U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/91031(DRP); 50-249/91034(DRP)

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

Licensee: Commonwealth Edison Company

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

Inspection At: Dresden Site, Morris, IL

Inspection Conducted: October 20 through December 6, 1991

Inspectors: W. Rogers

D. Hills

M. Peck

R. Zuffa, Site Resident Engineer
Illinois Department of Nuclear Safety

Approved By: Mark A. Ra for B. L. Burgess, Chief
Projects Section 1B

12/24/91
Date

Inspection Summary

Inspection from October 20 through December 6, 1991 (Report Nos. 50-237/91031(DRP); 50-249/91034(DRP)).
Areas Inspected: Routine unannounced safety inspection, by the resident inspectors and an Illinois Department of Nuclear Safety inspector, of licensee action on previously identified items; licensee event report; operational safety; monthly maintenance; monthly surveillance; events followup; refueling activities; training effectiveness; regional requests; and management meetings.

Results: One unresolved and two open items were identified.

Plant Operations

Stronger procedural adherence was observed; however, operators attempted to work around problems as evidenced by the one reactor scram during the inspection period.

Maintenance/Surveillance

Some personnel errors were noted but were not widespread. Outage activities appeared to be adequately controlled.

Safety Assessment and Quality Verification

A lack of a questioning attitude by station personnel was apparent from the negative observations associated with battery room temperatures and drywell ventilation fan configuration. However, these observations were somewhat counterbalanced by the licensees identification of electrical cables between divisions not being physically separated.

DETAILS

1. Persons Contacted

Commonwealth Edison Company

*C. Schroeder, Station Manager
*L. Gerner, Technical Superintendent
*J. Kotowski, Production Superintendent
*D. Van Pelt, Assistant Superintendent - Maintenance
*G. Smith, Assistant Superintendent-Operations
*K. Peterman, Regulatory Assurance Supervisor
M. Korchynsky, Operating Engineer
B. Zank, Operating Engineer
T. Mohr, Operating Engineer
D. Ambler, Health Physics Services Supervisor
*D. Lowenstein, Regulatory Assurance Supervisor
K. Kociuba, Quality Assurance Superintendent
*T. Gallaher, Nuclear Quality Programs
*J. Gates, Technical Staff
*R. Stachniak, Performance Improvement Supervisor

*Denotes those attending the exit interview conducted on December 6, 1991, and at other times throughout the inspection period.

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 maintenance personnel; and contract security personnel.

2. Previously Identified Inspection Items (92701 and 92702)

a. (Open) Unresolved Item (50-237/90022-02(DRP)): Evaluate suitability of two specific calculational assumptions utilized in the licensee's November 3, 1987, control room habitability analysis. In a July 3, 1991, John A. Zwolinski to Charles E. Norelius memorandum, the Office of Nuclear Reactor Regulation confirmed the acceptability of the primary containment leakage value utilized by the licensee in the analysis. As this value was incorporated into the plant licensing basis through a May 11, 1983, NRC safety evaluation report, the inspector has no further concerns regarding this assumption. The remaining assumption in question, control room ventilation manual isolation and pressurization time, will be evaluated more fully during the next routine inspection period. This item will remain open until the NRC completes the evaluation of the second concern.

b. (Closed) Violation (50-237/90027-06(DRP)): Failure to make a required emergency notification system (ENS) telephone call. Subsequently, the required ENS call was made. A memorandum was issued to the operations department providing additional guidance on what constituted an engineered safety features actuation. However, this guidance was not clear enough and another violation, 50-237/91022-10(DRP), was issued for inadequate corrective action to this violation. Subsequent to issuance of the second violation, the licensee lowered their threshold for reportability, clarified guidance to the operations staff, and conducted additional training. Based on preliminary inspection review of these corrective actions, this item is closed.

c. (Open) Unresolved Item (50-237/91010-04(DRP)): Failure to place certain safety related containment isolation damper pressure switches in the calibration program. During the inspection period, the inspector followed up on the licensee's actions which included the recalibration of pressure switches associated with the containment isolation dampers in question.

