U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-237/90017(DRP); 50-249/90017(DRP)

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

Licensee: Commonwealth Edison Company
P. O. Box 767
Chicago, IL 60690

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

Inspection At: Dresden Site, Morris, IL

Inspection Conducted: June 13 through July 31, 1990

Inspectors: S. G. Du Pont
D. E. Hills
M. S. Peck

Approved By: J. M. Hinds, Chief 8-24-90
Reactor Projects Section 1B Date

Inspection Summary

Inspection during the period of June 13 through July 31, 1990 (Reports Nos. 50-237/90017(DRP); No. 50-249/90017(DRP))
Areas Inspected: Routine unannounced resident inspection of previously identified inspection items, licensee event reports, plant operations, maintenance/surveillances, engineering/technical support and report review.
Results:

- One violation was identified involving three examples of inadequate equipment outage checklists. Two of these examples had similar root causes although an adequate length of time to implement effective corrective actions had occurred between these two examples. Therefore, this item was determined not to fit the criteria for exercise of discretion under 10 CFR 2, Appendix C, Section V.G.1. Although the results of the individual examples were of minimal safety significance, taken in aggregate the inspectors considered them to be indicative of problem in control of this area and thus possible precursors to a more serious event.

- Three unresolved items were identified. The issue involving the drywell manifold sampling system as described in paragraph 6.b was awaiting licensee completion of 10 CFR 50.59 safety evaluations to address specific past practices in the usage of this system. The issue involving components from three systems not appropriately included in the primary

containment local leak rate testing program as described in paragraph 6.c was awaiting further review by NRC regional specialists. The issue involving the facility's compliance with 10 CFR 50.62, anticipated transient without scram rule, as described in paragraph 6.d was awaiting further NRC technical review of design calculations and post-modification testing.

- Two non-cited violations were identified which both involved missed fire watches occurring approximately one month apart as described in paragraphs 4 and 5.a.4. However, root causes were sufficiently dissimilar such that corrective actions from the first event could not reasonably had been expected to prevent the second event. Therefore, these violations were not cited in accordance with 10 CFR 2, Appendix C, Section V.G.1.

- A loss of condenser vacuum event which nearly resulted in a reactor scram is described in paragraph 5.a.6. Although operator actions were sufficient to mitigate the event, it was noteworthy that this event, was precipitated by balance of plant equipment failures. The licensee initiated actions to prevent similar failures in related equipment. The inspectors are continuing to follow the balance of plant equipment maintenance area to ascertain the potential for significant events and the affect upon safety-related equipment.

- Operations continued to be good as indicated by the operator response to events exhibited during the loss of condenser vacuum event. Additional concerns regarding the adequacy of equipment outage checklists was viewed as a weakness in the maintenance program. Until resolution of the unresolved items in the engineering/technical support area, this area is considered indeterminate.

DETAILS

1. Persons Contacted

Commonwealth Edison Company

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

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) Unresolved Item (50-237/89018-03): Licensee to resolve atmospheric containment atmosphere dilution/containment atmosphere monitoring (ACAD/CAM) power supply design deficiency. The ACAD/CAM design is part of the larger hydrogen generation issue currently being handled by the Office of Nuclear Reactor Regulation (NRR) under TAC number 56579/56580. This item is considered closed since the issue is being reviewed and tracked by other means.

(Closed) Unresolved Item (50-237/89005-03): Evaluate effectiveness of engineered safety features (ESF) actuation reduction program due to the number of events involving undervoltage testing. During the December 1988 through February 1990 Unit 2 refueling outage, a total of 12

unplanned ESF actuations occurred. Primarily due to the efforts of the scram/ESF reduction program, this number was reduced to only three during the more recent December 1989 through February 1990 Unit 3 refueling outage. In particular, the licensee investigation of near misses, including half scrams and half isolations, resulted in numerous actions to address this issue. The inspectors have no further concerns in this area.

(Closed) Open Item (50-237/90003-01): Licensee to complete a 10 CFR 50.59 safety evaluation to determine whether an unreviewed safety question exists in regard to the single failure analysis for a turbine pressure regulator failure. Section 11.2.3.2 of the Final Safety Analysis Report (FSAR) indicated that a pressure regulator failure in the wide open direction would result in a 100 psi vessel pressure drop in the first ten seconds resulting in a Main Steam Isolation Valve (MSIV) closure at less than 850 psi reactor pressure. A scram would result from the MSIV closure and depressurization would be stopped due to the isolation. However, with reactor water level initially near the top of the range allowed by the operating procedures, the reactor water level swell due to the single failure could cause a turbine trip on high reactor water level prior to reaching 850 psi reactor pressure. In the condition where reactor power was greater than 40 percent, the reactor would scram due to the turbine trip. The MSIV automatic closure was bypassed when the mode switch was not in the RUN position. If the control room operator immediately placed the mode switch to the shutdown position following the scram in accordance with instructions in the abnormal operating procedures, the MSIV closure would not occur at 850 psi. The FSAR analysis did not account for the possible turbine trip if reactor water level were assumed to be near the top of the allowed operating range.

The licensee completed a safety evaluation dated May 10, 1990, regarding the FSAR discrepancy. This evaluation concluded that the pressure regulator failure at high reactor water level was bounded by existing plant failure analyses. Because of plant specific design, the licensee concluded that vessel overfill was not a credible event and that vessel cooldown would not exceed the limitations addressed in the plant's design basis.

