TAB 14

DRESDEN 2 & 3

FIRE PROTECTION PROGRAM DOCUMENTATION PACKAGE

Inspection Report No. 50-237/90017 and 50-249/90017

90017/90017

Revision 8
April 1992

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

AUG 28

AUG 2 4 1990

Docket No. 50-237
Docket No. 50-249

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Opus West III
1400 Opus Place
Downers Grove, IL 60515

Gentlemen:

This refers to the routine safety inspection conducted by S. G. Du Pont, D. E. Hills and M. S. Peck of this office on June 13 through July 31, 1990, of activities at Dresden Nuclear Power Station, Units 2 and 3, authorized by Operating Licenses No. DPR-19 and No. DPR-25 and to the discussion of our findings with Mr. J. Kotowski and others at the conclusion of the inspection.

The enclosed copy of our inspection report identifies areas examined during the inspection. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations, and interviews with personnel.

During this inspection, certain of your activities appeared to be in violation of NRC requirements, as described in the enclosed Notice. These activities were reviewed against the criteria of 10 CFR 2 Appendix C, Section V.G.1 for exercise of discretion, but were not deemed applicable due to the similarity of root causes and adequate length of time for effective corrective action between two of the examples. A written response is required.

An unresolved item described in the enclosed inspection report is awaiting completion of licensee 10 CFR 50.59 safety evaluations regarding specific past practices of drywell manifold sampling system usage. The NRC plans to review these safety evaluations upon their completion prior to resolution of this item.

In accordance with 10 CFR 2.790, of the Commission's Regulations, a copy of this letter and the enclosure(s) will be placed in the NRC Public Document Room.

The responses directed by this letter and the accompanying Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, PL96-511.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

WDShafer
W. D. Shafer, Chief
Reactor Projects Branch 1

Enclosures:
1. Notice of Violation
2. Inspection Report
   No. 50-237/90017(DRP);
   No. 50-249/90017(DRP)

cc w/enclosures:
D. Galle, Vice President - BWR
  Operations
T. Kovach, Nuclear
  Licensing Manager
E. D. Eenigenburg, Station Manager
DCD/DCB (RIDS)
Licensing Fee Management Branch
Resident Inspectors LaSalle,
  Dresden, Quad Cities
Richard Hubbard
J. W. McCaffrey, Chief, Public
  Utilities Division
Robert Newmann, Office of Public
  Counsel, State of Illinois Center

Appendix

NOTICE OF VIOLATION

Commonwealth Edison Company
Dresden Nuclear Station

Docket No. 50-237
Docket No. 50-249

As a result of the inspection conducted on June 13, through July 31, 1990, and in accordance with the General Policy and Procedures for NRC Enforcement Actions, (10 CFR Part 2, Appendix C), (1990) the following violation was identified:

10 CFR 50, Appendix B, Criterion V, as implemented by Commonwealth Edison Company's Quality Assurance Program, requires that activities affecting quality be prescribed by documented instructions, procedures or drawings of a type appropriate to the circumstances.

Contrary to the above, documented instructions for activities affecting quality prescribed in equipment outage checklists were inappropriate to the circumstances in the following cases:

a. Outage number III-460 implemented on February 4, 1990 failed to recognize all consequences of a fuse removal, resulting in an unexpected group II primary containment isolation, standby gas treatment system automatic initiation and reactor building ventilation system isolation.

b. Outage number II-412 implemented on June 11, 1990 prescribed the closure of incorrect valves, resulting in an unexpected recirculation pump trip.

c. Outage number II-421 implemented on June 13, 1990 failed to recognize all consequences of opening a breaker, resulting in an unexpected half group II primary containment isolation signal.

This is a Severity Level IV violation (Supplement I). (237/90017-02(DRP))

Pursuant to the provisions of 10 CFR 2.201, you are required to submit to this office within thirty days of the date of this Notice a written statement or explanation in reply, including for each violation: (1) the corrective steps that have been taken and the results achieved; (2) the corrective steps that will be taken to avoid further violations; and (3) the date when full compliance will be achieved. Consideration may be given to extending your response time for good cause shown.

8/24/90
Dated

W D Shafer
W. D. Shafer, Chief
Reactor Projects Branch 1

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
Reactor Projects Section 1B

8-24-90
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. (Exit 7-31-90)

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. <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.

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

a. <u>Maintenance Activities</u>

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.

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.

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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 (50-23$/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.

Commonwealth Edison
1400 Opus Place
Downers Grove, Illinois 60515

September 24, 1990

Mr. A. Bert Davis
Regional Administrator, Region III
U.S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, IL 60137

Subject: Dresden Station Units 2 and 3
Response to Notice of Violation
Contained in Inspection Report
50-237/90017 and 50-249/90017
NRC Docket Nos. 50-237 and 50-249

Reference: W. Shafer (NRC) letter to C. Reed (CECo), dated August 24, 1990.

Mr. Davis:

The referenced letter transmitted Inspection Report 50-237/90017 and 50-249/90017 for Dresden Station. The Inspection Report contained one (1) Notice of Violation regarding inappropriate equipment outage checklists. Commonwealth Edison Company (CECo) has reviewed the Notice of Violation and agrees that the violation occurred as described. Attachment 'A' to this letter presents CECo's response to the violation, and describes corrective actions which are being taken to prevent similar occurrences.

Please direct any questions or comments on this response to this office.

Respectfully,

T. J. Kovach

T. J. Kovach
Nuclear Licensing Manager

Attachment A: Commonwealth Edison Company Response to Notice of Violation 50-237/90017-02.

cc: B. Siegel - NRR Project Manager
NRR Document Control Desk
S. DuPont - Senior Resident Inspector, Dresden

MR/TK/lmw
ZNLD304

COMMONWEALTH EDISON COMPANY
RESPONSE TO NOTICE OF VIOLATION
50-237/90017-02

VIOLATION (50-237/90017-02)

10 CFR 50, Appendix B, Criterion V, as implemented by Commonwealth Edison Company's Quality Assurance Program, requires that activities affecting quality be prescribed by documented instructions, procedures or drawings of a type appropriate to the circumstances.

Contrary to the above, documented instructions for activities affecting quality prescribed in equipment outage checklists were inappropriate to the circumstances in the following cases:

a. Outage number III-460 implemented on February 4, 1990 failed to recognize all consequences of a fuse removal, resulting in an unexpected Group II primary containment isolation, standby gas treatment system automatic initiation and reactor building ventilation system isolation.

b. Outage number II-412 implemented on June 11, 1990 prescribed the closure of incorrect valves, resulting in an unexpected recirculation pump trip.

c. Outage number II-421 implemented on June 13, 1990 failed to recognize all consequences of opening a breaker, resulting in an unexpected half Group II primary containment isolation signal.

This is a Severity Level IV violation (Supplement I)

RESPONSE

Commonwealth Edison Company agrees with the violation as stated in the Notice of Violation. Although the three cases cited involved inappropriate equipment outage checklists for existing plant conditions, there is a fundamental difference between the recirculation pump trip event that occurred on June 11, 1990 and the other two cases cited. The February 4, 1990 and June 13, 1990 events resulted from inattention to detail during the preparation and review of the equipment outage checklists. In the recirculation pump trip event, the equipment outage checklist was prepared with a drawing which did not indicate a requested drawing change to reflect the in-plant labeling of the temperature control valves. Additionally, the operator hanging the outage failed to question activities that did not seem appropriate for the work in progress and plant conditions.

Dresden Station has been conducting plant walkdowns to upgrade plant labeling. Items which are found not to conform with common labeling convention are corrected and drawing changes submitted. In the recirculation pump trip event, the as-built drawing in the control room had been updated to reflect the correct labeling of the temperature control valves as identified during the plant walkdown; however, that drawing was not used in preparation of the equipment outage checklist.

As a result of these events, Dresden Station has taken actions to emphasize: 1) the need to contact appropriate supervisory personnel if questions or uncertainties arise during any plant activity; 2) the joint responsibility of Operating Department personnel and Maintenance Department work analysts to perform a thorough review to determine the impact of all equipment outages; and 3) the use of the most up-to-date information available when preparing and reviewing equipment outages.

CORRECTIVE ACTION TAKEN AND RESULTS ACHIEVED

Immediate actions to restore the plant to normal conditions were:

1. February 4, 1990 event - The subject fuse was immediately replaced, the isolation reset, and the Standby Gas Treatment and Reactor Building Ventilation Systems were returned to normal.

2. June 11, 1990 event - The subject valves were reopened, but not in time to prevent the trip of the recirculation pump. Control room operators correctly carried out the requirements of DOA 202-1, "Recirculation Pump Trip - One or Both Pumps." The plant was returned to two loop operation.

3. June 13, 1990 event - The subject breaker was racked back in, and the half Group II isolation signal was reset.

Immediately following each event, an investigation was conducted to determine the root cause of each event, and to formulate and implement corrective actions. The events in June 1990 prompted additional corrective actions regarding the development, review and implementation of equipment outages.

CORRECTIVE ACTIONS TAKEN TO AVOID FURTHER NON-COMPLIANCES

Following the June 1990 events, the following corrective actions were taken.

1. Operations Department Memorandum #18 was issued to reaffirm with all Operations Department shift personnel the need to use the most up-to-date available critical drawings when preparing and verifying equipment outages, and to contact supervisory personnel when activities do not seem appropriate for current plant conditions/evolutions prior to performing the activity.

2. A letter discussing the causes of the three events, the similarities of the events, and the corrective actions taken to prevent reoccurrence has been sent to all Operating Department shift personnel and Maintenance Department work analysts. A further detailed review of these events with shift personnel and work analysts will be conducted by December 14, 1990.

3. In order to provide readily available, accurate information for personnel involved with equipment outage preparation and verification, an additional set of as-built critical drawings will be placed in the Operations Department Scheduler's office. Dresden Administrative Procedure 2-9, "As-Built Critical Drawings," is being revised to control these drawings. This set of drawings will be copies of those used in the control room and will reflect the "as-built" condition of the plant, including any outstanding drawing change requests. These actions will be completed by September 28, 1990.

4. Dresden Station has formed a committee to develop a "Self-Check" policy for personnel to follow while performing work in the plant. The policy includes verifying all equipment, labeling and procedures prior to starting a job, anticipating expected plant responses, stopping if any response is not received, and observing that all anticipated responses occur. A draft of these guidelines has been developed and will be implemented by October 1, 1990.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on June 13, 1990 when the half Group II isolation was reset.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

November 28, 1990

Docket Nos. 50-237 and 50-249
License Nos. DPR-19 and DPR-25
EA 90-168

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Opus West III 1400 Opus Place
Downers Grove, Illinois 60515

Gentlemen:

SUBJECT: NOTICE OF VIOLATION AND PROPOSED IMPOSITION OF CIVIL PENALTY - $37,500 (NRC INSPECTION REPORT NOs. 50-237/90017(DRP); 50-249/90017(DRP); 50-237/90022(DRP); 50-249/90022(DRP))

This refers to the special safety inspections conducted during the period of June 13 through July 31, 1990 and during the period of June 28 through September 20, 1990 at the Dresden Nuclear Power Station. During these inspections a violation of NRC requirements was identified by your staff, and on October 12, 1990, an enforcement conference was held in the Region III office between Mr. D. Galle, and other members of your staff, and Dr. C. J. Paperiello, and other members of the NRC staff. Copies of the inspection reports were mailed to you on August 24, 1990 and October 4, 1990, and a copy of the enforcement conference report was sent on October 24, 1990.

On June 28, 1990, with Units 2 and 3 operating at 99% and 48% power respectively, during the review of a proposed revision to DRP 1350-3 "Sampling the Drywell Manifold System Using the RaDeco Air Sampler", one of your employees, an Assistant Technical Staff Supervisor, discovered that obtaining the required daily air sample using this procedure both challenged the integrity of primary containment and potentially violated Technical Specification (TS) 3.7.A.a.(3) primary containment leakage requirements. Specifically, this procedure addressed obtaining the required air sample by breaking the closed loop on the drywell manifold air sample system and using a temporary sample pump in lieu of the normal air sample pump. In this configuration and under this procedure, the temporary sample pump would run unattended for approximately one hour daily and exhaust into the secondary containment with no automatic isolation capability. In addition, this represented a condition that could, by your own calculations, increase primary containment leakage beyond the allowed leakage of 1.6% per day (TS 3.7.A.a.(3)) by an additional 4.73% per day for a total leakage of 6.33% per day. It is my understanding that this method of air sampling using the temporary sampling pump has been used as a secondary backup method to obtain the required air sample since approximately 1978. We also understand that the required air samples were originally obtained through the use of a continuous air monitor (CAM) with the drywell manifold air sample system as the primary backup.

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

The root cause of this event was your failure to recognize that use of the temporary air pump constituted a design change that required the performance of a proper engineering review and the establishment of proper procedural controls prior to its implementation.

Consequently, this resulted in a significant failure to meet the requirements of 10 CFR 50.59. Specifically, each time that the temporary sample pump was used, you failed to perform the evaluation necessary to determine whether the activity constituted a change in the TSs and/or an unreviewed safety question. In this case, the use of the temporary sample pump effectively constituted a change in the TSs' allowable leakage rate and represented an unreviewed safety question in that the additional leakage rate (4.73%) nullified the margin of safety as defined in the basis to the TSs. This violation is significant in that (based on your calculations using design basis methodologies) both limits for the thyroid dose for control room habitability and for the 30 day thyroid dose at the low population zone would have been exceeded. Although you performed additional analyses that indicated that acceptable offsite and control room doses would have been obtained, those analyses, that were based on assumptions that were less conservative than those used in the plant licensing basis, still would have required changes to the Final Safety Analysis Report (FSAR), TSs, and TS bases. However, the determination of the acceptability of such analyses is an NRC function, and requires NRC approval prior to implementation of the change. Therefore, in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," (Enforcement Policy) 10 CFR Part 2, Appendix C (1990), this violation has been categorized as a Severity Level III violation.