During the recalibration process, the licensee reported that the as-found setpoint of four of the pressure switches requiring recalibration was approximately one-third of the required setpoint setting. At the end of the inspection period the licensee had not provided specific test results or engineering evaluations to conclude whether the isolation valves associated with these pressure switches would have had sufficient motive pressure within their closure mechanisms to move the valve to its required fail-safe condition. However, a deviation report had been written to address this concern. Upon conclusion of the licensee's evaluation this matter will be reviewed again.

No violations or deviations were identified in this area.

3. <u>Licensee Event Reports (LER) Followup (90712 and 92700)</u>

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

a. (Closed) LER 237/91005, Orderly Unit Shutdown Due to Leakage Through Primary Containment Isolation Valves AO

2-220-44 and AO 2-220-45. One action yet to be reviewed by the inspector involved the licensee's evaluation of a stiffer spring pressure for the two air operated valves. This matter, in addition to other long term actions associated with these valves discussed in LER 237/91015, is considered an open item (237/91031-01(DRP)).

b. (Closed) LER 237/91014, Primary Containment Isolation Valve Closure Due to Reactor Water Cleanup System Isolation.

c. (Closed) LER 237/91015, Orderly Unit Shutdown Due to Leakage Through Primary Containment Isolation Valves AO 2-220-44 and AO 2-220-45. Three corrective actions referenced in the LER were the evaluation for potential design changes for the air operated valves, completion of an engineering study to extend the safety related boundary, and modification of the mechanical maintenance procedure, DMP 0040-06. These three corrective actions in conjunction with the one corrective action from LER 237/91005 represent the open item referenced in sub-paragraph a. above.

d. (Closed) LER 237/91016, Spurious Closure of 2A SDC Pump Isolation Valve Due to Control Relay Contact Problem.

e. (Closed) LER 249/91008, Unplanned Primary Containment Group V Isolation Due to a Blown Fuse. The light was replaced and the containment isolation reset. At the end of the 30 day reporting deadline the licensee had yet to determine the root cause of the isolation and further inspections of the circuitry were scheduled. The licensee stated in the original LER that a supplemental report was expected to be submitted on January 31, 1992. Further followup of this event and the licensee's corrective actions will performed after the supplemental report is submitted.

f. (Open) LER 237/91017, Unplanned Primary Containment Isolation Valve Movement During Auxiliary Power Transfer Due to Deficient Relays.

On August 25, 1991, a turbine generator trip occurred at 38% power from the spurious activation of the thrust bearing wear detector relay. The trip occurred during the opening of the "B" recirculation loop discharge valve. The valve was being cycled to facilitate 120 VAC control power testing in response to a NRC degraded voltage concern. Subsequently, the licensee determined the thrust bearing housing had been installed without a shim causing the turbine generator trip.

Following the turbine trip and during the automatic fast bus transfer (less than 0.083 seconds) of plant electrical loads from the unit auxiliary transformer (UAT) to the reserve auxiliary transformer (RAT), several Group I and Group II primary containment isolation valves spuriously closed. The MSIVs did not close as the DC solenoid for these valves remained energized.

The isolation valves and AC solenoids are powered from the 120 VAC isolation bus. This bus is supplied from the 480/240/120 main instrument bus transformer through the 120/240 main instrument bus. During normal plant operation, the instrument bus source of power originates at the UAT down through the 4KV safety bus No. 23-1.

The fast bus transfer took place as designed. However, the inspectors are concerned that degraded voltage conditions are being experienced at the 120 VAC level. Station personnel informed the inspectors that the drop-out of the MSIV Group I AC solenoid valves was experienced as early as 1987 during fast bus transfers. The occurrence of other Group II valves spuriously closing has been increasing. Unit 3 experienced the spurious closure of several Group III isolation valves during a recent fast bus transfer.