The inspectors no longer have a concern as to whether this failure at high reactor water level constitutes an unreviewed safety question. The licensee planned to incorporate the results of the safety evaluation into the next FSAR update.

No violations or deviations were identified in this area.

3. Licensee Event Reports (LER) Followup (90712 and 92700)

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

(Closed) LER 50-237/90003: Partial Group II Primary Containment Isolation and Standby Gas Treatment Initiation Due to Personnel Error. This event and corresponding corrective actions are discussed in paragraph 5.a.1 of this report.

No violations or deviations were identified in this area except as identified in paragraph 5.a.1 of this report.

4. Plant Operations (71707, 60710 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.

Each week during routine activities or tours, the inspector monitored the licensee's security program to ensure that observed actions were being implemented according to their approved security plan. The inspector noted that persons within the protected area displayed proper photo-identification badges and those individuals requiring escorts were properly escorted. The inspector also verified that checked vital areas were locked and alarmed. Additionally, the inspector also verified that observed 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 also observed new fuel receipt and inspection for the upcoming Unit 2 refueling outage.

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.

In addition, the following operational occurrence was reviewed:

On May 14, 1990, the Unit 3 reactor building low pressure coolant injection (LPCI) rooms/pressure suppression chamber fire alarm light actuated on local fire panel 2223-114 and the device 34-29 (Unit 3 reactor building lower elevation protectowire) was shown in the alarm condition on the control room fire alarm typer. The operators attempted unsuccessfully to reset the alarm and performed an inspection of the

area to ensure that no fire actually existed. When the alarm would not reset the operators assumed equipment failure was preventing the reset and a work request was submitted for repairs. In actuality, the operators did not understand how to reset this particular alarm and the protectowire device could have functioned if it had been correctly reset. The alarm response portion of Dresden Fire Protection Procedure (DFPP) 4185-1, "XL-3 Fire Detection System Operation" was referenced for required actions. However, this procedure had not been updated to indicate the requirements of the Dresden Administrative Technical Requirements (DATR). The DATRs were developed and went into effect in August 1989 to contain the previous fire protection required actions upon their removal from Technical Specifications and other 10 CFR 50 Appendix R requirements.

These requirements were removed from Technical Specifications in accordance with Generic Letters 86-10 and 88-12. The DATRs were in many cases more extensive and stringent than the previous Technical Specification requirements. DFPP 4185-1 still contained the previous Technical Specification requirements which did not address this device. Therefore, no further actions were taken. Approximately eight hours later an equipment operator on the next shift while performing rounds noted the local light in the alarm condition and notified the control room. An inspection of the area was performed and the alarm was correctly reset.

As such, a period of approximately eight hours existed in which the alarm was not reset and would not have been able to provide notice of an actual fire if one occurred. DATR Section 3.1.1.1.a required an hourly fire watch to be established in the LPCI rooms and a once per shift fire watch to be established in the pressure suppression area within one hour of finding this device inoperable. This action was not accomplished during the eight hours.

Further review indicated that DFPP 4185-1 was not among the fire protection procedures that had been updated when the DATRs were instituted. At that time, the fire protection procedures were reviewed to determine the effect of the changed requirements and 24 procedures were revised as a result. However, it was determined that the remaining fire protection procedures could be revised at later dates in accordance with the procedure upgrade program. The majority of these procedures were surveillances with references to the previous applicable Technical Specifications. However, DFPP 4185-1 also contained the alarm response procedures for the XL-3 fire detection system, contrary to what the procedure title would seem to imply as to scope limits of the procedure content. Therefore, this review did not identify that DFPP 4185-1 should also have been changed prior to implementation of the DATRs. In addition, DFPP 4185-1 did not contain specific directions on how to locally reset this particular alarm. Since the operators could not reset the alarm, they incorrectly assumed that the alarm was inoperable. Failure to perform the required fire watches was considered to be a violation of Technical Specification 6.2.A.11 which required adherence to the fire protection program implementing procedures (50-237/90017-01(DRP)). However, the criteria of 10 CFR 2, Appendix C, Section V.G.1 for discretionary enforcement was determined to be applicable and therefore no notice of violation is being issued.

As a result of this event, the licensee instituted a temporary change to DFPP 4185-1 to ensure proper reference to the DATR requirements and appropriate local reset methods. A permanent revision was planned after the Operational Analysis Division completed reviewing alarms on the XL-3 computer for identification. The licensee also reviewed the remaining fire protection procedures to ensure that they did not require immediate changes. Although training had been given to the operators regarding the DATRs when they were first instituted, the licensee determined that further training was advisable in light of deficiencies in operator knowledge exhibited by this event. Therefore, the licensee counseled the involved individuals to ensure their awareness of the requirements, wrote daily orders to operations personnel to address this issue and planned to include further training in the operator requalification program. The licensee was also reviewing possible causes of the spurious linear heat detection alarm and the system engineer was monitoring the performance of the linear heat detection equipment. Due to a subsequent spurious alarm, a work request was written for maintenance to troubleshoot the problem if it should reoccur. A temporary change was made to DFPP 4185-1 to instruct the operators to contact electrical maintenance to perform this activity prior to resetting the alarm.

No violations or deviations were identified in this area except for the non-cited violation described above.