The NRC recognizes that immediate corrective action was taken when the violation was identified. In addition, the NRC was informed of your subsequent corrective actions during the October 12, 1990 enforcement conference. During this discussion, you informed us that as part of your corrective action for this event, that you had identified that a 10 CFR 50.59 review had not been completed prior to disconnecting the CAM in the early 1980's, despite the fact that it was an FSAR requirement. I understand that you have reinstalled the CAM on Unit 3 and will reinstall it on Unit 2 prior to its startup from its current refueling outage.

To emphasize the need for recognizing design changes and for performing the necessary evaluations in accordance with the provisions of 10 CFR 50.59, I have been authorized, after consultation with the Director, Office of Enforcement, and the Deputy Executive Director for Nuclear Reactor Regulation, Regional Operations and Research to issue the enclosed Notice of Violation and Proposed Imposition of Civil Penalty (Notice) in the amount of $37,500 for the Severity Level III violation. The base value of a civil penalty for a Severity Level III violation is $50,000. The escalation and mitigation factors in the Enforcement Policy were considered.

I recognize that your employee went beyond his normal duties in identifying the violation and wish to encourage you to continue such aggressive reviews. The fact that this employee took the time to look into and question the process instead of routinely approving a procedure revision is to be commended.

However, this violation might have been identified earlier if an aggressive review had taken place on several prior occasions. First, in 1986, the unreviewed safety question might have been identified if your revisions to the temporary alteration program had extended to cover use of the temporary sample pump, either at that time or when use of the pump was reinstated in 1987. Second, in August 1988, when your temporary alteration program was extended to cover use of mechanical equipment, the unreviewed safety question might have been identified if you had recognized the use of the temporary pump as a temporary alteration. Finally, in May 1989, when the procedure governing use of the temporary sample pump was created (in response to a third party reviewer's recommendation made in 1988), the unreviewed safety question might have been identified if you had properly performed a safety evaluation as required by your own procedure. Therefore, only partial mitigation (25%) was deemed warranted for the identification factor. Fifty percent mitigation was applied due to the extensiveness of your corrective actions, once you recognized that an unreviewed safety question existed. With respect to your past performance, the NRC notes that you received two previous Severity Level IV violations involving changes to the facility without prior evaluation and authorization in the past two years. I recognize that the corrective action for those violations would not necessarily have prevented the subject violation. In addition, the NRC has noted a significant improvement in the performance of your technical staff organization as evidenced by your latest SALP rating in the area of E&TS, as well as the more aggressive scrutiny that your employees are giving to routine reviews. Therefore, 50% mitigation was applied for past performance. However, I am especially concerned in this case due to the number of years that the temporary sample pump was regularly used on a daily basis and the potential for a significant offsite release should a design basis LOCA have occurred during those times. In addition, the NRC is concerned that, for a substantial number of years, it appears that you failed to properly understand and evaluate the intent and requirements of the containment air sample system such that the proper corrective actions for the system requirements could have been implemented. Therefore, the base civil penalty was escalated by 100% based on the duration factor. The other factors of the Policy were considered and no further adjustment to the base civil penalty was considered appropriate. Therefore, based on the above, a civil penalty in the final amount of $37,500 is proposed.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, PL 96-511.

Sincerely,

Carl J Paperiello for

A. Bert Davis
Regional Administrator

Enclosures:
1. Notice of Violation and Proposed Imposition of Civil Penalty
2. Inspection Report Nos. 50-237/90022(DRP); 50-249/90022(DRP)

cc w/enclosures:
D. Galle, Vice President - BWR Operations
T. Kovach, Nuclear Licensing Manager
E. D. Eenigenburg, Station Manager
DCD/DCB (RIDS)
OC/LFDCB
Resident Inspectors LaSalle, Dresden, Quad Cities
Richard Hubbard
J. W. McCaffrey, Chief, Public Utilities Division
Robert Newmann, Office of Public Counsel, State of Illinois Center

NOTICE OF VIOLATION
AND
PROPOSED IMPOSITION OF CIVIL PENALTY

Commonwealth Edison
Dresden Nuclear Power Station

Docket Nos. 50-237 and 50-249
License Nos. DPR-19 and DPR-25
EA 90-168

During NRC inspections conducted on June 13 through July 31, 1990 and June 28 through September 20, 1990, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1990), the Nuclear Regulatory Commission proposes to impose a civil penalty pursuant to Section 234 of the Atomic Energy Act of 1954, as amended (Act), 42 U.S.C. 2282, and 10 CFR 2.205. The particular violation and associated civil penalty is set forth below:

10 CFR 50.59(a) states, in part, that a holder of a license may make changes in the facility as described in the safety analysis report without prior Commission approval unless the proposed change involves a change in the technical specifications incorporated in the license or an unreviewed safety question. It also states, in part, that a proposed change shall be deemed to involve an unreviewed safety question if the margin of safety as defined in the basis for any technical specification is reduced.

Section 14.2.6.4.1 of the Final Safety Analysis Report (FSAR) states, in part, that the Air Sample System be configured such that the "air sample will be drawn through the tubing, out through a drywell penetration, auto-isolation valves, and then to a continuous air monitor."

Section 14.2.4.2.C of the Updated Safety Analysis Report (USAR), which discusses offsite dose releases following a Loss of Coolant Accident (LOCA), states, in part, that the primary containment leaks 0.5 percent of the contained free volume per 24 hours at 25 psig. Section 14.2.4.3 of the USAR, which discusses post-LOCA control room dose rates, states, in part, that activity releases are based on a containment leakage rate of 1.6 percent per day.

Technical Specification 3.7.A.2.a(3) states that the maximum allowable leakage rate at a pressure of Pa, La, is equal to 1.6 percent by weight of the containment air per 24 hours at 48 psig. The bases for the surveillance requirements for Section 3.7.A.2 explain that the maximum allowable test leak rate (1.6% was derived from the maximum allowable accident leak rate of about 2 percent/day, when corrected for the effects of containment environment under accident and test conditions. The bases additionally state that the accident leak rate could be allowed to increase to about 3.2 percent/day before the guideline thyroid doses value given in 10 CFR 100 would be exceeded, so that establishing the test limit of 1.6 percent/day provides an adequate margin of safety to assure the health and safety of the general public.

Contrary to the above, the licensee, without prior Commission approval, on a sporadic basis since 1978 and on an almost daily basis from 1987 up to discovery in June 1990, made changes to the facility as described above in the safety analysis report (automatic isolation was not provided during containment air sampling) that involved a change to the Technical Specifications (TSs) and constituted an unreviewed safety question. Specifically, use of a temporary sample pump to obtain the required daily drywell air sample would have involved a change to the TSs in that the maximum allowable leakage rate (1.6 percent/day) would have been increased by 4.73 percent/day for a total leakage of approximately 6.33 percent/day. Use of the temporary sample pump constituted an unreviewed safety question in that this amount exceeded the leakage specified in the bases for the above TS section, such that the margin of safety defined therein was eliminated.

This is a Severity Level III violation (Supplement I)
Civil Penalty - $37,500.

Pursuant to the provisions of 10 CFR 2.201, Commonwealth Edison Company (Licensee) is hereby required to submit a written statement of explanation to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, within 30 days of the date of this Notice of Violation and Proposed Imposition of Civil Penalty (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each alleged violation: (1) admission or denial of the alleged violation, (2) the reasons for the violation if admitted, and if denied, the reasons why, (3) the corrective steps that have been taken and the results achieved, (4) the corrective steps that will be taken to avoid further violations, and (5) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order may be issued to show cause why the license should not be modified, suspended, or revoked or why such other actions as may be proper should not be taken. Consideration may be given to extending the response time for good cause shown. Under the authority of Section 182 of the Act, 42 U.S.C. 2232, this response shall be submitted under oath or affirmation.

Within the same time as provided for the response required under 10 CFR 2.201, the Licensee may pay the civil penalty by letter addressed to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, with a check, draft, money order, or electronic transfer payable to the Treasurer of the United States in the amount of the civil penalty proposed above, or the cumulative amount of the civil penalties if more than one civil penalty is proposed, or may protest imposition of the civil penalty in whole or in part, by a written answer addressed to the Director, Office of Enforcement, U. S. Nuclear Regulatory Commission. Should the Licensee fail to answer within the time specified, an order imposing the civil penalty will be issued. Should the Licensee elect to file an answer in accordance with 10 CFR 2.205 protesting the civil penalty, in whole or in part, such answer should be clearly marked as an "Answer to a Notice of Violation" and may: (1) deny the violation listed in this Notice in whole or in part, (2) demonstrate extenuating circumstances, (3) show error in this Notice, or (4) show other reasons why the penalty should not be imposed. In addition to protesting the civil penalty in whole or in part, such answer may request remission or mitigation of the penalty.

In requesting mitigation of the proposed penalty, the factors addressed in Section V.B of 10 CFR Part 2, Appendix C (1990), should be addressed. Any written answer in accordance with 10 CFR 2.205 should be set forth separately from the statement or explanation in reply pursuant to 10 CFR 2.201, but may incorporate parts of the 10 CFR 2.201 reply by specific reference (e.g., citing page and paragraph numbers) to avoid repetition. The attention of the Licensee is directed to the other provisions of 10 CFR 2.205, regarding the procedure for imposing a civil penalty.

Upon failure to pay any civil penalty due which subsequently has been determined in accordance with the applicable provisions of 10 CFR 2.205, this matter may be referred to the Attorney General, and the penalty, unless compromised, remitted, or mitigated, may be collected by civil action pursuant to Section 234c of the Act, 42 U.S.C. 2282c.

The response noted above (Reply to Notice of Violation, letter with payment of civil and Answer to a Notice of Violation) should be addressed to: Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region III, 799 Roosevelt Road, Glen Ellyn, Illinois 60137, and a copy to the NRC Resident Inspector at the Dresden Nuclear Power Station.

FOR THE NUCLEAR REGULATORY COMMISSION

Carl J Paperiello for

A. Bert Davis
Regional Administrator

Dated at Glen Ellyn, Illinois
this 28th day of November 1990

Tab 15

DRESDEN 2 & 3

FIRE PROTECTION PROGRAM DOCUMENTATION PACKAGE

Inspection Report No. 50-237/90023 and 50-249/90023

90023/90025

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

Revision 8
April 1992

DEC 0 7 1990

Docket No. 50-237
Docket No. 50-249

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Opus West III
1400 Opus Place
Downers Grove, IL 60515

Gentlemen:

This refers to the routine safety inspection conducted by D. E. Hills, M. S. Peck, J. D. Monninger, D. E. Jones and J. A. Holmes of this office on September 29 through November 16, 1990 of activities at Dresden Nuclear Power Station, Units 2 and 3 authorized by Operating License Nos. DPR-19 and DPR-25 and to the discussion of our findings with Mr. E. Eenigenburg and others at the conclusion of the inspection.

The enclosed copy of our inspection report identifies areas examined during the inspection. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations, and interviews with personnel.

During this inspection, certain of your activities appeared to be in violation of NRC requirements, as specified in the enclosed Notice. A written response is required.

One licensee identified non-cited violation is identified within this report. This issue involved an inadequate out-of-service checklist which resulted in an inadvertent automatic start of the swing diesel generator. We have chosen not to issue a notice of violation because this violation met the criteria delineated in 10 CFR Part 2.

In accordance with 10 CFR 2.790, of the Commission's Regulations, a copy of this letter and the enclosure(s) will be placed in the NRC Public Document Room.

DEC 0 7 1990

The responses directed by this letter and the accompanying Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, PL 96-511.

We will gladly discuss any questions you have concerning this inspection.

W D Shafer
W. D. Shafer, Chief
Reactor Projects Branch 1

Enclosure: Inspection Reports
No. 50-237/90023(DRP);
No. 50-249/90023(DRP)

cc w/enclosure:
D. Galle, Vice President - BWR Operations
T. Kovach, Nuclear Licensing Manager
E. D. Eenigenburg, Station Manager
DCD/DCB (RIDS)
OC/LFDCB
Resident Inspectors LaSalle, Dresden, Quad Cities
Richard Hubbard
J. W. McCaffrey, Chief, Public Utilities Division
Robert Newmann, Office of Public Counsel, State of Illinois Center

APPENDIX

NOTICE OF VIOLATION

As a result of the inspection conducted on September 24 through November 16, 1990, and in accordance with the "General Policy and Procedures for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1990), the following violations were identified:

1. 10 CFR 50, Appendix B, Criterion II, as implemented by Commonwealth Edison's "Quality Assurance Program" requires indoctrination and training of personnel performing activities affecting quality as necessary to assure that suitable proficiency is achieved and maintained.