A number of factors may be contributing to these spurious closures:

- The UAT is normally operated with a 2.5% voltage boost. This is to compensate for a heavier loaded UAT which is also supplying station house loads. A transfer to the RAT will connect bus No. 23-1 loads to a lower source voltage.

- Following the main turbine trip, an additional 1% drop in switchyard voltage is typically experienced.

- Since the RAT is not loaded as high as the UAT and its voltage is not boosted, the RAT may be experiencing a voltage transient that is greater than 0.083 seconds as it lags behind the fast bus transfer in picking up the UAT's loads.

- Load growth since original station design may have increased the burden on the auxiliary transformers, causing an increase in the voltage transient seen during a fast bus transfer.

- The main instrument transformer is unregulated.

- The normally energized, individual valves and solenoid seal-in control relays (General Electric 12HMA111B9) may be exhibiting increased sensitivity to degraded voltage as the relays age.

The licensee is implementing modification No. M12-2(3)-88-60 to replace twelve (12) Group I primary containment isolation system (PCIS) 12HMA111B9 relays with GE type 12HGA17S63 relays. This modification does not address replacing the HMA relays in the other isolation valve groups. The replacement relays should not change state during power losses of approximately 15 cycles (0.25 seconds) duration. The remaining two (2) Group I valves do not require a control relay replacement as they are normally closed and are motor operated.

The inspectors noted the modification appeared to address the symptoms instead of correcting the low voltage condition. The drop-out of the valve control relays appeared to be random and the spurious isolations appeared to be increasing, such as Group III isolations on Unit 3.

The inspectors also noted that the replacement HGA relays had different nameplate values regarding current closing ratings and current interrupting ratings than the HMA relays. The modification package did not provide a justification that the HGA relay contact ratings were acceptable as a HMA replacement in this application. In addition, the voltage and/or transient pulse width that would cause the HMA relay to drop-out is unknown. This information could be useful to support the use of the HGA relay.

The inspectors have the following questions for the licensee to address:

- When will the control relays for all of the isolation valves supplied by the 120 VAC isolation bus be replaced in both units?

- What is the minimum voltage and pulse width that will drop-out existing HMA relays?

- Are the HGA contact ratings an acceptable HMA replacement for this application?

- What training will be provided to the operators to prevent operational confusion when isolation valves spuriously close without a group isolation signal?

- What evaluation was performed to determine that relay replacement was the best alternative rather than providing a regulated supply to the isolation valve bus?

The above questions are considered to be an Open Item (50-237/91031-02(DRS)).

No violations or deviations were identified except as delineated in this or other reports.

4. Operational Safety Verification (71707)

The inspectors reviewed the facility for conformance with the license and regulatory requirements and that the licensee's management control system was carrying out its responsibilities for safe operation.

On a sampling basis the inspectors observed control room activities for proper control room staffing; coordination of plant activities; adherence to procedures or Technical Specifications; operator cognizance of plant parameters and alarms; electrical power configuration; and observed the frequency of plant and control room visits by station managers.

While in the control room various records (such as tagouts, jumpers, shift logs and surveillances, daily orders, maintenance items, and various chemistry and radiological sampling and analysis) were reviewed.

During tours of accessible areas of the plant, the inspectors made note of general plant and equipment conditions. General areas of review included engineered safety features system valve and electrical power alignments, radiation protection practices, security plan implementation, plant housekeeping or cleanliness, and control of field activities in progress.

a. The accessible portions of the engineered safety features systems listed below were inspected.