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

a. Maintenance Activities

Station maintenance activities of systems and components listed below were observed or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with Technical Specifications.

The following items were considered during this review:

The Limiting Conditions for Operation (LCOs) were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented. Work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety-related equipment maintenance which may affect system performance.

(1) On February 4, 1990, while performing equipment outage number III-460, a Unit 3 partial group II primary containment isolation unexpectedly occurred initiating a standby gas treatment system (SGTS) automatic start and reactor building

ventilation (RBV) system isolation. The fuse removed during the equipment outage was replaced and the isolation reset. SGTS and the RBV system were returned to normal.

Further review indicated that the outage was being performed in accordance with work request D90128 to allow replacement of a broken terminal point on control room panel 903-4. The fuse was removed in accordance with the outage checklist. The equipment outage checklist for outage number III-460 was inappropriate in that it described removing a fuse which caused the event. The review of the outage by maintenance and operations personnel (including two Senior Reactor Operators) was inadequate in that it failed to identify all effects of removing the fuse. The incorrect equipment outage checklist is considered to be an example of a violation (50-237/90017-02A (DRP)) regarding inappropriate instructions. Safety significance of the resulting action was minimal since the system failed in the safe direction. A review of the drawings and interviews with involved personnel indicated that although the electrical drawings were correct and were reviewed, these individuals did not identify the detailed information on the drawings regarding the purpose of the relays which caused the event. Individuals clearly understood how to read the drawings.

As a result, all SROs received additional training in the continuing training program on the importance of reviewing the detailed information supplied on drawings for individual components. This was accomplished during the 6 week Cycle 4 training which was completed on June 15, 1990. This event was also reviewed with the work analysts as part of a reading package completed on May 30, 1990, to stress the importance of reading all information supplied on drawings with respect to individual components and allowing an adequate amount of time to review the drawings. In addition, the licensee planned on providing additional training to licensed operators stressing the importance of taking adequate time to review the drawings. The licensee also planned to review the SGTS initiation logic to determine possible improvements to circuits with single fuse initiation capability. These last two actions had not been completed prior to the two events involving inadequate equipment outage checklists discussed below. In retrospect, these actions were not adequate or timely enough to prevent two other examples of inadequate equipment outage checklists approximately four months later as described in the following paragraphs. Only one of these other examples, however, was related to the same root cause as this event.

(2) On June 11, 1990, Unit 2 recirculation pump A tripped while performing outage number II-412 for the recirculation pump B motor-generator (MG) oil cooler temperature control valve (TCV) 2-3905-B. This was caused by an MG set trip on high coupling temperature when recirculation pump A MG oil cooler TCV 2-3905-A was mistakenly taken out of service instead. The throttling of the TCV bypass in preparation for removing

ventilation (RBV) system isolation. The fuse removed during the equipment outage was replaced and the isolation reset. SGTS and the RBV system were returned to normal.

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(2) On June 11, 1990, Unit 2 recirculation pump A tripped while performing outage number II-412 for the recirculation pump B motor-generator (MG) oil cooler temperature control valve (TCV) 2-3905-B. This was caused by an MG set trip on high coupling temperature when recirculation pump A MG oil cooler TCV 2-3905-A was mistakenly taken out of service instead.

The throttling of the TCV bypass in preparation for removing TCV 2-3905-B had been accomplished prior to this activity.

Further review indicated that the equipment outage checklist for outage number II-412 was incorrect in that it listed the isolation valve numbers (2-3909-501 and 500) for the recirculation pump B MG set TCV instead of the isolation valve numbers (2-3940-501 and 500) for the intended recirculation pump A MG set TCV. The incorrect equipment outage checklist is considered to be an example of a violation (50-237/90017-02B(DRP)) regarding inappropriate instructions. Safety significance of the resulting action was minimal since the system failed in the safe direction. The applicable critical drawing (M-22) in the control room, indicating the correct configuration found in the plant, had been corrected to reflect drawing change request (DCR) 89-106. The change request was submitted on August 29, 1989, and was still outstanding. The critical drawing in the shift engineer's office, which was not updated to DCR 89-106, was used in preparation of the outage. This drawing incorrectly showed the TCV for the recirculation pump B MG set oil coolers to be TCV 2-3905-A. Dresden Administrative Procedure (DAP) 2-9, "As-Built Critical Drawings," covered only the hard copy up-to-date as-built drawings in the control room. These were provided for operating shift and maintenance personnel for shift decisions, outage management and trouble-shooting. The critical drawings in the shift engineer's office were not "as-built" critical drawings and, as such, should not have been used to prepare or review the outage without reference to the control room drawings. Control room drawings were updated by hand when drawing change requests were received by the station. The revised drawings for the shift engineer's office were issued through engineering and could take up to six months or more after the change request was issued. DAP 3-5, "Out-of-Service and Personnel Protection Cards", prescribed that "only the controlled critical plant piping and instrumentation diagrams, electrical prints card file or Central File shall be utilized for reference to accurately identify the points of isolation." This was misleading since although the drawings in the shift engineers satellite file were controlled, they did not in fact, directly reflect pending drawing change requests. DAP 2-3 "Operation and Control of the Central and Satellite Files," required the appropriate satellite file aperture card to be marked "Revision Pending." This would signify that additional information was needed which could be obtained on the "as-built" control room copy or in Central File. In this case, the outage was prepared from a set of drawings which were not up-to-date and the additional information was not obtained from the Control Room or Central File. Interviews with operating personnel indicated that there

was confusion as to which set of drawings could be used for each type of drawing.