   Contrary to the above, indoctrination and training of personnel performing activities affecting quality was inadequate in assuring proficiency was achieved and maintained as to administrative requirements as indicated in the following examples:

   a. Lack of operations personnel knowledge of Dresden Administrative Procedure (DAP) 7-5, "Operating Logs and Records," Revision 8, and Dresden Operating Abnormal (DOA) Procedure 902-5 G-2, Revision 3, requirements for maintaining the Control Rod Drive Accumulator High Water / Low Pressure Alarm Log (AHWLPAL) resulted in the AHWLPALs for both units not being maintained between April 1990 and August 3, 1990. As such the licensee's program to identify repeat failures of accumulator alarms was not effective during that time period. (50-237/90023-01a (DRP))

   b. Lack of technical staff personnel knowledge regarding recognizing and processing conditions adverse to quality resulted in a failure to properly identify a procedural nonadherence involving maintenance of the AWHLPAL when discovered in May 1990. Because of this, corrective actions to prevent recurrence were not taken at that time. (50-237/90023-01b (DRP))

   This is a Severity Level IV violation (Supplement 1).

2. 10 CFR 50, Appendix B, Criterion V, as implemented by Commonwealth Edison Company's Quality Assurance Program, requires that activities affecting quality be accomplished in accordance with documented instructions, procedures or drawings.

   Contrary to the above, activities affecting quality were not accomplished in accordance with documented instructions, procedures, or drawings in the following examples:

   a. Dresden Operating Procedure (DOP) 1900-3, "Reactor Cavity-Dryer Separator Storage Pit Fill and Operation of the Fuel Pool Cooling and Cleanup System During Refueling," Revision 8, requires constant communication between the refueling floor and the control room while filling the reactor vessel. Constant communication between the refueling floor and the control room was not maintained while filling the Unit 2 reactor vessel on October 14, 1990, resulting in the overfilling of the vessel into the ventilation ducts and contamination of various areas of the third and fourth floors of the reactor building. (50-237/90023-02a (DRP))

b. Specific practices required by DAP 3-5, "Out of Service and Personnel Protection Cards, Revision 22, were not followed as to preparation, review, approval, documentation and independent verification in the removal and return to service of the Unit 2 diesel fuel oil day tank drain valve on October 29, 1990. This resulted in the inadvertent draining of the day tank when the drain valve was placed in the incorrect position. (50-237/90023-02b (DRP))

c. DAP 7-14, "Control and Criteria For Locked Equipment and Valves," Revision 2, requires manual valves in the flowpath of systems required for plant shutdown during post-accident situations or which provide a controlled path to the environs, including primary and secondary containment isolation valves to be locked. Prior to November 1990, manual valves including the Units 2, 3 and 2/3 diesel generator service water three-way valves and the Units 2 and 3 drywell manifold sampling system containment isolation valves were not locked or designated to be locked. (50-237/90023-02c (DRP))

d. DAP 15-6, "Preparation and Control of Work Requests," Revision 0, requires work to be performed per repair manual(s), travelers/procedures, or work instructions provided in the work package. On October 15, 1990, work prescribed for disassembly of the Outboard Containment Isolation Feedwater Check Valve 220-62B was performed instead on Outboard Containment Isolation Feedwater Check Valve 220-62A. (50-237/90023-02d (DRP))

e. DAP 15-6, "Preparation and Control of Work Requests," Revision 0, requirements were violated on August 8, 1990, when work prescribed for calibration of Unit 3 Torus to Reactor Building Vacuum Breaker A Pressure Transmitter DPT-1622A was performed instead on Pressure Transmitter DPT-1622B. This resulted in advertant opening of the Unit 3 Reactor Building Vacuum Breaker B. (50-237/90023-02e (DRP))

This is a Severity Level IV violation (Supplement 1).

3. 10 CFR 50, Appendix B, Criterion XVI, as implemented by Commonwealth Edison's "Quality Assurance Program," requires that conditions adverse to quality be promptly identified and corrected and, in the case of significant conditions, the measures assure the cause is determined and corrective action taken to prevent repetition.

Contrary to the above, following the fuel bundle mispositioning events of January 10 and 12, 1989, corrective actions were insufficient to prevent repetition in that similar events occurred on October 1, 1990 and October 2, 1990. (50-237/90023-08 (DRP))

This is a Severity Level IV violation (Supplement 1).

Pursuant to the provisions of 10 CFR 2.201, you are required to submit to this office within thirty days of the date of this Notice a written statement or explanation in reply, including for each violation: (1) corrective action taken and the results achieved; (2) corrective action to be taken to avoid further violations; and (3) the date when full compliance will be achieved. Consideration may be given to extending your response time for good cause shown.

12/07/90
Date

W D Shafer
W. D. Shafer, Chief
Reactor Projects Branch 1

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/90023(DRP); 50-249/90023(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: September 29 through November 16, 1990

Inspectors: D. E. Hills

M. S. Peck

J. D. Monninger

D. E. Jones

J. A. Holmes

Approved By: B. L. Burgess, Chief
Projects Section 1B

Date

Inspection Summary

Inspection during the period of September 29 through November 16, 1990 (Reports No. 50-237/90023(DRP); 50-249/90023(DRP)).
Areas Inspected: Routine unannounced resident inspection of previously identified inspection items, licensee event reports followup, plant operations, maintenance and surveillances, engineering and technical support, safety assessment/quality verification and report review.

Results:

Three violations were identified with numerous examples. One involved the failure to follow procedures and instructions and included five examples. These examples permeated different disciplines and involved failing to utilize or ignoring procedures and instructions or inattention to detail in implementing these requirements. Specifics are described in paragraphs 4.a, 4.c, 4.e, 5.a.2 and 5.b.1. The second violation involved inadequate corrective actions in regard to fuel bundle mispositioning events with two examples. Specifics are described in paragraph 7.a. The third violation involved inadequate training to assure adequate knowledge of plant administrative requirements with two examples. Specifics are described in paragraph 2.

One violation was identified which concerned an inadequate out of service checklist. However, a Notice of Violation was not issued in accordance with the discretionary enforcement policy described in 10 CFR 2, Appendix C, Section V.A. Specifics are described in paragraph 4.b.

Five unresolved items were identified. An unresolved item involving a possibly inoperable source range monitor while moving fuel in that core quadrant is pending further NRC review of the event (paragraph 4.f). An unresolved item involving the licensee's policy of not declaring equipment inoperable and not entering corresponding limiting conditions for operation when equipment was purposely rendered inoperable for surveillance testing is pending further clarification of requirements (paragraph 4.g). An unresolved item involving licensee maintenance practices on Appendix R fire protection emergency lighting is pending completion of a licensee investigation report (paragraph 5.b.3). An unresolved item involving the licensee's discovery that the filter media in the Unit 3 Reactor Building Ventilation Air Particulate Sampler had been misalligned is pending further review by NRC regional specialists (paragraph 5.b.2). Finally, an unresolved item involving the licensee's usage of Quality Control Inspection Feedback Sheets is pending further NRC review of that area (paragraph 7.c).

Plant Operations

A number of events occurred during the current Unit 2 refueling outage indicative of personnel performance problems such as communications and inattention to detail. Although they were spread across several disciplines, noteworthy events involving the plant operations functional area included two fuel bundle mispositioning events, a reactor cavity overflow event, inadvertent draining of a diesel generator fuel oil day tank and an inadvertent diesel generator automatic start. Although the safety significance in all cases was minimal, the number of events represent an adverse trend.

Maintenance/Surveillance

In addition to the events above, other adverse events occurred in the Maintenance/Surveillance functional area. Noteworthy among these were an inadvertent automatic start of a core spray pump, disassembly of the wrong feedwater containment isolation check valve and calibration adjustments to the wrong torus to reactor building vacuum breaker pressure transmitter. These were indicative of personnel performance problems such as communications and attention to detail.

Engineering/Technical Support

Review of a modification and associated field work did not identify any problems. One of the violations described in the report involved the lack of a formal training program to assure appropriate technical staff personnel were trained on applicable administrative requirements.

Safety Assessment/Quality Verification

Licensee management recognized the adverse trend in the number of events indicative of personnel performance problems. Management involvement was highly evident in the review of these events and the determination of corrective actions. In addition, generic corrective actions were implemented as described in paragraph 7.b. However, one violation concerned inadequate corrective actions in regard to fuel bundle mispositioning events. Another involved failure of technical staff personnel to recognize procedural nonadherence as a condition adverse to quality such that corrective actions to address the root cause was not taken. This was indicative of a personnel training deficiency. It must be noted however that the inspectors regard licensee corrective actions to normally be thorough and comprehensive.

DETAILS

1. Persons Contacted

Commonwealth Edision 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
M. Korchynsky, Operating Engineer
B. Zank, Operating Engineer
J. Williams, Operating Engineer
R. Stobert, Operating Engineer
M. Strait, Technical Staff Supervisor
L. Johnson, Q.C. Supervisor
J. Mayer, Station Security Administrator
D. Morey, Chemistry Services Supervisor
D. Saccomando, Health Physics Services Supervisor
*K. Kociuba, Quality Assurance Superintendent
*D. Wheeler, Engineering and Construction
*B. Viehl, Engineering and Construction
*G. Kusnik, Quality Control
*K. Yates, Onsite Nuclear Safety Group Administrator

The inspectors also talked with and interviewed several other licensee employees, including members of the technical and engineering staffs, reactor and auxiliary operators, shift engineers and foremen, electrical, mechanical and instrument personnel, and contract security personnel.

*Denotes those attending one or more exit interviews conducted informally at various times throughout the inspection period.

2. Previously Identified Inspection Items (92701 and 92702)

(Closed) Violation 50-237/89019-01(DRP): Failure to place isolated emergency core cooling system (ECCS) level switch in tripped condition resulting in Technical Specification (TS) violation.

In addition to interim actions taken by the licensee, the inspector verified that the licensee had developed and placed in the control room a Technical Specification Instrumentation Operability Manual. This provided guidance on the preferred method of placing Technical Specification instrumentation in the tripped condition and assistance in locating the proper controlled documents to be used in this regard. Operations Policy Statement No. 23 was issued on July 31, 1990, to provide instructions regarding usage of this manual. The inspector has no other concerns in this area.

(Closed) Unresolved Item 50-237/90019-01(DRP): Review shift operations failure to maintain the Control Rod Drive (CRD) Accumulator High Water/Low Pressure Alarm Log (AHWLPAL) for the period between April 1990 and August 30, 1990. The AHWLPAL was used to document CRD accumulators that become degraded due to either a low pressure or high water level condition and facilitated as a tracking tool to determine if a particular accumulator exhibited a recurring problem. During the period in question, no record of CRD accumulators degraded by a low pressure or high water level condition could be located by the licensee. The average frequency of accumulator alarms was approximately once per shift per unit.

Dresden Administrative Procedure (DAP) 7-5, "Operating Logs and Records", Revision 8, provided detailed instructions for the maintenance of records and logs which were administratively required to be maintained for the life of the plant. Step B.8 of DAP 7-5 required a AHWLPAL to be maintained for each unit as an ongoing record of CRD accumulator alarms. Additionally, the Accumulator High Water/Low Pressure annunciator response procedure, Dresden Operating Abnormal (DOA) 902-5 G-2, Revision 3, directed the Nuclear Station Operator (NSO) to review past entries in the AHWLPAL following a new alarm, and to initiate a maintenance work request if a particular accumulator was exhibiting a recurring problem. DOA 902-5 G-2 also required the NSO to document the new accumulator alarms in the AHWLPAL.

The requirements for the AHWLPAL were transferred into DAP 7-5 on December 8, 1989, from the Unit Operator's Daily Surveillance Log, Appendix A. The failure of shift personnel to complete the AHWLPAL during the period between April 1990 and August 30, 1990, was related, in part, to inadequate training of operations personnel at the time of the transfer such that some individuals were not aware of the administrative requirement. Review of the Unit 3 AHWLPAL (the Unit 2 AHWLPAL had been lost) indicated at least seven NSOs had followed the CRD logging requirements until April 1990. Interviews indicated that inadequate training also contributed to these NSOs ceasing performance of the logging requirements in that they were not aware that this was a continuing official requirement. However, the source document, DAP 7-5 was identified on each AHWLPAL page. Additionally, copies of the source document, sheathed in a clear plastic document protector and defining the requirements for the log, were found at the beginning of the log book. This is of concern because plant operations personnel, without proper direction from management, stopped the performance of documentation activities for records. Inadequate training of appropriate personnel as to administrative requirements concerning the AHWLPAL was considered to be an example of a violation (50-237/90023-01a (DRP)) of 10 CFR 50, Appendix B, Criterion II.

The inspectors found through interviews, that the technical staff CRD system engineer knew through independent review of the programmatic failure to maintain the AHWLPAL, per the administrative requirements of DAP 7-5 and DOA 902-5 G-2, since approximately May 1990. The system engineer was not cognizant of and had not been trained on the requirements of DAP 9-12, "Procedural Adherence Deficiencies," Revision 0, to document failures to meet the procedural intent or to perform steps and activities contained within a procedure. Through additional interviews, the inspectors found that the problem of unfamiliarity and lack of training for the documentation of procedural adherence deficiencies was not limited to this single individual. This was significant in that the use of DAP 9-12 facilitates the identification, management review of, and resolution tracking including corrective actions of conditions adverse to quality associated with procedural inadherence. Although the system engineer knew a change in the method of documenting CRD accumulator alarms was planned and, as such, was not concerned, this did not correct the immediate problem nor did it address why the NSOs were not following an administrative requirement. Although other plant reporting and corrective action mechanisms existed that could have also provided these functions, these other plant deviation reporting programs were also not used. Inadequate training of appropriate personnel in regard to recognizing and processing this procedural inadherence as a condition adverse to quality such that adequate corrective action could be taken is considered an example of a violation (50-237/90023-01b (DRP)) of 10 CFR 50, Appendix B, Criterion II.