Unit 2

Emergency Diesel Generator system
2/3 Emergency Diesel Generator System
Core Spray System
Standby Liquid Control System
Service Water System

Unit 3

Isolation Condenser
Core Spray System
Standby Liquid Control System
Inboard/Outboard Main Steam Isolation Valves

b. On October 31, 1991, an inspector identified an operating temporary ventilation fan taking suction from a contaminated area on the 517 foot elevation of the Unit 3 reactor building and discharging into a clean area. Initially, the fan was set up to draw air from the Unit 3 drywell, process the air through a high efficiency particulate air filter and discharge the air into the reactor building. However, the duct work connecting the filter and the fan suction, located in a contaminated area, was disconnected. The licensee corrected the problem by reconnecting fan suction and decontaminating the area. A radiological occurrence report was initiated to track the corrective action and to evaluate the root cause of the problem.

c. During one of the building tours on November 4, 1991, an inspector identified the temperature in the 125 volt and 250 volt battery rooms had dropped to approximately 59 degrees fahrenheit (F). The Final Safety Analysis Report stated the 250 volt battery sizing was based on the lowest expected electrolyte temperature of 65 F and below this temperature the batteries may not have sufficient capacity to meet the load profiles. Following notification by the inspector, operations personnel declared the batteries inoperable and transferred the Unit 2 mode switch from refuel to shutdown as required by the Technical Specifications. The Unit 3 mode switch was already in the shutdown position. The licensee subsequently performed an engineering evaluation which concluded, based on remaining capacity, that the batteries could still perform their design basis function at temperatures down to 55 F. The failure of station personnel to identify the degraded temperature in the battery rooms during operator rounds will be addressed in a subsequent report.

No violations or deviations were identified in this area.

5. Monthly Maintenance Observation (62703)

Routinely, station maintenance activities were observed and/or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards and did not conflict with technical specifications.

The following items were also considered during this review: approvals were obtained prior to initiating the work; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; and activities were accomplished by qualified personnel.

The following maintenance activities were observed and reviewed:

<u>Unit 2</u>

Unit 2 Diesel Generator Turbo Charger Lube Oil Pump Replacement
Unit 2 Diesel Generator Cooling Water Three-way Valve Replacement
Unit 2 Amplidyne Voltage Regulator Replacement
2B Reactor Feed Pump Seal Replacement
Trouble shoot & repair of Intermediate Range Monitor spiking (WR D04901)

<u>Unit 3</u>

3A and B LPCI Heat Exchanger Tube Repair
3-1501-21A, LPCI Outboard Injection Isolation Valve Rebuild
3-2301-4, HPCI Inboard Steam Supply Isolation Valve Rebuild
Unit 3 Diesel Generator Turbo-Charger Removal/Inspection
Unit 3 Diesel Generator Main Bearing Replacement
#3 DG Cooling Water Pump Discharge Checkvalve Relocation
Unit 3 MSIV Air Operator Rebuild
In-Vessel Remote Inspections
Standby Liquid Control System Pump and Motor Rebuild
220-59B Feedwater Check Valve Rebuild
3-1501-22A, Diagnostic Volts Testing (WR D98864)
3-1601-33A, Torus to Drywell Vacuum Breaker Rebuild (WR D96782)
3-1601-32D, Torus to Drywell Vacuum Breaker Rebuild (WR D96743)
3-202-58, Feedwater Check Valve Rebuild
3-1501-26B, LPCI Manual Isolation Valve Rebuild
Outage related work for wetwell ventilation modification (WR D00815-02)

No violations or deviations were identified.

6. <u>Monthly Surveillance Observation (61726)</u>

The inspectors observed several of the surveillance tests required by Technical Specifications and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that results conformed with Technical Specifications and procedure requirements, and that any deficiencies identified during the testing were properly resolved.

The following surveillance activities were observed and reviewed:

Unit 2

DOS 2300-1 HPCI Motor-Operated Valve Operability Verification
DOS 2300-3 HPCI System Operability Verification
DOS 6600-1 Unit 2 Diesel Generator Monthly Operability Test
DOS 1400-5 Quarterly Core Spray System Flow Test
DOS 1500-2 Containment Cooling Service Water Pump Test
DOS 1500-4 LPCI System Quarterly Flow Rate Test
DOS 5600-2 Monthly and Weekly Turbine Checks
DTS 1600-22 Secondary Containment Leak Rate Test

Unit 3

DOS 6600-1 Unit 3 diesel Generator Monthly Operability Test
DTS 300-10 Control Rod Drive Functional Scram Valve Testing

No violations or deviations were identified.