In addition, the equipment attendant (EA) knew that TCV 2-3905-B was to be taken out-of-service but did not question the isolation valves listed on the equipment outage checklist. Upon noticing that the isolation valves listed on the outage matched the "A" TCV instead of the "B" TCV, the EA hung the outage on the "A" TCV isolation valves. The NSO observed the rapidly increasing temperatures on the computer display and the Shift Supervisor and EA returned to the MG sets. There was insufficient time for these individuals to take action since only ten minutes elapsed from the beginning of the increasing temperatures to the pump trip.

As a result of this event, Operations Department memorandum No. 18 was issued on June 26, 1990, which described this event. Specific guidance was included to assist in performing the self check process. It also stressed that if a question or uncertainty exists that the Shift Supervisor should be contacted for assistance. Finally, it gave specific guidance as to which set of drawings to use for outage preparation.

(3) On June 13, 1990, a half group II isolation signal was received on Unit 2 while performing outage number II-421 for work request D89780. This work request involved replacement of non-environmentally qualified terminal blocks with environmentally qualified splices in junction boxes which provided electrical continuity for torus wide range level transmitter 2-1641-5B. The half group II isolation signal was caused by a loss of power to drywell high radiation monitor B on the main control room ACAD/CAM panel when a breaker was opened during the performance of the out-of-service. The equipment attendant was contacted, the breaker was reclosed and the half group II isolation signal was reset.

Further review indicated that the equipment outage checklist for outage number II-421 was inappropriate in that it prescribed opening 480 volt motor control center 29-3 120 volt distribution panel circuit number 6. Review of the outage by maintenance and operations personnel was inadequate in that it failed to identify all effects of opening this breaker. The incorrect equipment outage checklist is considered to be an example of a violation (50-237/90017-02C (DRP)) regarding inappropriate instructions. Safety significance of the resulting actions was minimal since the system failed in the safe direction. A review of the drawings and interviews with involved personnel indicated that although the electrical drawings were correct and reviewed, these individuals did not identify the detailed information on the drawings dealing with this function. (The function of an additional wire leading from this breaker on electrical drawing 12E2679A was not determined.) Individuals clearly understood how to read the drawings. Therefore, the root

cause of this event involving inattention to detail, was the same as that of the February 4, 1990 event described in paragraph 5.a.1.

As a result of this event and its similarity to the previous event, the licensee planned to develop a self-check program consisting of a committee to promote attention to detail and self-checking while performing the task. This committee was to include individuals who were directly involved in these events.

(4) On June 17, 1990, the Unit 3 reactor building LPCI rooms/pressure suppression chamber fire alarm light actuated on local fire panel 2223-114 and device 34-29 (Unit 3 reactor building lower elevation protectowire) was shown in the alarm condition on the control room fire alarm typer. The Center Desk Nuclear Station Operator (NSO) acknowledged the alarm and noted work request sticker 82074 on the typer plexiglass for this alarm. Incorrectly assuming, due to the work request sticker, that the device was known to be inoperable and therefore already handled, the NSO took no other actions. Approximately 17 hours later, another fire protection device alarmed in the trouble condition. While resetting this other device, the NSO noticed that device 34-29 was in the alarm condition. An inspection of the affected area was performed to ensure that an actual fire did not exist. Appropriate fire watches were established in accordance with DATR 3.1.1.1.a and the fire marshal was contacted for instructions on how to reset the local alarm. Although a temporary procedure change to DFPP 4185-1 had been instituted, as a result of the previous event discussed in paragraph 4, to provide these instructions, operating personnel were still unsure of which button to depress in the local fire protection panel. The local panel alarm was reset which allowed the alarm condition to be cleared on the XL-3 computer. At that time, the fire watch was terminated. The crew that discovered this problem and took appropriate action was the same crew that missed the fire watch described in paragraph 4. Therefore, these individuals, in particular, had heightened interest to ensure compliance with fire protection requirements.

As such, a period of approximately 17 hours existed in which the alarm was not reset and thus would not have been able to provide notice of an actual fire if one occurred. DATR 3.1.1.1.a required an hourly fire watch to be established in the LPCI rooms and a once per shift fire watch to be established in the pressure suppression area within one hour of finding this device inoperable. This action was not accomplished during those 17 hours. Failure to perform the required fire watches was considered to be a violation of Technical Specification 6.2.A.11 which required adherence to the fire protection program implementing procedures (50-235/90017-03(DRP)). However, the criteria of 10 CFR 2, Appendix C, Section V.G.1 for discretionary enforcement was determined to be applicable and therefore no notice of violation is being issued. This determination recognized that

the root cause of this event as discussed below and the event discussed in paragraph 4 were sufficiently dissimilar such that corrective actions from the first event could not reasonably had been expected to prevent the second event.