Both of these examples of violations would appear to be indicative of an overall problem involving personnel knowledge of plant administrative requirements and the significance of these requirements. Although some training on administrative requirements is given to personnel, there is an absence of an overall program to control and ensure appropriate personnel are trained on administrative requirements that they need to know to perform their duties.

(Closed) Unresolved Item 50-237/90022-03(DRP); 50-249/90022-03(DRP): Review licensee's incorporation of safety evaluation reports into the Updated Final Safety Analysis Report (UFSAR). In an Enforcement Conference conducted in the NRC Region III Office on October 12, 1990, the licensee described the schedule for reconstitution of the UFSAR and measures to ensure adequate 10 CFR 50.59 evaluations in the interim. The Enforcement Conference is documented in Inspection Report 50-237/90025; 50-249/90024. The inspector has no further concerns in this area.

(Closed) Open Item 50-249/86012-48: Observation 2.5.4 from Safety System Outage Modification Inspection (SSOMI). Concern regarding use of silicone grease on valve gaskets, seals and seats versus leak tightness. This item was reviewed in Inspection Report 50-237/89026; 50-249/89025, in response to the licensee's discovery of grease on the internals of the Unit 3 reactor building to torus vacuum breaker check valves. It was concluded that the grease discovered on the check valves was applied prior to the corrective actions to prevent greasing of valve seats to pass local leak rate tests. These corrective actions were described in that report. The inspector also reviewed the work request package for feedwater outboard check valve 220-62B which contained specific prohibitions against use of lubricant on valve seats including a quality control hold point to verify this. The inspector has no other concerns in this area.

(Closed) Allegation AMS No. RIII-90-A-0102 (Part B): Falsification of Training Records. An allegation was made to the NRC concerning falsification of training records by "whiting-out" and backdating to show that training was received prior to performing work. According to the alleger, training was given on grinding and flapping of welds for generic use on October 10, 1990. The craft workers were told to backdate the training records to September 20, 1990, to show that training was given prior to starting the task. The alleger and two other workers refused to backdate the training record and entered October 10, 1990. These three entries were "whited-out" and changed to September 20, 1990.

The inspector interviewed employees of Fluor Contractors International, Inc., (FCII), and reviewed FCII Site Procedure SP-II-02, Revision 0, "Orientation, Indoctrination and Training." FCII Procedure SP-II-02 referenced the FCII training matrix for required training. Grinding and flapping are craft skills that would be performed either by a pipefitter or boilermaker. The required training for these crafts was FCII orientation and DAPs 1-4. Only the pipefitter and boilermaker foremen were required, by the FCII training matrix, to receive training in job specific procedures.

In order to reduce job errors, the foremen performed a walkdown of the job and reviewed the task to be performed with the craft prior to starting the work. To give the craft a sense of personal responsibility, this informal training was documented using the Training Report Form found in FCII training procedure SP-II-02. This work review and training documentation was not procedurally required.

The inspector reviewed work areas found in the "Outage Package Status Report." Three areas were identified that would include grinding and flapping as part of the work. These were Inservice Inspection (ISI), Erosion/Corrosion, and the Reactor Vessel Level Instrumentation System (RVLIS) Modification. The inspector reviewed the training report forms associated with the following work packages:

ISI Work Package Nos. D93346-1 through 21
Erosion Corrosion Work Package Nos. D93350-1 through 7
RVLIS Work Package Nos. D94094-1 through 10

The allegation was partially substantiated, in that there were training report entries where the date had been altered by writing over the original date. In one instance, the training report was dated September 21, 1990, and the first three entries were originally dated October 10 or 20, 1990 and then written over to reflect September 20, 1990. No white-out was used to alter the entry.

However, the training was not procedurally required and the training record was not a document required by the quality program. The contractor has indicated that a new form may be used in the future to document the work review. No further action is considered necessary in this area.

<u>Duplicate Items</u>

The following Unit 3 items are being closed because they are duplicates of corresponding Unit 2 items. These issues are still open and being tracked through the Unit 2 tracking numbers.

50-249/90022-01
50-249/90022-02

Two examples of a violation and no deviations were identified in this area.

3. Licensee Event Reports Followup (90712 and 92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event report was 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 237/90010: Core Spray Pump 2B Automatic Start. This event including licensee corrective actions is discussed in paragraph 5.a.1.

No violations or deviations were identified in this area.

4. Plant Operations (60705, 60710, 71707, 71710, 71714 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. The inspectors reviewed new procedures and changes to procedures that were implemented during the inspection period. The review consisted of a verification for accuracy, and correctness. 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.

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.

In addition, a general plant walkthrough inspection was performed by NRC, Region III, Division of Reactor Projects, Branch 2, on October 16, 1990.

Comments from that inspection including those concerning radiation practices were provided to the licensee for resolution.

Unit 2 was shutdown for refueling on September 23, 1990. The inspectors reviewed the technical adequacy of approved procedures and establishment of administrative controls for refueling activities through Dresden Fuel Procedure (DFP) 800-1, "Master Refueling Procedure," and other associated refueling and operating surveillance procedures. The inspector also verified implementation of these administrative controls prior to and during fuel movements by review of appropriate completed checklists, logs and surveillances, direct observation, personnel interviews, and verification that Technical Specification requirements for refueling were met. Observation of new fuel receipt and licensee inspection was documented in inspection report 50-237/90017; 50-249/90017. Activities prior to fuel movement were also observed including reactor shutdown and various aspects of removal of the shielding blocks, drywell head, reactor vessel head and dryer/separator. The inspectors verified that key personnel possessed an adequate understanding of their individual responsibilities and administrative requirements through direct observation and personnel interviews. Adequate staffing for refueling activities and adequate plant cleanliness conditions were also verified by the inspectors. Appropriate radiation protection controls were verified to have been implemented in conjunction with these activities. The inspectors also verified that steps were being taken for the fuel handling foremen to activate their senior reactor operator licenses in accordance with 10 CFR 55.53(f)(2).

Specific incidents involving fuel handling activities are discussed in paragraph 7.a.

The inspectors performed a detailed walkdown of the accessible portions of the Unit 2 high pressure coolant injection (HPCI) system and the Unit 3 core spray (CS) system. At the time of the walkdown, the Unit 2 HPCI system was out of service for maintenance and modifications. Several minor deficiencies regarding the HPCI and CS systems were noted by the inspectors which were quickly resolved by the plant staff to the inspectors' satisfaction.

The inspector reviewed the licensee's program and procedures relating to preventative measures taken for extreme cold weather. In response to IE Bulletin 79-24, the licensee stated that safety-related process, instrument and sampling lines had not experienced freezing and that the above ground ECCS lines entering the Dresden Unit 2/3 contaminated condensate storage tanks were well insulated, heat traced and contained in an insulated permanent enclosure. In addition, all other safety-related instrument and sampling lines were indoors and not exposed to sub-freezing temperatures. The inspector verified the material condition of the insulation on the ECCS lines, the presence of heat tracing and the adequacy of the insulated enclosure. The inspector verified the completion of Dresden Operating Surveillance (DOS) 010-9, Revision 2, which outlined equipment manipulations and inspections to be performed in preparation for seasonal weather changes. This surveillance specified the seasonal requirements for energizing tank heaters, heat tracing and space heaters, and for inspecting steam heating coils and pipe insulation for signs of degradation.

Various operational occurrences were also reviewed as follows:

a. On October 14, 1990, while Unit 2 was defueled, approximately 1,300 gallons of contaminated condensate water were spilled onto the third and fourth floors of the reactor building. The spill was the result of overflow of water through the reactor cavity ventilation duct openings. The reactor cavity was being flooded to support reactor vessel internal inspection but level should not have been raised past the bottom of the duct openings. Cavity fill was accomplished with condensate flow from the condenser hotwell with makeup from the condensate storage tank. The fuel handlers were initially monitoring cavity level from the refuel floor but later left, and informed the NSO of their departure. The change in level from that last reported by the fuel handlers and that later reported by an Equipment Attendant (EA) was noted to differ from the change reflected on the control room indication. In addition, the NSO realized that control room indicated level had risen to where it had been maintained a week earlier. As such, the Shift Engineer and Shift Supervisor verified level to be below the ducts from the refuel floor. However, they did not approach close enough for positive verification since this would have necessitated changing into anti-contamination clothing. Therefore, they verified that the EA had gotten closer on his earlier check. Although the EA was later dispatched to again check level, the overflow occurred prior to the EA reaching the refuel floor.

   Further review indicated that a precaution in Dresden Operating Procedure (DOP) 1900-3, "Reactor Cavity-Dryer Separator Storage Pit Fill and Operation of the Fuel Pool Cooling and Cleanup System During Refueling," Revision 8, required constant communication between the refueling floor and the control room while filling the reactor vessel to prevent overflow into the ventilation ducting. However, neither of the two operating crews involved in the vessel filling actually utilized the procedure nor was the precaution followed. Failure to maintain constant communication between the refueling floor and control room while filling the reactor vessel in accordance with DOP 1900-3, is considered to be an example of a violation (50-237/90023-02a (DRP)) of 10 CFR 50, Appendix B, Criterion V. The operating crews were counselled in the significance of the event, the need for attention to detail and procedural adherence. All Operating Engineers were instructed to reference procedures when possible in Daily Orders. (The Daily Orders which prescribed filling the reactor vessel had not done this.) In addition, a misleading operator aid being used in the control room was revised as to ventilation opening level. The Shift Engineers were also instructed to ensure procedures were out and adhered to for all complex, unique or infrequent evolutions. Further corrective actions to address general concerns about events during the refueling outage are discussed in paragraph 7.b.

Additional longer term event specific corrective actions were being developed by the licensee.

b. On October 27, 1990, the Swing Unit 2/3 Diesel Generator (DG) received an unplanned automatic start and tied to Unit 2 ESF Bus 23-1. At the time of the event, Unit 2 was in a refueling outage and Unit 3 was in power operation. The event occurred while removing Busses 23 and 23-1 from service in accordance with out-of-service (OOS) request II-1549 to facilitate breaker and cubicle preventative maintenance work. The intent was to remove these buses from service while still allowing the swing DG to supply Unit 3 if required. Further review indicated that actions were accomplished with OOS II-1549; however, the OOS was incorrect. The individual who wrote the OOS, who held an inactive Senior Reactor Operator (SRO) license, correctly summarized by reviewing the applicable electrical schematic drawing that four knife switches had to be opened to accomplish the desired action. As this individual believed the drawing to be unclear as to the precise designation and location of the knife switches such as to make identification of the actual corresponding switches in the plant difficult, Dresden Operating Surveillance (DOS) 6600-6, "Bus Undervoltage and Emergency Core Cooling System Test for the Unit 2/3 DG" was referred to for clarification. Unfortunately, one of the switches in the procedure was not the same as to what that individual thought was the corresponding switch on the drawing. While the correct switch designated on the drawing was actually located on Bus 23-1, the one in the procedure was located on a small panel about 3 feet behind Bus 23-1. It was incorrect to use the procedure in this respect since it was designed for a different function. (In fact, in this test, the diesel generator was supposed to start.) DOP 6500-11, "De-energizing 4KV Bus 23-1 for Maintenance," referenced the proper knife switches but was also not utilized in preparing the OOS. The OOS was reviewed in accordance with the licensee's administrative program by a Shift Foreman (SF) with an active SRO license. The first individual had attached a copy of the relevant page from the procedure to the OOS which keyed the SF into using it in his review. Therefore, the OOS was incorrect due to referencing of inappropriate documents for clarification of the electrical schematics during its preparation. As such, the OOS was not appropriate to the circumstances in violation (50-237/90023-03 (DRP)) of 10 CFR 50, Appendix B, Criterion V.

The inspectors reviewed a recent previous violation involving incorrect OOS checklists with three examples and determined the root causes to be sufficiently dissimilar. Therefore, this event could not have reasonably been expected to have been prevented by the licensee's corrective action for the previous violation. The licensee initiated improvements to the undervoltage knife switches for all the Unit 2 and Unit 3 4 KV busses which had the potential for an unplanned DG start. The licensee also planned to develop specific procedures for de-energization of all Unit 2 and Unit 3 4 kv bus combinations which have the potential for an unplanned DG start. Additional plans were initiated for issuance of a policy statement clarifying types of situations in which Operations should request assistance from other departments during OOS preparation and verification. As this was considered to be an isolated occurrence and appropriate corrective actions were initiated, a Notice of Violation is not being issued in accordance with 10 CFR 2, Appendix C, Section V.A. Safety significance was also minimal since all loads had already been removed from Bus 23-1. Opening of the incorrect switch defeated some interlocks for ECCS equipment that were already OOS for the outage.

c. On October 20, 1990, a fuel oil spill occurred in the Unit 2 diesel generator room. This was discovered by two members of the Technical Staff about the same time Unit 2 DG fuel oil day tank level alarm was received in the control room. Diesel fuel oil day tank drain valve 2-5212-500 was found partially open and was immediately closed. A fire watch was posted until the spill was cleaned up. Approximately 500 gallons of fuel was spilled to the oil separator tank with some drain funnel overflow onto the Unit 2 DG room floor. Safety significance was minimal since the DG was OOS for maintenance at the time. Further review indicated that this valve and diesel fuel oil transfer pump suction valve 2-5201B-500 were checked to be shut by a non-licensed Operations Supervisor on October 8, 1990, in preparation for cleaning the main fuel oil storage tank. "Do Not Operate" tags supplied by the cleaning vendor were placed on the valves. However, no Dresden OOS was written for this activity. On October 20, 1990, the Operations Supervisor opened both these valves to restore them to what he believed to be their previous positions and, thereby creating the drain path. The Operations Supervisor was aware of OOS administrative requirements but failed to follow them to expedite the process. These administrative requirements contained in DAP 3-5, "Out-of-Service and Personnel Protection Cards," prescribe specific practices for removing and returning equipment to and from service including preparation, review, approval, documentation and independent verification methodologies. Failing to follow DAP 3-5 in regards to OOS requirements is considered to be an example of a violation (50-237/90023-02b (DRP)) of 10 CFR 50, Appendix B, Criterion V. The Operations Supervisor was counseled as to the importance of interacting with Operations Department shift personnel and the necessity of following OOS administrative requirements. In addition, the day tank valves on all emergency DGs were locked shut.

d. During observation of the repair of the Unit 2 diesel generator service water (DG SW) Dezurik three-way valves (2-3905-525 and 2-3931-525) per Work Requests D90498 and D90499, the inspectors developed concerns regarding previous operations of the DG. In February, 1990, both valve stems were found sheered through at the bonnet separating the valve operators from the plugs. The valves are used for flow reversal through the DG cooling water heat exchangers (HX). If either one of the two valve positions were changed without the other, then cooling water flow would completely bypass the DG cooling HX.