7. Events Followup (93702)

a. In response to a recommendation from engineering the station performed a service test of the Unit 3, 250 volt battery on October 15, 1991. The battery failed to meet the minimum acceptance criteria voltage of 210 volts during the first minute of the test. At the conclusion of the test the battery was declared inoperable.

The Unit 3, 250 volt battery and associated charger supplied the Unit 3 turbine building non-safety 250 volt loads and the Unit 2 reactor building safety related loads. On October 18, 1991, the station submitted a request for a waiver of compliance of 250 volt battery Unit 2 Technical Specification (TS), TS 3.9.B.4.a, to the NRC. The intention of the waiver was to permit continued operation of Unit 2 by extending the limiting condition for operation seven additional days. The additional time provided for a more detailed evaluation of the battery load profile and retesting of the battery. The waiver of compliance was not approved by the NRC and Unit 2 was subsequently placed in cold shutdown on October 22, 1991. The licensee performed a second service test of the battery on October 27, 1991, which also resulted in the failure to meet the minimum voltage acceptance criteria.

From a review of the service test results the licensee concluded that the battery had insufficient capacity to meet the loading requirements of all postulated design bases events. To reduce the peak electrical battery load profile, the licensee added a 40 milli-second time delay relay to the high pressure coolant injection (HPCI) system logic to eliminate possible coincidental operation of the HPCI injection and test return valves while in the test mode. Prior to the restart of Unit 2 the licensee successfully performed a two minute service test on the new battery profile, revised operating procedures to delete the practice of manually starting the DC emergency bearing oil pump (EBOP) after a turbine trip, and added four more cells to both unit's batteries (M12-3-91-021) to increase margin. Additionally the licensee committed to install a separate non-safety related battery system to power each units main turbine EBOPs during the next Unit 2 and Unit 3 refueling outages.

b. While Unit 2 was shutdown the licensee determined that control rod drive P-10, which had a stuck collect piston in the previous routine inspection report period, should be removed. However, technical specifications did not allow the mode switch to be placed in REFUEL which would be necessary to facilitate removal of the control rod drive. After providing adequate justification the NRC granted a temporary waiver of compliance on the matter. An inspector observed drive removal activities with minimal problems noted.

c. While performing Alternate Rod Insertion (ARI) Scram Air Header Blowdown Timing Test on Unit 3 on November 3, 1991, the Channel B ARI solenoid valves failed to actuate when the pushbuttons were depressed. The licensee found a fuse cartridge in Bus 32 in the OFF position. Upon placing the cartridge in the correct position, ARI was successfully tested.

The licensee believed that the fuse cartridge was placed and left in the OFF position during Bus 32 refurbishment earlier in the refueling outage. Prior to commencing maintenance activities on Bus 32 all fuel was removed from the reactor core. At the time of the ARI test Bus 32 had not been fully returned to service and the final electrical lineup verifications had not been performed.

d. On November 26, 1991, a physical walkdown of a division II cable between Bus 29 and motor control center (MCC) 29-2 identified the cable was routed in a division I cable tray violating the division cable separation criteria. The walkdown was performed to support a potential modification between Bus 29 and MCC 29-2; replacing the existing cable with a larger cable to reduce the voltage drop. The proposed modification was in response to a NRC concern regarding the minimum voltage available to the Unit 2 diesel generator service water pump during degraded grid conditions. Utilizing a computer cable routing program and data base, the licensee identified that cable separation requirements were also not met on a Unit 2 MCC and two Unit 3 MCCs. This item is considered an unresolved item (237/91031-03(DRP)) pending further review by the NRC of the cable installation and the licensee's operability evaluation.

e. On November 13, 1991, Unit 2 scrammed during reactor startup activities. The initiating signal for the scram was high neutron power on the intermediate range channels. The high neutron power signal was caused by noise in the signal cables. Numerous noise problems had occurred since early November and were documented. The largest contributor to the noise spiking was the operation of selected direct current motor operated valves. Following the scram the licensee performed troubleshooting to determine which valves caused the problems and corrective actions were taken to reduce the spiking of the neutron monitoring system. Further examination of corrective actions associated with the noise reduction effort will be reviewed during LER followup of this event.