Further review of this event indicated that the root cause was due to inadequate administrative controls regarding work request processing. The work request sticker for this device had been written during the May 14, 1990 event described in paragraph 4. Once the device was determined to be operable and the alarm was reset during the previous event, the work request was cancelled. However, the corresponding work request sticker was never removed. This incorrectly led the NSO to believe that there was an outstanding work request against the device. Dresden Administrative Procedure (DAP) 15-1, "Initiating and Processing a Work Request," placed responsibility for removal of work request stickers with the originator of the work request. However, no dependable method existed to ensure that the originator was informed of this need in a timely manner. In fact, the licensee found that seven of the 18 work request stickers on the typer plexiglass were no longer valid. These were removed. In addition, DAP 15-5, "Supplemental Maintenance Request" did not address cancellation of work requests and removal of stickers at all. Supplemental work requests were written for equipment maintained on a routine or repetitive basis which already had outstanding base work requests. As a result, the licensee planned to revise DAP 15-1 and DAP 15-5 to require that the work group which requested cancellation of a work request remove the corresponding work request sticker.

In addition, a set of daily orders was issued between June 19 and July 2, 1990, to emphasis the importance of DATR compliance and that any new alarm or trouble alarm on the XL-3 fire system was to be treated as a valid alarm (regardless of work request stickers). It also contained a list of the fire detection devices requiring a fire watch if only the one device were inoperable. As described in paragraph 4, a temporary procedure change to DFPP 4185-1 was issued to ensure electrical maintenance performed troubleshooting of this alarm upon recurrence prior to resetting. The licensee also planned to conduct a tailgate session covering this event with the operators to stress that there were eight devices listed in the DATRs which alone would require fire watches if inoperable. The establishment of a log for the XL-3 fire system, similar to the degraded equipment log was planned. This would provide more information than that available on the work request stickers. The log is expected to be established by the end of September 1990. Finally, the licensee was in the process of setting up a committee to assess various problems encountered with the XL-3 fire detection system. This committee was to specifically address concerns of the operators who had been critical of the system.

(5) On June 30, 1990, Unit 3 was shutdown for a maintenance outage. The shutdown was initiated due to high temperatures between 230

and 240 degrees F on the main turbine thrust bearing plate. On June 28, 1990, the licensee reduced power to about 40 percent in an attempt to reduce the thrust bearing plate temperature. The vendor (General Electric) recommended a shutdown on temperatures above 250 degrees F. Since the temperatures could not be reduced with load reduction, the licensee initiated a maintenance outage. Other major activities completed during the outage include replacement of one control rod drive, replacement of a main transformer bushing, and repairs to recirculation pump seal leakoff line flow instrumentation. Approximately 70 items on the unscheduled outage list were also addressed. Upon investigation of the main turbine thrust bearing high temperatures, the licensee found damage to the thrust bearing plate. This was replaced. The licensee did not conclusively determine the root cause of the damage but suspected an improperly placed thermocouple. The unit was restarted on July 4, 1990.

(6) On July 1, 1990, while attempting to reverse circulating water flow on Unit 2 in accordance with Dresden Operating Procedure (DOP) 4400-8 "Circulating Water System Flow Reversal," circulating water flow reversal valves 2-4402A and 2-4403B breakers tripped and the offgas east suction valve 2-5401B failed to open. As a result, condenser vacuum decreased to about 24 inches and a half scram on reactor protection system channel B was received. The scram setpoint was 23 inches. The operator noted the vacuum decrease and immediately reduced recirculation flow to try to maintain condenser vacuum in accordance with Dresden Operating Abnormal (DOA) Procedure 3300-2 "Loss of Condenser Vacuum." In addition, the flow reversal was changed back to the original direction such that condenser vacuum recovered. The inspectors considered the actions of the control room operators as exhibiting high attentiveness and quick response to changing conditions to prevent a reactor scram.

The ASCO solenoid valve body for offgas east suction valve 2-5401B was subsequently changed out after it was determined not to operate. Testing of the molded case circuit breakers for valves 2-4402A and 2-4403B determined that their trip setpoints were too low. The licensee had not conclusively determined the cause for the low trip settings by the end of the inspection period. The trip setting for the breaker for valve 2-4403B could not be adjusted to within acceptable tolerances and so it was replaced. No maintenance history was found on these nonsafety-related breakers. The trip settings on both breakers were reset and returned to service on July 15, 1990. Due to the failure of two of the eight flow reversal valves on Unit 2, the licensee wrote work requests on the remaining flow reversal valves on both units and planned to enter them into the surveillance tracking system for periodic preventative maintenance. Problem analysis data sheets were also initiated to track root cause analysis of the breaker failures.

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:

Control Rod Drive Hydraulic Withdrawal Stall Flow Testing
Standby Liquid Control (SLC) System Pump Test
Quarterly SLC System Pump Test for the Inservice Test Program

One violation as described above and no deviations were identified in this area. In addition, one non-cited violation was identified as described above.

6. Engineering/Technical Support (93702)

a. The inspectors reviewed concerns with control rod drives going to position "02" during scrams. The subject was discussed in length in inspection report 50-237/87007;50-249/87006, and in a letter to Mr. A. Bert Davis from I. M. Johnson (CECo Nuclear Licensing) dated July 14, 1987. The original initiator of the NRC concerns was the August 11, 1986 Dresden Unit 2 scram which resulted in 56 control rods stopping at position "02". As noted in the licensee letter and the inspection report, this phenomenon had occurred at Dresden since 1971 as well as other BWRs, although to a much lesser extent. This phenomenon was also the object of an NRC safety evaluation issued June 15, 1981.