When the Shift Supervisor (SS) was notified of the degraded DG SW valves on February 9, 1990 a determination of the Unit 2 DG operability was appropriate. Although it was not clear through interviews with associated individuals what the licensee considered in the operability determination, through review of additional documentation the inspectors agree that the DG was operable.

However, as the determination of operability was not easily discernible, the inspectors were concerned that the justification for the operability determination was not documented. DAP 7-9, "Malfunction of Safety Related Equipment" discussed logging in the Shift Supervisor's Log significant information surrounding the circumstances so that a reasonable judgement can be made of the cause of the problem and its significance. However, DAP 7-9 was ambiguous as to the threshold for safety-related equipment problems for which this would apply. Review of the Shift Supervisor's log and interviews with licensee personnel indicated that documentation of the justification for operability calls was not a current practice at Dresden. As a result of a Corporate Nuclear Operations Directive issued prior to the inspector's concern, the licensee already had plans to address this as part of an equipment operability program. Specifically, the licensee planned to have a procedure that would prescribe documentation by December 31, 1990. The inspector has no further concerns in this area.

A review of past performances of Dresden Operating Surveillance (DOS) 6600-2, "Reversal of Emergency Diesel Generator Cooling Water Flow" subsequent to the February 9, 1990 discovery of the degraded valves revealed a complete performance of the Unit 2 DG SW flow reversal on February 25, 1990. Due to the degraded condition, turning of the valve handwheel during the surveillance would not have resulted in actual valve position change although the plug position indicator would have shown a change. As a result, the failure to achieve actual flow reversal went unrecognized and the licensee's commitment to IE Bulletin 81-03, "Flow Blockage of Cooling Water to Safety System Components by Corbicula and Mytilus" was not fulfilled. However, the safety significance of not performing the flow reversal in this case was minimal since the DG surveillance indicated adequate HX differential pressure and DG cooling. Since the intent was to perform the flow reversal, the licensee's surveillance program accounted for the commitment, and the safety significance in this case was minimal, this failure to achieve the actual flow reversal is not being considered a deviation from the NRC commitment. Of more concern to the NRC is the fact that these valves were known to be degraded such that the handwheel could not be used to change valve position and yet the licensee did not ensure this knowledge was applied to the subsequent surveillance performance. These valves were not repaired until over eight months after discovery. In addition, if only one of the two DG SW valves had been degraded, the action by the operator on February 25, 1990, would have resulted in the isolation of cooling water to the DG. However, this condition would have been identified by step 9 of DOS 6600-2, which required the operator to stand by at the DG to confirm proper SW cooling flow during the monthly DG operating surveillance test run conducted on February 25, 1990. In this case, the licensee's administrative programs were ineffective in assuring that the status and ramifications of degraded equipment was made known to appropriate personnel and reflected in decisions regarding subsequent activities.

e. DAP 7-14, "Control and Criteria For Locked Equipment and Valves," described the criteria for the selection of valves which were to be locked in position. Included in DAP 7-14 were manual valves which;

- Maintain or could compromise the operability of an Emergency Core Cooling System (ECCS). Step 2.a (2)

- Are in the flowpath of systems which are required for safe plant shutdown during post-accident situations. Step 2.a (3)

The inspectors observed that the DG SW Dezurik three-way valves on each of the three DGs were maintained in an unlocked condition. These valves were not listed in DOP 040-M3, "Locked Valve List: Accessible During Operations," Revision 13. The mispositioning of either one of the two DG SW valves would result in the isolation of the DG from cooling water flow. The DGs provided the emergency electrical power source for the ECCS systems. Based on the Technical Specification definition of operability, the status of the DG could compromise the functionality of the ECCS. Additionally, the DG, as defined in the UFSAR, was required for safe shutdown during design bases events, which included the simultaneous loss of offsite power. Although other manual valves were correctly locked in the DG system, an exception had been made in this case due to the design of these particular valves which make them more difficult to operate. However, the intent of locking valves was to provide a positive barrier to personnel to signify the importance of that particular valve's position. In this case, that barrier was not provided and the licensee's administrative procedure did not allow for that exception.

The inspectors noted that the manual containment isolation valves on the drywell manifold sample systems were also unlocked on both units. These valves were also not included in DOP 040-M3. The issue of locked manual containment isolation valves was addressed in the systematic evaluation program (SEP). As indicated in a Safety Evaluation Report dated September 24, 1982, the NRC position was that manual containment isolation valves should be administratively controlled and locked in a closed position such that the valves were not inadvertently opened during periods when containment integrity was required. This staff position on manual containment isolation valves at Dresden has been consistent with NRC 10 CFR 50, Appendix A, General Design Criteria, 55, 56, and 57. As part of the SEP process, CECo committed, per correspondence on November 18, 1982, from T. J. Rausch to P. O'Connor, to changing the appropriate procedures to implement administrative controls ensuring manual containment isolation valves would be locked closed. The licensee's administrative procedures were consistent with this commitment.

Failure to maintain the DG SW three-way valves and the drywell manifold sample system manual containment isolation valves in a locked condition in accordance with DAP 7-14 is considered an example of a violation (50-237/90023-02c (DRP)) of 10 CFR 50, Appendix B, Criterion V.

f. During fuel loading on November 12, 1990, fuel loading was suspended when abnormal indications were recognized on Source Range Monitor (SRM) 23. While investigating the cause of these indications from under the reactor vessel, instrument maintenance technicians noted that SRM 22 had dropped from its fully inserted position. Subsequently, SRM 22 failed a response test such that it appeared SRM 22 may not have been operable and responding for a short period while loading fuel in its corresponding core quadrant. This is considered an unresolved item (50-237/90023-04 (DRP)) pending further review of the extent and cause of this problem.

g. The inspectors noted that the licensee's policy was not to declare Technical Specification (TS) equipment inoperable and officially enter associated TS limiting conditions for operation when the equipment was purposely rendered inoperable for the purpose of TS surveillance testing. Examples included the standby liquid control system test in which the injection path was manually isolated, the diesel generator surveillance in which manual loading of the diesel generator rendered the load shedding feature inoperable, HPCI and isolation condenser isolation instrument surveillance in which an installed jumper prevented automatic isolation and a torus to reactor building vacuum breaker instrumentation surveillance in which the differential pressure transmitter was valved out-of-service. In addition, the inspectors noted that upon a control rod accumulator high water/low pressure alarm which indicated possible inoperability of the accumulator, the practice was to allow up to an entire shift prior to investigating the alarm. This permits a long delay during which the accumulator may be inoperable and action not taken to restore the accumulator to operability. These practices in regard to Technical Specification operability are considered an unresolved item (50-237/90023-05 (DRP)) pending further clarification of requirements.

Three examples of a violation, one example of a non-cited violation, and no deviations were identified in this area.

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 (LCO) 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.

The inspectors witnessed or reviewed portions of the following activities:

Rebuild of the 2A2 Diesel Generator Air Start Relief Valve
Welding of the "C" Recirculation System Riser Overlays
Unit 2 Diesel Generator Service Water Three-way Valve Repair
Control Rod Drive Replacement
Recirculation Pump 2A Suction Valve Repair
Unit 2 Diesel Generator Air Start Regulator Replacement

Various occurrences were also reviewed as follows:

(1.) On October 3, 1990, while the reactor was being defueled, core spray (CS) pump 2B automatically started. At the time, all low pressure coolant injection (LPCI) pumps were out of service and both CS pumps were operable. During refuel conditions, Technical Specifications only require operability of two CS pumps, two LPCI pumps, or a combination of one LPCI and one CS pump. Only one diesel generator was operable for Unit 2 in accordance with Technical Specifications for refuel conditions. This was the swing 2/3 diesel generator which supplied emergency power to CS pump 2A.

Electrical maintenance personnel were performing a preventive work package on the Unit 2 diesel generator output breaker. This involved removal of the breaker from the cubicle, cleaning of the cubicle and replacement of a contact switch inside the cubicle. This switch, in series with the CS pump actuation circuitry, was to provide information to the circuitry on whether the diesel generator output breaker was open. The CS circuitry upstream of the switch was de-energized since an actual initiation signal was not present. Changing out the switch did not render the pump inoperable since it was still capable of automatic start through the load sequence portion of the circuitry. This would have just resulted in a ten second start delay. If an actuation signal occurred, this portion of the circuitry picked up in parallel to the immediate start circuitry regardless of whether an undervoltage condition existed.

The most likely cause of the automatic start was that while changing out the switch a lead may have inadvertently been grounded allowing enough voltage from the downstream circuitry to pick up the pump start relay. After ensuring that an initiation signal was not present or needed, the operators took the pump control switch to pull-to-lock. No other portion of the system actuated except for the pump minimum flow valve. The CS pump was considered inoperable at that point and the appropriate action statement entered.

Electrical technicians were aware that although the breaker was out-of-service and removed from the cubicle, the circuitry involving the switch was not out-of-service. Therefore, the instrument technicians were aware that adverse actions could occur with this activity and, therefore, took precautions in accordance with the work package including utilization of a rubber mat. The work package was discussed with Operations personnel prior to receiving permission to begin the work. This included review of associated drawings that indicated the existence of core spray interlocks. However, it was not entirely clear from the work package and the reviewed drawings as to what the interlocks accomplished. As such, the licensee believed that if Operations personnel were aware of the nature of these interlocks they may have halted the work activity for a few days until the CS pump was scheduled to be removed from service. As such, the licensee's corrective action was to require listing in the work package of possible specific interactions for any equipment that may have interlocks that affect other systems or contacts that may energize or de-energize equipment or related circuits. In this way, Operations reviewers would have more information on which to base decisions as to whether to let work begin. It must be noted however, that this type of decision is dependent on the individual and the circumstances such that permission to proceed may be given anyway. Therefore, this corrective action may not be sufficient to preclude repetition. However, in this case, the inspectors believed the root cause to be difficult to address since reasonable precautions were taken in changing out the switch. In addition, arriving at this root cause was by process of elimination of any other causes but was still not conclusive beyond any doubt. Further corrective action to address general concerns about events during the refueling outage is discussed in paragraph 7.b.

(2.) On October 15, 1990, Unit 2 outboard containment isolation feedwater check valve 220-62A was mistakenly disassembled instead of the corresponding train B valve. Due to leakage problems, both the A and B valves were to be worked on sometime during the refueling outage. The B train had been correctly taken out-of-service in accordance with OOS II-1279 on October 6, 1990. The Mechanical Maintenance Foreman (MMF) responsible for the job, walked down the OOS on the correct train on October 11, 1990. However, the MMF later mistakenly directed work to be performed on the A valve. Work package D81758 clearly designated the B valve. In addition, sufficient identification tagging existed on the A train such that the problem would have been apparent if the tags had been checked. Quality control hold points existed in the work package but were on later instructions involving re-assembly of the valve. In addition, Technical Staff engineers responsible for local leak rate testing examined the valve after the valve cover was removed. These individuals also failed to recognize that this was not the B valve. The Technical Staff system engineer was aware of the work but did not personally view the valve since other Technical Staff personnel were performing that function. As such, the lack of attention to detail on the part of the MMF, coupled with the unquestioning reliance of other personnel that the MMF was correct, caused the wrong valve to be disassembled and not discovered until October 9, 1990. DAP 15-6, "Preparation and Control of Work Requests," Revision 0, required work to be performed per repair manual(s), traveler/procedure, or work instructions provided in the work package. Failure to disassemble the correct valve in accordance with the work package is considered to be an example of a violation (50-237/90023-02d (DRP)) of 10 CFR 50, Appendix B, Criterion V.

On that date radiation protection personnel noted that doses to workers on that job were much less than expected since the B valve was known to be more highly contaminated than the A valve. A check as a result of this information identified the error. It must be noted that the disassembly actually occurred prior to the generic attention to detail corrective actions discussed in paragraph 7.b. It was fortunate that safety significance in this case was minimal. The A line had been used approximately two days earlier for filling the Unit 2 reactor vessel cavity. Therefore, if the valve had been in a disassembled state just two days earlier, the X-area (steam tunnel) would have been flooded. In addition, if the inboard containment isolation feedwater check valve hadn't held, the reactor vessel cavity could have partially drained back through this line. The licensee was still developing event specific corrective actions at the end of the inspection period.

