 71707: Plant Operations
IP 92901: Followup - Plant Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-249/96013-01	VIO	Failed LLRT (Apparent Violation)
50-237;249/96013-02	URI	Control Room Ventilation

Closed

50-237;249/96009-02	IFI	Posted Procedures

Discussed

50-237;249/95010-02	URI	Assessment of the Potential Radiological Consequences of Failed LLRTs

LIST OF ACRONYMS USED

AOP	Auxiliary Oil Pump
AR	Action Request
CRD	Control Rod Drive
DAP	Dresden Administrative Procedure
DATR	Dresden Administrative Technical Requirements
DFP	Diesel Fire Pump
dc	Direct Current
DOS	Dresden Operations Surveillance
EDG	Emergency Diesel Generator
EOP	Emergency Oil Pump
HPCI	High Pressure Coolant Injection
IST	Inservice Test
Kw	Kilowatt
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LOCA	Loss Of Coolant Accident
LPCI	Low Pressure Coolant Injection
LPRM	Local Power Range Monitor
MSL	Main Steam Line
MW	Megawatt
NLO	Non-Licensed Operator
NSO	Nuclear Station Operator
OOS	Out Of Service
PE	Periodic
PIF	Performance Improvement Form
PL	Planned
PORC	Plant Operations Review Committee
psig	Pounds Square Inch Gauge
RBCCW	Reactor Building Closed Cooling Water
RP	Radiation Protection
RPT	Radiation Protection Technicians
RPA	Radiologically Protected Areas
SCFH	Standard Cubic Feet per Hour
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
US	Unit Supervisor
WEC	Work Execution Center
WR	Work Request