The NRC safety evaluation identified the apparent cause as leakage past worn stop and drive piston seals internal to the drive which allowed scram water to act as a buffer on the drive. This was described as a hydraulic lock occurring because of worn seals and the design of the drive. The design of these drives, associated with BWR classes 3 and 4, had a relative large buffer area and small vent path to slow drives during a scram to prevent internal damage. Later models did not have this apparent problem because of increased vent paths and reduced buffer area size.

General Electric (GE) recommended a revised CRD venting procedure to remove trapped air which could also aid in developing the phenomenon. GE also recommended cleaning of the drives to prevent build up of crud that could also result in drive seal deterioration.

The safety significance of the phenomenon was nonexistent since both the 1987 NRC inspection and 1981 NRC safety evaluation determined that sufficient shutdown margin exists even with all rods inserted only to the "02" position.

The licensee began a series of correction actions in 1987 to reduce or eliminate the "02" phenomenon. These included incorporating the GE revised venting procedure, cleaning drive tubes during refueling outages, overhauling drives demonstrating the "02" phenomenon (indication of seal deterioration) and, if needed, replacing drives with newer models (BWR/6 drives).

As a result, Cycle 11 for both units demonstrated a significant reduction. The licensee had replaced or overhauled all of the "02" drives during Cycle 10 and initiated cleaning of guide tubes. The licensee also replaced all 14 drives in Unit 3 during the last refueling outage. These drives had the following history:

C-09, C-12, H-14 and K-12 occurred once.
F-05, F-10, L-02 and L-05 occurred twice.
G-03 occurred on four occasions.

The following is a table of "02" occurrence on Unit 2 during Cycle 11.

Date	"02" Rods
7/12/89	C-8, D-10 and K-10
3/04/89	C-6, D-10 and K-10
01/05/90	C-6, D-10, E-5, E-8 and F-5
01/16/90	C-6, D-10, E-5, E-8, E-10, F-5 and F-11

As noted in this table, the NRC safety evaluation and NRC inspection report, when "02" phenomenon once occurred, the phenomenon would more than likely repeat within a cycle. These drives were scheduled to be replaced during the next scheduled refueling outage on Unit 2.

The licensee has also reviewed the status of all CRDs in Unit 3 and determined that only 14 of the original 1971 CRDs remain installed in Unit 3. These were also scheduled to be replaced with overhauled BWR/6 drives during the next refueling outage in 1991.

The licensee was continuing with their efforts to resolve the "02" phenomenon. Although a final resolution had not yet been found, these efforts had significantly reduced the occurrence of the phenomenon. Since the licensee was continuing to place efforts on reducing the occurrence of the phenomenon and these efforts did appear to be effective, the inspector has no remaining concerns in this area.

b. On June 28, 1990, the licensee informed the resident inspectors of an alteration to the drywell manifold sample systems on both Units 2 and 3 which affected primary containment integrity. The purpose of the drywell manifold sample system was to provide air samples to

identify the location of reactor coolant pressure boundary leaks inside of the drywell. The drywell manifold sample system (one for each unit) was designed to take a suction from 22 sample points in the drywell with each half inch sample line having its own two manual primary containment isolation valves (both located outside of primary containment) and a filter cartridge. Flow then passed through a common header from which the sample pump took a suction. Return back to the drywell was provided through a connection to the continuous oxygen monitoring system which discharged to the drywell through two automatic containment isolation valves which closed on a Group II isolation signal. Thus, the drywell manifold sampling system had automatic isolation only on its discharge. Piping downstream of the manual isolation valves was nonsafety-related (A portion of this passed through a braided flexible hose as opposed to the rest of the system which was hard piped.). There were also four additional lines which actually took a suction from the continuous oxygen monitoring system, as opposed to directly from primary containment, and therefore had automatic isolation on both the suction and discharge (The continuous oxygen monitoring system had automatic isolation on its suction as well as its discharge.) The drywell manifold sample system had been in place since the plant was built.

Technical Specification surveillance requirement 4.6.D.1 required drywell air sampling to be performed once per day to detect reactor coolant system leakage. This sample was originally obtained through a continuous atmosphere monitoring system which was replaced by another continuous atmosphere monitoring system in the early 1980s. Automatic containment isolation was provided with these systems. As a backup to these systems the drywell manifold sample system as described above was used. As a secondary backup (in case the permanent pump was inoperable) a temporary sample pump was used as far back in time as 1978 and possibly before. The temporary sample pump was readily available since it was already used to obtain samples from the X-area (steam tunnel) at the same sample rack. The second continuous atmosphere monitoring system was abandoned in 1987 due to problems with moisture intrusion, therefore the drywell manifold sampling system and the temporary sample pump became the primary and secondary methods, respectively, of obtaining the Technical Specification required sample. Use of the temporary sample pump involved breaking the closed loop on the drywell manifold sample system below the sample filter on one of the sample lines, attaching a rubber hose with a quick disconnect fitting, running the hose to the temporary sample pump and discharging the pump exhaust to the reactor building. The setup was typically left unattended while a sample was being taken although automatic isolation was not provided. Obtaining a representative sample required running the system in this configuration for at least 50 minutes but in many cases probably went much longer than this (A subsequent procedure specified a minimum of one hour.). This allowed an unattended and unmonitored path from the drywell (primary containment) through the sample line to the reactor building (secondary containment).