(3.) On October 19, 1990, the inspectors identified six Appendix "R" emergency lights (required for safe shutdown in the event of a disabling fire) with the electrolyte level below the add line. The inspector observed electrolyte level varying from just below the add line to one inch below the add line.

The Emergency Lighting Monthly Inspection, Dresden Electrical Surveillance (DES) 4153-02, stated that "Electrolyte level shall be at the full line". However, contrary to the established procedure, the licensee indicated that a practice had been followed such that the emergency lights need only be filled when the electrolyte level was at or below the add line. The licensee further indicated that also contrary to the established procedure, the determination to add distilled water was at the discretion of the maintenance personnel. Conversations with the emergency light vendor and review of the vendor technical manual indicated that allowing the electrolyte level to fall below the add line could cause damage to the battery.

After the inspector identified the low electrolyte level in the emergency lighting units, the licensee initiated immediate corrective actions which consisted of:

(1.) Inspected and provided maintenance on Unit 3 emergency lights requiring servicing (for example adding distilled water to a battery with low electrolyte level.) Unit 2 was defueled at the time.

(2.) Review of the emergency lighting maintenance procedure.

(3.) Conduct of an investigation.

On November 14, 1990, the licensee indicated that an investigation report was being developed and would include an event summary, root cause(s) and corrective action(s) which would also be implemented for Unit 2. In addition, the licensee would document the emergency lights in the as-found condition on emergency lighting drawings. The licensee also indicated the investigation report and the marked up drawings for Unit 3 will be tentatively completed by December 14, 1990. This is considered an unresolved item (50-237/90023-06 (DRP)) pending review of the licensee's submittal.

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:

Unit 3 Rod Swapping
Emergency Light Eight Hour Discharge Test
Radwaste River Discharge SPING Calibration/Setpoint Adjustment

Unit 2 250 VDC Battery Discharge Test
Source Range Monitor Checklist

The following occurrences were also reviewed:

(1.) On August 8, 1990, while calibrating the Unit 3 Torus to Reactor Building Vacuum Breaker A Pressure Transmitter, DPT-1622A, the instrument technician inadvertently adjusted DPT-1622B causing Vacuum Breaker B to open. DPT-1622A calibration was being checked per Dresden Instrument Surveillance (DIS) 1600-20, "Torus to Reactor Building Differential Pressure Transmitter 1622A and B Calibration and Maintenance Inspection" in accordance with Work Request D94439. This and other prescribed testing was to collect data for a non-detectable failure evaluation of Rosemont (Model 1153) transmitters. During the check DPT-1622A was valved out-of-service in accordance with the procedure and was, therefore, inoperable. When the as-found readings were discovered to be outside the tolerance range described in the procedure, the instrument technician was to perform a re-calibration to correct the problem. The two transmitters were located approximately eight inches apart and access to the calibration adjustments were on the underside of the transmitters. Each of the transmitters were labelled with a small label under the transmitter. To adjust the calibration setting, the instrument technician had to turn backwards to where he was previously standing performing the calibration check in order to look up at the transmitter from below. Therefore, the transmitter that had previously been on the technician's left for the calibration check was then on the right for the adjustment. As such, the technician mistakenly adjusted the wrong transmitter. DAP 15-6, "Preparation and Control of Work Requests", Revision 0, required work to be performed per repair manual(s), traveler/procedure, or work instructions provided in the work package. Failing to follow the work request by adjusting the wrong transmitter is considered to be an example of a violation (50-237/90023-02e (DRP)) of 10 CFR 50, Appendix B, Criterion V. However, safety significance is considered to be minimal in this case since adjustments were made in a direction that were conservative to Technical Specifications and, therefore, Vacuum Breaker B was never inoperable as to its relief function during the event. In addition, although the vacuum breaker was open for a brief time and therefore unable to perform a containment isolation function, its corresponding check valve remained closed. The vacuum breaker was immediately restored. The licensee counseled the instrument technician on the need for total job awareness especially when working in congested areas such as this. This event was also tailgated to instrument department personnel. The licensee also enhanced the labeling of both the Unit 2 and 3 transmitters and planned to rotate the transmitters such that the adjustment screws could be viewed from the top.

(2.) On November 14, 1990, the licensee discovered that the filter media in the Unit 3 Reactor Building Ventilation Air Particulate Sampler had been misaligned in the filter holder. This allowed a portion of the sample flow to bypass the filter. This is considered to be an unresolved item (50-237/90023-07 (DRP)) pending further review for the cause and significance of this event.

Two examples of a violation and no deviations were identified in this area.

6. Engineering and Technical Support (37828)

The inspectors reviewed the modification package to alter the diesel generator air start system (M-12-2-88-06). The modification was the result of a design weakness identified as a result of the Safety System Functional Inspection conducted in 1988 by the licensee. The inspectors observed the physical work of the resupport of the air receiver drain piping and verified the work was performed by qualified workers and in accordance with approved instructions and drawings contained in the work package. Additionally, welder qualification records for those individuals welding the hanger supports were verified.

No violations or deviations were identified in this area.

7. Safety Assessment/Quality Verification (35502 and 40500)

a. On October 1, 1990, while Unit 2 was shutdown for a refueling outage and fuel was being moved from the vessel to the spent fuel pool, the licensee discovered that the fuel movement was out of sequence. Fuel moves were designated by the Nuclear Material Transfer Checklist (NMTC) in accordance with Dresden Technical Surveillance (DTS) 8471, "General Procedure For Fuel Transfers Involving the Reactor." Step 581 of the NMTC indicated that fuel assembly X2B067 at core location 45-46 was to be transferred to Spent Fuel Storage Pool (SFSP) location F2-A7. Instead, fuel assembly X2C113 at core location 43-46 was moved to that SFSP location during NMTC step 581. The error was noticed prior to movement of any other fuel assemblies and all fuel movement was halted. Safety significance was minimal since as this was offloading of fuel, a criticality concern did not exist. Further review indicated that poor communications and inattention to detail contributed to the event. The fuel assembly to be moved was the last fuel assembly in the control cell. The following step, 582, involved a transfer from a different core region. The Fuel Handling Supervisor went onto the fuel grapple to caution the fuel handling crew of this fact. The independent verifier and grapple operator were scheduled to swap duties starting with step 582. Therefore, following the caution just received about that step, the independent verifier was studying a core map in regard to step 582 instead of independently verifying step 581. The fuel handling error was discussed with the current and later the oncoming crew to emphasize the importance of attention to detail an proper independent verification. The independent verifiers were instructed to communicate to the grapple operator whether or not the proper fuel assembly was grappled prior to moving the assembly. (Before the event, positive communication was necessary only if the wrong assembly was latched.) Increased supervision to confirm the effectiveness of the independent verification was initiated. In addition, the licensee decided to expedite repairs to the core position indication system (CPIS) on the grapple which would have aided the fuel handlers to identify the correct assembly had it been entirely operable.

On October 2, 1990, despite the previous corrective actions, another fuel assembly mispositioning event occurred. An Electrical Maintenance Supervisor (EMS) was on the fuel grapple to observe the operation of the CPIS in preparation for repairs as discussed above. The independent verifier was discussing its operation with the EMS. Step 12 of Revision 2 of Part 7 of the NMTC prescribed movement of fuel assembly X2C160 at core location 25-28 to SFSP location F2-E1. The grapple operator instead moved fuel assembly A2D109 in core location 27-28. The independent verifier gave a cursory inspection of the core location and latched condition, while engaging in conversation with the EMS, and gave verbal permission to move the fuel assembly. The error was noted when moving the grapple to the next fuel assembly to be relocated and fuel loading was again halted. This event was again related to inattention to detail and lack of self-checking. A discussion involving management and the fuel handlers themselves was conducted to determine the best method of independent verification. It was determined that confusion still existed regarding the process the independent verifier followed during fuel moves including communications and the process was inadequately defined in appropriate procedures. In addition, external distractions were not adequately controlled on the grapple during fuel movement. A meeting was held between licensee management and all fuel handlers to stress the importance of attention to detail, independent verification and good communications. A temporary change was issued to DAP 7-7, "Conduct of Refueling Operations" to restrict grapple access during fuel movement. The CPIS was also repaired prior to resuming fuel movement. The licensee also planned to revise fuel handling procedures prior to the next refueling outage on Unit 3, currently scheduled for April 1991, to clarify the duties and responsibilities of the independent verifier and to establish compensatory measures when the CPIS is inoperable. Further corrective actions to address general concerns about events during the outage is discussed is paragraph 7.b.

Further review of past events, found two previous and similar fuel loading errors on January 10 and 12, 1989 during the last Unit 2 refueling outage. The licensee had determined the root cause of these events to be fuel handler inattention to detail. As a result, a memorandum had been issued to ensure an independent verifier visually verified the correct storage and core locations in addition to verifying fuel assembly latching. It also emphasized clear and concise communication. It was evident that this corrective action was insufficient to prevent the later October 1, 1990 event. Furthermore, the corrective actions from the October 1, 1990 event were also insufficient to prevent still another event on October 2, 1990. Inadequate corrective actions in response to the January 10 and 12, 1989 and October 1, 1990 fuel assembly mispositioning events is considered to be a violation (50-237/90023-08 (DRP)) of 10 CFR 50, Appendix B, Criterion XVI. The remaining unloading of fuel and the reloading of fuel during the current refueling outage following additional corrective actions did not result in any fuel assembly mispositioning errors.

b. As described elsewhere in this report, a number of events occurred during the Unit 2 refueling outage which were indicative of personnel performance problems such as poor communications and inattention to detail. These included two fuel bundle mispositioning events, an inadvertent automatic start of a core spray pump, a reactor cavity overflow event, disassembly of the wrong feedwater isolation check valve, inadvertent draining of a diesel generator fuel oil day tank, inadvertent diesel generator start and loading and several other events which are either covered in other inspection reports or were not related to reactor or radiation safety. It appears that the frequency of these types of problems increased dramatically during the Unit 2 refueling outage as compared to the last Unit 3 refueling outage. This was not a contractor control problem since the majority of events involved station personnel across several organizational boundaries. Licensee management recognized the adverse trend and instituted specific action to address personnel performance problems on a generic basis. These generic actions included special meetings to emphasis these events and management expectations of priorities to workers. Outage work activities were temporarily reduced (substantially on Sundays) to ensure workers were well rested and to emphasize attention to detail over schedule. In addition, a self-check program, recently implemented for operations personnel in response to a previous violation, was expanded to the entire site. A third party review team was requested to review past events for any new insights. The inspectors observed substantial management involvement to address the problems.

c. While observing performance of a quality control (QC) hold point in work request 95491, the inspector noted that the Q.C. inspector identified that the step was being performed incorrectly. The work request involved repairing of the air receiver tank relief valve 2A2 for the Unit 2 diesel generator. The particular QC hold point was on a step for bench setpoint adjustment of the relief valve. The mechanics had set the relief valve to "pop" fully open within the set pressure band delineated in the procedure. However, a relief valve will initially open part way in order to relieve pressure back to acceptable system pressure. If system pressure continues to rise the valve will fully open or pop. As it was set, the valve would have relieved below the specified tolerance band. The QC inspector explained this to the mechanics who then correctly adjusted the setpoint. Followup to this problem was provided by completion of a QC Inspection Feedback Sheet by the QC inspector. This document is sent to the involved department to inform departmental supervision of the problem so that any actions they feel appropriate can be taken. However, this methodology did not provide a tracking mechanism to ensure that the root cause is identified and appropriate corrective action is taken. The licensee stated that this mechanism was instituted to address lesser problems that would not be important enough to identify through other available problem reporting programs such as deviation reports. This is considered to be an unresolved item (50-237/90023-09 (DRP)) pending further review of the administrative guidance regarding these feedback sheets, types of problems identified in these feedback sheets, threshold criteria for other deviation reporting methods and the adequacy of actions taken by various departments in response to these feedback sheets.

d. The inspector observed the scram/engineered safety features (ESF) actuation reduction main committee meeting held on November 2, 1990. The committee reviewed the status of corrective actions that were being instituted in response to previous scrams and ESF actuations to prevent further occurrences. In addition, a review and discussion of recent events was performed during the meeting to ensure adequacy of planned corrective actions from a scram/ESF reduction standpoint. The status of BWR Owners Group Scram Frequency Reduction Recommendation Tracking System items and a recent Owners Group conference report were also discussed. This was viewed by the inspectors as a genuine effort to incorporate lessons learned from other facilities to prevent adverse occurrences. The inspectors regarded the licensee's scram/ESF reduction activities to be beneficial in light of the smaller number of scram/ESF actuations occurring in 1990 compared to the previous year.

One violation and no deviations were identified in this area.

8. <u>Report Review (90713)</u>

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

9. <u>Unresolved Items</u>

Unresolved items are matters about which more information is required in order to ascertain whether it is an acceptable item, an open item, a deviation or a violation. Unresolved items disclosed during this inspection are discussed in paragraphs 4.f, 4.g, 5.a.3, 5.b.2 and 7.c.

10. <u>Exit Interview</u>

The inspectors met with licensee representatives (denoted in Paragraph 1) on November 16, 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.

Commonwealth Edison
1400 Opus Place
Downers Grove, Illinois 60515

December 14, 1990

Mr. A. Bert Davis
Regional Administrator, Region III
U.S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, IL 60137

Subject: Dresden Station Units 2 and 3
Report Pertaining to
Unresolved Item 50-237/90023-06
NRC Docket Nos. 50-237 and 50-249

References: (a) W. Shafer (NRC) letter to C. Reed (CECo), dated December 7, 1990.