No violations or deviations were identified.

8. Refueling Activities (60701)

The inspector verified the licensee's compliance with license requirements and procedures commensurate with reactor core alteration refueling activities. Inspection activities included licensee's compliance with the procedures and surveillance as listed below.

- DFP 800-1 Master Refuel Procedure
- DAP 7-7 Conduct of Refueling Operations
- DOS 800-1 Refueling Interlock Check

The inspector also verified licensee's radiation protection measures involved with refueling activities and in vessel work prior to refueling activities.

The inspector also interviewed the licensee's work planning personnel in order to ascertain licensee's position on refuel outage activities and to verify projected completion dates and completion percentages of specific activities against the actual progress as witnessed in the plant.

No violations or deviations were identified in this area.

9. <u>Training Effectiveness (41400, 41701)</u>

The effectiveness of training programs for licensed and non-licensed personnel was reviewed by the inspectors during the witnessing of the licensee's performance of routine surveillance, maintenance, and operational activities and during the review of the licensee's response to events which occurred during the inspection period. Personnel appeared to be knowledgeable of the tasks being performed. However, equipment problems associated the noise in the intermediate range neutron monitoring system were indicative of licensed personnel working around problems versus assuring appropriate resolution.

No violations or deviations were identified.

10. <u>Regional Requests</u>

a. Following a request from regional management as to the type of Woodward governor utilized on the emergency diesel generators the inspectors confirmed that a mechanical governor was in service. Therefore, the NRC memorandum dated September 12, 1991, from the NRR Electrical Systems Branch Chief concerning electronic governors was not applicable to the Dresden Station.

b. In response to a regional management request on drywell equipment hatch information the inspector contacted the licensee's system engineer and received the applicable information.

c. Recognizing that training instructors were not in the training program with the intent of taking an operator license exam, the region questioned whether training instructors could operate reactor controls under the cognizance of a licensed reactor operator. Subsequently, the licensee was informed by NRC regional operator licensing branch that manipulation of reactor controls could only be done when the individual intended to take the exam. This position was reconfirmed by NRC headquarters on October 25, 1991.

d. Following a request from regional management the inspectors confirmed that the licensee's response to the national survey from the NRC/EPA on the mixed waste profile was completed in a timely manner.

11. Management Meetings (30702)

On November 12, 1991, NRC senior management met with CECo senior management at Region III Headquarters. The meeting agenda was to discuss the recent performance decline at the Dresden Station. Included in the discussion were root causes and corrective actions. During the meeting the licensee basically agreed with the NRC assessment of root causes associated with the decline. The licensee indicated that the Dresden Situational Review Team findings paralleled the NRC's assessment. The root causes concluded by the NRC were weaknesses in:

1) Procedure Adherence
2) Procedure Quality
3) Communications
4) Engineering and Licensing Support
5) Personnel Meeting Management's Expectations

The licensee discussed short term corrective actions to stop the performance decline with long term corrective actions to be established during the first quarter of 1992.

12. Unresolved Items

Unresolved items are matters which require more information in order to ascertain whether it is an acceptable item, an open item, a deviation or a violation. An unresolved item disclosed during this inspection is discussed in paragraph 7.

13. Open Items

Open items are matters which: have been discussed with the licensee; will be further reviewed by the inspector; and involved some actions on the part of the NRC, licensee, or both. Open items disclosed during the inspection are discussed in paragraph 3.

14. <u>Exit Interview</u>

The inspectors met with licensee representatives (denoted in paragraph 1) during the inspection period and at the conclusion of the inspection period on December 6, 1991. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.