This use of the temporary sample pump in that configuration was contrary to Technical Specification 3.7.A.2 which required maintaining of primary containment integrity when the reactor was critical or the reactor water temperature was above 212 degrees F. (The definition of primary containment integrity required that all manual isolation valves on lines connecting to containment which were not required to be open during accident conditions be closed.) Therefore, each time the licensee used the temporary sample pump to sample the drywell, the applicable Technical Specification action statement 3.0.A was unknowingly entered. However, due to the length of time this condition would have existed, this action statement would have been exited prior to any actual shutdown. Calculations performed by the licensee assuming one open half inch sample line at design accident containment pressure, Pa (48 psig), indicated that the leak rate would be 4.73 percent per day. When added to the Technical Specification 3.7.A.2a(3) allowed leakage of 1.6 percent per day, a total leakage of 6.33 percent per day was obtained. This was compared to the design basis leakage of 2.0 percent per day prescribed in the bases of Technical Specifications. A 10 CFR 50.59 safety evaluation was never done on this alteration (use of the temporary sample pump) since the original administrative requirements only applied to lifted leads and jumpers. When the administrative requirements expanded to mechanical equipment, no thought was given to an alteration that had been routinely used for years. As such, in recent years each time this temporary alteration was performed it was done contrary to the licensee's administrative procedures. A procedure covering the use of the temporary sample pump did not exist (until 1989 as described below) and thus the problem was not caught early on through a procedure safety evaluation.

Use of the temporary sample pump was frequent, especially in the last couple of years due to recurring problems with the permanent pumps. (The permanent pumps were estimated by the licensee to have been operable only a few weeks over the last year or two and were troublesome even before that.) Due to a non-documented reviewer comment concerning use of the temporary sample pump without a procedure, Dresden Radiation Protection (DRP) procedure 1350-3, "Sampling the Drywell Manifold System Using the Radeco Air Sampler" was first issued in May 1989. This was a missed chance to detect the problem since a 10 CFR 50.59 safety evaluation should have been performed; however a safety evaluation was not performed. The screening criteria in effect at the time allowed entire categories of procedures (such as DRPs not related to effluent monitoring) to be automatically ruled out for a safety evaluation as long as they were not new or changed "procedures or administrative controls" described in the FSAR or Technical Specifications. In this particular case, since it was a new procedure, the criteria required a safety evaluation to be performed. However, the reviewers mistakenly used the wrong administrative path as if it were a revision to this type of procedure instead of a new procedure. Therefore, a safety evaluation was not performed due to a failure to follow administrative requirements. However, the criteria themselves were still inappropriate since the licensee could have instead

just made a revision to DRP 1350-7, "Operation of the Unit 2(3) Drywell Air Sampling Manifold System" to allow usage of the temporary sample pump. In that case, the licensee's administrative requirements would not have required a safety evaluation to be performed and the same result would have been the same (usage of the temporary sample pump without a safety evaluation). The screening criteria had since been revised such that this was no longer a concern for recent procedures and revisions.

In addition to the Technical Specification required drywell air sample, the drywell manifold sampling system had been used since the plant was built to obtain weekly samples from all the sampling points. This consisted of using the permanent pump to obtain samples from half the sampling points at one time. (Thus, sampling was done with half the sampling lines in simultaneous use twice a week.) This sampling was not done when the permanent sampling pump was inoperable. The design of the drywell manifold sampling system provided for two manual isolation valves both of which were located outside of primary containment. The portion of the drywell manifold system located outboard of the manual containment isolation valves was nonsafety-related. Thus, eleven sample lines with no automatic isolation were routinely and simultaneously opened and left unattended for at least one hour twice a week, providing a path from the drywell, through nonsafety-related piping, back to the drywell.

The licensee took the following actions regarding this issue:

- An assistant technical staff supervisor identified the original problem while reviewing a revision to DRP 1350-3. During this review the individual felt it was confusing as to which valves were being addressed and therefore discussed with the author the possibility of including a diagram in the procedure. During this discussion the individual became aware that the temporary sample pump discharge was into the reactor building. This was not entirely obvious from just reading the procedure.

- Upon discovering the problem, the licensee performed a preliminary analysis to quantify the amount of leakage through a one half inch penetration through primary containment at design accident pressure. After finding that this greatly exceeded allowable limits the licensee informed the NRC.

- The licensee issued a temporary change to the procedure regarding usage of the temporary sample pumps to require an individual in continual attendance and in contact with the control room by radio while the manual isolation valves are open. The licensee subsequently performed a temporary alteration that moved the sample point for the Technical Specification required daily sample to a line that had automatic isolation.

- All incoming Radiation Protection shift personnel were briefed as to the problem to preclude improper usage of the system.

- The licensee initiated a deviation report to track the licensee investigation of the problem. The licensee also initiated a potentially significant event report for corporate management.

- The licensee informed Quad Cities of the problem.

In addition, the licensee has initiated or planned the following actions:

- Due to questions regarding the original system design the licensee was reviewing the design basis and the need for any system design improvements. The licensee had not made a decision whether the system would be repaired and used or whether it was to be abandoned, dismantled and the lines capped.

- The licensee was reviewing methods whereby a temporary return line to the drywell could be established for use with the temporary sample pump. (Although automatic isolation was now provided, the temporary sample pump still exhausted to the reactor building which presented ALARA considerations.)