(b) Conference Call on November 14, 1990 between CECo (K. Peterman, E. Skowron, J. Lindahl) and NRC (D. Hills, J. Holmes).

Mr. Davis:

Reference (a) transmitted Inspection Report 50-237/90023 and 50-249/90023 for Dresden Station. The Inspection Report contained an Unresolved Item (50-237/90023-06) regarding low electrolyte levels identified in six (6) emergency lighting units. As requested by your staff in the Reference (b) teleconference, attached is the investigation report performed by Dresden Station on this unresolved item. This report, which is the station's Deviation Report, includes an event summary, a root cause evaluation and corrective actions.

Additionally, the requested emergency lighting drawings have been provided directly to Mr. J. Holmes of your staff.

Please direct any questions or comments on this matter to this office.

Respectfully,

Milton H. Richter

for T.J. Kovach
Nuclear Licensing Manager

Attachment: Dresden Station Deviation Report 12-2/3-90-123

cc: B. Siegel - NRR Project Manager
NRR Document Control Desk
D. Hills - Senior Resident Inspector, Dresden
J. Holmes - Region III Inspector

MR:TK:lmw
ZNLD652/7

ATTACHMENT

DRESDEN STATION DEVIATION REPORT 12-2/3-90-123

DEVIATION REPORT

DVR NO.			
12 -	2/3 -	90 -	123
STA	UNIT	YEAR	NO.

Form Re

PART 1 | TITLE OF DEVIATION Inadequate Safe Shutdown Emergency Light Electrolyte Levels Due to Management Deficiency

OCCURRED 10/19/90 DATE 1000 TIME

SYSTEM AFFECTED 4100 Fire Protection

PLANT STATUS AT TIME OF EVENT

MODE Refuel (Run) POWER(%) 0 (97)%

N/A WORK REQUEST NO.

TESTING [ ] YES [X] NO

DESCRIPTION OF EVENT

At 1000 hours on October 19, 1990 the NRC Resident Inspector notified the Electrical Maintenance Department (EMD) Master Electrician of possible deficiencies regarding several Safe shutdown (SSD) emergency lights. The lights were installed to meet the requirements of 10CFR50 Appendix R, Section III.J. The EMD immediately responded to these concerns by re-performing the routine maintenance check on the SSD emergency lights in accordance with Dresden Electrical Surveillance (DES) 4153-2, Monthly Emergency Lighting Monthly Inspection. To verify operability, eight hour battery discharge tests were performed on selected emergency lights which were found to have low electrolyte levels.

As the SSD emergency lights are not controlled by the Technical Specifications or Dresden Administrative Technical Requirements (DATR). No Limiting Conditions for Operations (LCO) were entered into or exceeded during this event.

POTENTIALLY SIGNIFICANT EVENT PER NOD DIRECTIVE OP.10 [ ] YES [X] NO

10CFR50.72 NRC RED PHONE NOTIFICATION MADE [ ] 1 HOUR [ ] 4 HOUR ______ TIME [X] NO

Mark Churilla RESPONSIBLE SUPERVISOR 11/13/90 DATE

PART 2 | OPERATING ENGINEER'S COMMENTS

Tech Staff and EMD are working on long term corrective actions. This Deviation Report was issued as a matter of documentation and to establish a detailed review.

[X] NON REPORTABLE EVENT

[ ] 30 DAY REPORTABLE/10CFR

[ ] 5 DAY REPORT PER 10CFR21

[ ] ANNUAL/SPECIAL REPORT REQUIRED

A.I.R. #______________

L.E.R. #______________

NOTIFICATION N/A REG ON III ______ DATE ______ TIME

N. Kalivianakis NSD 11/14/90 DATE 1547 TIME

[ ] CECO CORPORATE NOTIFICATION MADE IF ABOVE NOTIFICATION IS PER 10CFR21

TELECOPY N/A CECO CORPORATE OFFICER ______ DATE ______ TIME

PRELIMINARY REPORT COMPLETED AND REVIEWED B. A. Zank OPERATING ENGINEER 11/14/90 DATE

INVESTIGATION REPORT & RESOLUTION ACCEPTED BY STATION REVIEW MC Strait 12/14/90 DVandell

Jane Williams 12/14/90

RESOLUTION APPROVED AND AUTHORIZED FOR DISTRIBUTION Lawrence F. Gerner for STATION MANAGER 12/19/90 DATE

86-5176 (Form 15-52-1) 4-12-90

DVR/87

DEVIATION INVESTIGATION REPORT (DIR)

Form Rev

Facility Name	PAGE
Dresden Nuclear Power Station, Unit 2/3	1 OF 0

Title Inadequate Safe Shutdown Emergency Light Electrolyte Levels Due to Management Deficiency

EVENT DATE			DIR NUMBER					REPORT DATE			OPERATING MODE	N
MONTH	DAY	YEAR	STA	UNIT	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	POWER LEVEL	0 9 7
1 0	1 9	9 0	1 2	2 3	9 0	— 1 2 3 —	0 0	1 2	1 1	9 0		

CONTACT FOR THIS DIR

NAME	TELEPHONE NUMBER AREA CODE	
Eric Skowron, Technical Staff Engineer Ext. 2485	8 1 5	9 4 2 - 2 9 1 2

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
E	K P	B T R Y	T 0 8 3	N					

SUPPLEMENTAL REPORT EXPECTED		EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
YES (if yes, complete EXPECTED SUBMISSION DATE)	X NO				

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor - 2527 MWt rated core thermal power

Nuclear Tracking System (NTS) tracking code numbers are identified in the text as (XXX-XXX-XX-XXXXX)

EVENT IDENTIFICATION:

Inadequate Safe Shutdown Emergency Light Electrolyte Levels Due To Management Deficiency

A. CONDITIONS PRIOR TO EVENT:

Unit(s): 2 (3) Event Date: October 19, 1990 Event Time: 1000 Hours

Reactor Mode(s): N (N) Mode Name(s): Refuel (Run) Power Level(s): 0% (97%)

Reactor Coolant System (RCS) Pressure(s): 0 (997) psig

B. DESCRIPTION OF EVENT:

At 1000 hours on October 19, 1990, with Unit 2 shutdown in the Refuel mode and Unit 3 operating in the Run mode at 97% rated core thermal power, the NRC Resident Inspector notified the Electrical Maintenance Department (EMD) Master Electrician of possible deficiencies regarding several safe shutdown (SSD) emergency lights. The emergency lights in question were among those credited in the Dresden SSD Analysis report for meeting the requirements of Appendix R to 10CFR50, section III.J. The emergency lighting units were noted to have batteries with low water (electrolyte) levels, or to have an electrolyte density that indicated low charge or end of battery life. The EMD immediately responded to these concerns by conducting the routine maintenance check of SSD Emergency Lights in accordance with

FACILITY NAME	DIR NUMBER						PAGE
	STA	UNIT	YEAR		SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2/3	1 2	2 3	9 0	—	1 2 3	0 0	2 OF 0

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

Dresden Electrical Surveillance (DES) 4153-2, Monthly Emergency Lighting Inspection. Special attention was paid to recording "as found" electrolyte levels and other pertinent information about the emergency lighting unit during the performance of the surveillance. Attachment A identifies the "as found" condition of the fourteen worst case Unit 3 SSD emergency lighting units from the October 19, 1990 inspection. The units listed are those with electrolyte levels below the manufacturer's "add" line, or with unacceptable electrolyte specific gravity.

C. APPARENT CAUSE OF EVENT:

Due to the complex electro-chemical interactions of a lead-acid battery, its electrical charging system, and battery operation and maintenance, the root cause of the low battery water levels and other battery deficiencies could not be immediately ascertained. A controlled set of "as found" battery condition data was taken immediately after the event was identified. In order to determine the actual cause of the excessive water consumption found in some of the batteries it was concluded that a second set of "as found" battery condition data would be needed. The second set of "as found" data would permit trending of water consumption rates under known plant ambient conditions. DES 4153-2 was repeated thirty days after the October 19, 1990 test.

The following is a summary of the potential causes considered in evaluating the battery deficiencies:

a. High Ambient Temperature - The battery electrolyte, like water, will evaporate under relatively warm ambient conditions resulting in low electrolyte levels.

b. Battery End of Life - Battery end of life is marked by excessive water consumption, and low specific gravity. These characteristics will differ among batteries due to minor variations in product construction, the number of discharge/charge cycles over the life of the battery, the age of the battery, and any exceptional operating demands put on the battery.

c. Excessive Discharging/Charging - Excessive discharging and charging of the battery significantly decreases battery life due to cumulative damage to the battery plates during each successive discharge/charge cycle. Excessive discharging/charging may occur through deliberate use, a faulty Bharging system, or an internal or external short resulting in continuous simultaneous discharging/charging.

d. Cracked Battery Casing - A cracked battery case could result in leakage of the electrolyte out of the case. A cracked battery case could be caused by improper handling or accidental impact, product defect, or intense battery overheating due to a direct short.

e. Excessive Lead Sulphate Plating - Sulphate plating is an indication of battery end of life. This condition will increase water consumption, and decrease the electrolyte specific gravity. Sulphate plate shedding will exacerbate battery degradation if suphate flakes bridge the battery plates causing an internal short. Sulphate plating/shedding may occur as a result of discharging the battery with low (below the top of battery plates) electrolyte level.

f. Improper Maintenance - Failure to monitor and fill the battery electrolyte level is a plausable explanation of low electrolyte level.

FACILITY NAME	DIR NUMBER						PAGE
	STA	UNIT	YEAR		SEQUENTIAL NUMBER		REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2/3	1 2	2 3	9 0	—	1 2 3	—	0 0	3 OF (

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

The October 19, 1990 Inspection Revealed that most of the Unit 3 SSD emergency lighting units had batteries with electrolyte level below the "full" line. Electrolyte levels below the "add" line were noted in 13 of the 60 Unit 3 SSD emergency light batteries, and one battery was found to have dropped hydrometer discs (indicating low specific gravity) despite having an adequate electolyte level. Interviews with several of the Electricians who perform the DES 4153-2 procedure confirmed that the electrolyte level would not normally be topped off if the level was found to be above the "add" line, contrary to DES 4153-2 which specifically states that if the electrolyte level is below the "full" line, then distilled water is to be added to the "full" line. It should be noted, however, that the manufacturer's maintenance instructions permit the electrolyte level to float between the "full" and "add" lines.

Two of the fourteen emergency lighting units identified on October 19, 1990 (Nos. 354 and 355) had water levels below the "add" line and were also located in high radiation areas. Of these two, one of the batteries was completely dry. The batteries for both of these emergency lighting units were replaced without testing. The rooms in which these lighting units are located are also hot, and poorly lit. It is possible, therefore, that due to the poor inspection conditions, and the hurried circumstances in which the surveillance is performed, that the water levels were not being properly observed. This is supported by the fact that identification of the water line through the translucent battery casing is difficult even under ideal conditions.

As for the remaining twelve battery lights identified on October 19, 1990 with electrolyte levels below the "add" line, or with unacceptable specific gravity readings, these lighting units were located in areas of the plant which were easily accessible. Two units with low specific gravity, Nos. 351 and 332, were considered to be near end of life and were replaced without testing. Emergency Lighting Unit No. 352 was found to have an extremely low electrolyte level. This unit was also considered to be near end of life and was replaced without testing. Finally, nine lights with low electrolyte level successfully passed an eight hour discharge test.

Results of the second surveillance, which was conducted thirty days after the October 19, 1990 surveillance, showed that only one battery had a discernable water level change. This battery, No. 360, was considered to have been aging faster than the adjacent lights, but was still not approaching its normal end of life. An eight hour discharge test was performed on this light, and it was confirmed to still be acceptable. With the exception of battery No. 360 the electrolyte levels in the battery cases remained stable for a full thirty days. Therefore, the proximate cause of the October 19, 1990 "as found" water levels occurring from 1/8" to 3/4" below the "full" line is attributed to inadequate adherence to DES 4153-2. However, the underlying root cause was attributed to management deficiency in that EMD supervision provided insufficient direction to the Electricians performing the surveillance. It should also be noted that the EMD had recently been assigned this activity, and that during the interim the completed surveillance documentation had not been routed to the System Engineer for review. It was also concluded that enhancements to DES 4153-2 were needed.

D. SAFETY ANALYSIS OF EVENT:

Alternative or dedicated shutdown capability is provided for each specific fire area, as required by 10CFR50 Appendix R, Section III.L. Detailed SSD procedures, which are designed to account for loss of offsite power (LOOP) conditions, are provided for these activities. Emergency lighting units of eight hour rated capacity are provided in all areas needed for local operation of SSD equipment and in access and egress routes thereto, as required by 10CFR50 Appendix R Section III.J to support performance of SSD operations under LOOP conditions. This type of scenario is extremely unlikely due to extensive fire detection and suppression equipment.

The Unit 3 emergency lighting units that were observed to have insufficient electrolyte levels, i.e., below the "add" line, were subjected to an eight hour discharge test. The total of nine batteries that were tested remained lighted at the end of the discharge test. However, five battery units were replaced without being tested and conservatively can be assumed to have failed. Three of these lighting units were only trained on access and egress pathways and were not needed to support local operation of SSD equipment. Since the Operators are provided with flashlights the safety significance of these failures is greatly reduced. The remaining two failures were in the MO3-1301-2 and -3 Isolation Condenser valve rooms. During performance of the SSD procedures under LOOP conditions, the only action required in the -2 valve room is to verify that the valve is open; in the -3 valve room the valve must be throttled to control reactor cooldown rate. Operation of these Isolation Condenser valves can be easily accomplished with the illumination provided by a flashlight.