- Due to the problem with the previous 10 CFR 50.59 safety evaluation screening criteria, the licensee was attempting to determine the population of previous procedures and revisions that would need to be rescreened under the current criteria.

- The licensee was performing a 10 CFR 50.59 safety evaluation addressing two past practices:

  (1) Use of the temporary sample pump exhausting to the reactor building atmosphere with the manual isolation valves left open and unattended.

  (2) Usage of the permanent as-designed system with eleven sampling lines left simultaneously open and unattended.

  These safety evaluations were to include a 10 CFR 100 analysis for offsite doses and a 10 CFR 50, Appendix A, General Design Criterion 19 analysis for control room doses.

This issue is considered an unresolved item (50-237/90017-04(DRP)) pending completion of the licensee's safety evaluations and NRC review of these documents.

c. On July 20, 1990, a dual unit shutdown began from 92 percent and 99 percent rated thermal power on both Units 2 and 3, respectively, in accordance with Technical Specification action statement 3.0.A requiring hot shutdown within 12 hours and cold shutdown within the following 24 hours. A corresponding Unusual Event was declared due to initiation of a shutdown required by Technical Specifications. The shutdown was due to the identification by the licensee of specific components, applied to both units, which had not been local leak rate tested (LLRT) in accordance with 10 CFR 50 Appendix J

requirements. These included a check valve which had not been tested at all and two manual isolation valves whose testing methodology was in question in the reactor building closed cooling water (RBCCW) system inlet to the drywell. In addition, both the inboard and outboard manual isolation valves on a control rod drive line to the recirculation pump seals had not received LLRTs. Finally, a flexitallic gasket on a torus water level transmitter had not received an LLRT. This last item was only a concern for Unit 2 since the one on Unit 3 had been subjected to Integrated Leak Rate Testing (ILRT) pressure within the past 24 months. The problem with RBCCW had been identified earlier at Quad Cities, but was not initially corrected at Dresden. This was because the problem at Quad Cities involved total absence of LLRTs on the RBCCW system and the Dresden problem only involved partial LLRT of this system. Thus, communication only involved whether LLRTs were done on RBCCW and not the total extent of the LLRTs. The absence of these components in these three systems from the LLRT program and the licensee's corrective actions are considered an unresolved item (50-237/90017-05(DRP)) pending further review by regional NRC specialists.

The shutdown was stopped and the Unusual Event terminated with the units at 73 and 80 percent power, respectively, later that same evening upon receipt of a verbal waiver of compliance from the NRC. The waiver of compliance allowed 48 hours to conduct appropriate testing on the control rod drive system and torus water level transmitter line components and until the next refueling outage for each unit on the RBCCW line components. The licensee submitted the formal documentation to support this action on July 23, 1990 and also submitted an emergency Technical Specification amendment request on July 31, 1990, regarding the RBCCW line components. All actions regarding the control rod drive system and torus water level transmitter line components including modifications needed to conduct testing and the testing itself were completed on July 22, 1990. The licensee also issued an operating order describing actions to be taken regarding RBCCW in the event of a LOCA.

d. During 1987, the licensee completed modifications to the Dresden Station Standby Liquid Control System (SLCS) suction piping to facilitate dual pump operation. The modification was performed in pursuit of compliance with the Anticipated Transient Without Scram (ATWS) rule (10 CFR 50.62). At BWRs, the ATWS rule required the SLCS negative reactivity injection rate be increased to the equivalent of 86 gallons per minute of 13 wt/% sodium pentaborate solution. The rule further required the SLCS system to be "designed to perform its function in a reliable manner."

The licensee's SLCS ATWS modification safety evaluation (10 CFR 50.59) stated, in part, "the suction piping has been designed to assure two pump net positive suction head (NPSH) and eliminate concerns of mutually reinforcing pulsations." The inspectors reviewed the SLCS ATWS modification NPSH design calculation. The review indicated the calculation did not include an analytical demonstration of adequate

NPSH but was built upon an assumed plant history of satisfactory single SLCS pump operation. The calculation incorporated the philosophy that minimum available NPSH for two pump operation could be maintained by the addition of a second section of piping, of similar design to the original piping, connecting the SLCS storage tank to the SLCS pump suction header. The calculation indicated that a strict analytical approach to the computation of available NPSH would be overly conservative and placed a reliance on post modification testing to demonstrate satisfactory performance with both pumps in operation.

The inspectors also reviewed the Unit 2 SLCS ATWS post modification test. The test consisted of the monthly single pump operational surveillance test and the single pump reactor vessel injection surveillance. In addition, both pumps were run simultaneously for a 64 second period to verify the dual pump flow rate. During the dual pump test, NPSH was verified by "absence of large noises associated with pump cavitation." The single SLCS pump in-service test program required each SLCS "pump to be run (individually) at least five minutes prior to obtaining data to allow each pump to reach hydraulic stability." In light of the design calculations' reliance on the site testing to ensure SLCS NPSH, the post modification testing was critical to the acceptance of the modification to meet 10 CFR 50.62 criteria. This is considered an unresolved item (50-237/90017-06(DRP)) pending further NRC review to determine adequacy of the design calculations and the post modification testing.

No violations or deviations were identified in this area.

7. Report Review

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

8. Unresolved Items

An unresolved item is a matter 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 Paragraphs 6.b, 6.c and 6.d.

9. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on July 31, 1990 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.