In addition to re-performing the routine maintenance surveillance, battery discharge testing was performed on a random sample of twenty-five percent of all accessible Dresden SSD emergency lights. This testing was performed in order to demonstrate the reliability of the SSD emergency lighting system. A total of 43 lights were tested, with only two lights failing to remain illuminated for the full eight hours. As for the two lights that failed, these were Unit 2 emergency lights, and are not required to support SSD since Unit 2 is in cold shutdown for a refueling outage. Moreover, these two lights illuminated only access and egress pathways and not SSD equipment or panels. The lights remained lit for at least 4 hours, which would have supported initial access and egress if they were needed. Based upon these results EMD has concluded that the operability of the SSD emergency lighting is reasonably assured. Therefore, the safety significance of this event is considered to be minimal.

E. CORRECTIVE ACTIONS:

The EMD conducted a special inspection of the Unit 3 SSD emergency lights under DES 4153-2. Performance of this procedure identified 14 emergency lights that had either low specific gravity (dropped hydrometer discs), or electrolyte level which was below the "add" line, or both (see Attachment A). Of these fourteen lights, five were deemed inoperable without test or evaluation and were replaced. The remaining nine lights were proven to be operable by the successful completion of eight hour battery discharge tests. Trending was also performed on the Unit 3 SSD emergency lights for a period of approximately one month. This study did not identify any unusual maintenance problems or electrolyte consumption characteristics.

The EMD also conducted a special inspection of the Unit 2 SSD emergency lights under DES 4153-2. Of the 152 lights that were inspected two lights had low specific gravity, two had indications of a possible internal short, and one emergency lighting unit battery had non-uniform electrolyte consumption between battery cells. The batteries for all of these emergency lighting units were promptly replaced. The Unit 2 SSD emergency light inspection also identified seven units with electrolyte levels below the "add" line. Of these five were replaced without testing. The safety significance of these degraded, or potentially degraded, emergency lights is considered minimal since Unit 2 is in cold shutdown for a refueling outage.

The two remaining Unit 2 emergency lighting units with low electrolyte levels were included in a group of 28 randomly selected accessible Unit 2 emergency lights that were discharge tested. These lighting units, together with the 15 units that were discharge tested on Unit 3, make up a sum total of 43 lights that were discharge tested; that is, twenty-five percent of all accessible emergency lights. Two of the Unit 2 emergency lights failed to remain illuminated for the full eight hours. However, the lights remained lit for at least four hours. These two emergency lighting unit batteries were replaced following the test.

Because (1) a significant majority of all inspected SSD emergency lighting units were found to be acceptable, (2) any emergency lighting units that were found to be degraded or potentially degraded were promptly replaced, and (3) the relative success of the eight hour battery discharge testing, the Station has concluded that the operability of the emergency lighting system is reasonably assured.

The following enhancements will be added to the SSD emergency lighting maintenance program:

1. A surveillance cover sheet requiring signature of all mechanics performing the test, and technical review by the EMD Supervisor and the cognizant Technical Staff Engineer will be utilized on all future SSD emergency light maintenance surveillances.

2. The DES 4153-2 maintenance surveillance will be revised by the EMD with assistance from the System Engineer as follows (237-200-90-12301):

   a. The procedure will include acquisition of "as found" and "as left" electrolyte levels.

   b. The procedure will clarify the conditions when water must be added to the battery.

   c. The procedure will be split between SSD and balance of plant (BOP) emergency lights in order to exercise better control over the SSD lights.

   d. A summary of possible indications of battery degradation will be added. The indications to be inspected for may include excessive water consumption, differences in electrolyte levels between battery cells, bubbling, differences in specific gravity between battery cells, etc.

   e. DES 4153-2 will continue to be performed monthly. However, EMD with the assistance of the Technical Staff will investigate the possibility of extending the surveillance interval. This change will be subject to upgraded maintenance and adequate technical justification.

3. The Technical Staff will investigate the possibility of relocating emergency light battery cabinets out of high radiation areas (237-200-90-12302).

4. An "as found" eight hour battery discharge test will be developed b/ the EMD with the assistance of the System Engineer for the Dresden SSD emergency lights. Testing for each SSD battery light will then be performed by the EMD once per operating cycle (237-200-90-12303).

F. PREVIOUS EVENTS:

There were no previous events of this type.

G. COMPONENT FAILURE DATA:

Manufacturer	Nomenclature	Model Number	Mfg. Part Number
Teledyne Inc.	Emergency Lights	S6L100-80	*S6L100-80

This equipment is not NPRDS reportable, therefore, an industry wide NPRDS data base search was not performed.

NOTE: The asterisk in the mfg. part number indicates the number of lamps that the lighting unit comes with. i.e. 0,1,2,3.

DEVIATION INVESTIGATION REPORT TEXT CONTINUATION

Form Rev

FACILITY NAME	DIR NUMBER						PAGE		
	STA	UNIT	YEAR		SEQUENTIAL NUMBER		REVISION NUMBER		
Dresden Nuclear Power Station, Unit 2/3	1 2	2 3	9 0	—	1 2 3	—	0 0	6 OF	0

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

ATTACHMENT A

UNIT 3 SAFE SHUTDOWN EMERGENCY LIGHT INSPECTION RESULTS, OCTOBER 19, 1990

BATTERY #	AS FOUND	AS LEFT	ILLUMINATES	COMMENTS
354	-1.5"	REPLACED	EQUIPMENT	NOTE 1 (BELOW) Illuminates Valve M03-1301-3
355	EMPTY	REPLACED	EQUIPMENT	HIGH RADIATION AREA Illuminates Valve M03-1301-2
351	+.5"	REPLACED	PATH	HYDROMETER DISCS DROPPED
360	-.75"	FILLED	PANEL	PASSED 8 HOUR DISCHARGE TEST
358	-.5"	FILLED	RACK	PASSED 8 HOUR DISCHARGE TEST
331	-.25"	FILLED	PANEL	PASSED 8 HOUR DISCHARGE TEST
353	-.5"	FILLED	PANEL	PASSED 8 HOUR DISCHARGE TEST
337	-.25"	FILLED	EQUIPMENT	PASSED 8 HOUR DISCHARGE TEST
342	-.5"	FILLED	PANEL	PASSED 8 HOUR DISCHARGE TEST
330	-.25"	FILLED	PATH	PASSED 8 HOUR DISCHARGE TEST
349	-1"	FILLED	PATH	PASSED 8 HOUR DISCHARGE TEST
352	-3"	REPLACED	PATH	REPLACED DUE TO EXCESSIVELY LOW ELECTROLYTE LEVEL
332	-1"	REPLACED	PATH	HYDROMETER DISCS DROPPED
335	-.5"	FILLED	PATH	PASSED 8 HOUR DISCHARGE TEST

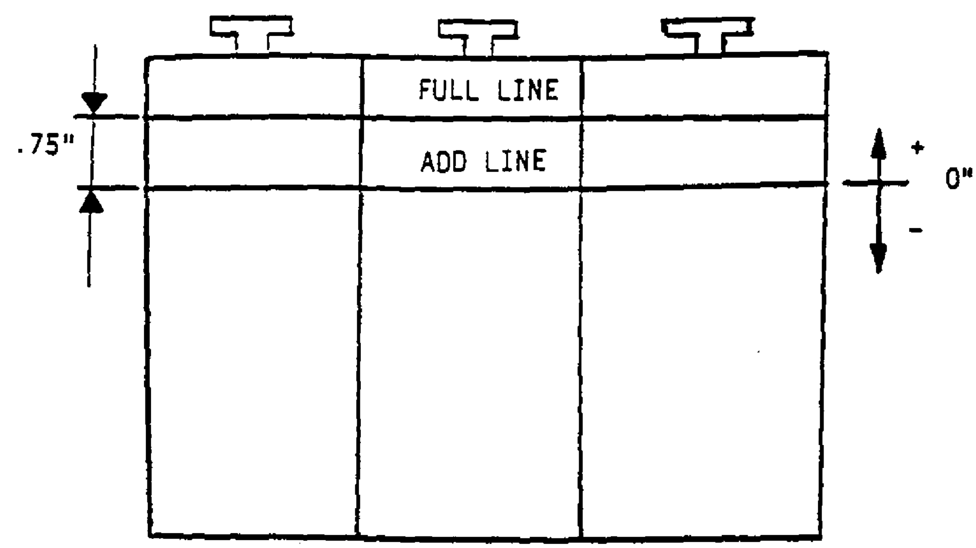
NOTE 1: THIS EMERGENCY LIGHT IS LOCATED IN A HIGH RADIATION AREA. THE BATTERY WAS REPLACED RATHER THAN TESTED IN PLACE DUE TO ALARA CONSIDERATIONS.

DEVIATION INVESTIGATION REPORT TEXT CONTINUATION

Form Rev

FACILITY NAME	DIR NUMBER						PAGE		
	STA	UNIT	YEAR		SEQUENTIAL NUMBER		REVISION NUMBER		
Dresden Nuclear Power Station, Unit 2/3	1 2	2 3	9 0	—	1 2 3	—	0 0	7 OF	0

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]



TYPICAL MODEL 3100S SIX VOLT BATTERY

Commonwealth Edison
1400 Opus Place
Downers Grove, Illinois 60515

January 7, 1991

Mr. A. Bert Davis
Regional Administrator - RIII
U.S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, Il 60137

Subject: Dresden Nuclear Power Station Units 2 and 3
Response To Notice of Violation Contained in
Inspection Report 50-237/90023; 50-249/90023
NRC Docket Nos. 50-237 and 50-249

Reference: W. D. Shafer letter to Cordell Reed dated
November 28, 1990 transmitting NRC Inspection
Report 50-237/90023; 50-249/90023

Dear Mr. Davis:

This letter provides the Commonwealth Edison Company (CECo) response (attached) to the subject three Level IV violations transmitted by the referenced NRC Inspection Report for Dresden Station. The three violations identified were: 1) inadequate training to assure satisfactory knowledge of plant administrative requirements, 2) the failure to follow procedures and instructions and 3) inadequate corrective actions with regard to fuel bundle mispositioning events. CECo has reviewed the Notice of Violations and in all but one example agrees that the violations occurred as described. The corrective actions detailed in the response will bring the Station into compliance and will prevent similar violations from occurring.

CECo recognized a negative trend in human performance, personnel-related events and views this as a serious matter. Actions were taken to address each event, but we also have taken additional timely, broad, comprehensive actions to address the identified negative trend. These actions are beyond those in the detailed responses to the Notice of Violation and are listed in Attachment A.

If your staff has any questions or comments concerning this letter, please refer them to Rita Radtke, Compliance Engineer at 708/515-7284.

Very truly yours,

T. J. Kovach
Nuclear Licensing Manager

cc: B.L. Siegel, Project Manager, NRR
D. E. Hills, Senior Resident Inspector
NRR Document Control Desk

Attachment

/scl:ID707:1

ATTACHMENT A

Additional actions taken to address human performance, personnel-related events:

- A meeting was held with all supervisors (CECo & Contractor) on October 17, 1990 to raise overall onsite awareness. Each Supervisor was required to take notes during the meeting, meet with those employees he supervises and return his notes with names of those he met with by October 18, 1990.
- A station "Self Check" initiative, called VerAntSO, was introduced the week of October 22, 1990. VerAntSO is an acronym used to remind everyone of the self-check concept and stands for Verify, Anticipate, Stop and Observe.
- An INPO assist visit to review Human Performance activities was requested and performed on October 25 and 26, 1990.
- The CECo Performance Assessment Department performed an overview of outage concerns during the week of October 22, 1990.
- A licensed individual from Nuclear Quality Programs Department from another CECo station performed an overall review of in-plant activities during the week of October 22, 1990.
- An in-plant walkdown and independent verification of one hundred (100) out-of-services was performed to verify proper isolation of equipment for maintenance activities.

RESPONSE TO

NOTICE OF VIOLATION

VIOLATION 1

10 CFR 50, Appendix B, Criterion II, as implemented by Commonwealth Edison's "Quality Assurance Program" requires indoctrination and training of personnel performing activities affecting quality as necessary to assure that suitable proficiency is achieved and maintained.

Contrary to the above, indoctrination and training of personnel performing activities affecting quality was inadequate in assuring proficiency was achieved and maintained as to administrative requirements as indicated in the following examples:

a. Lack of operations personnel knowledge of Dresden Administrative Procedure (DAP) 7-5, "Operating Logs and Records," Revision 8, and Dresden Operating Abnormal (DOA) Procedure 902-5 G-2, Revision 3, requirements for maintaining the Control Rod Drive Accumulator High Water/Low Pressure Alarm Log (AHWLPAL) resulted in the AHWLPALs for both units not being maintained between April 1990 and August 3, 1990. As such the licensee's program to identify repeat failures of accumulator alarms was not effective during that time period (50-237/90023-01a (DRP)).

b. Lack of technical staff personnel knowledge regarding recognizing and processing conditions adverse to quality resulted in a failure to properly identify a procedural nonadherence involving maintenance of the AWHLPAL when discovered in May 1990. Because of this, corrective actions to prevent recurrence were not taken at that time. (50-237/90023-01b (DRP)).

This is a Severity Level IV violation (Supplement I).

DISCUSSION

On December 8, 1989, DAP 7-5, Revision 8 was approved. This procedure established an Accumulator High Water/Low Pressure Alarm Log (AHWLPAL). On the same day, a revision to the Unit 2(3) Operators Daily Surveillance Log (Appendix A) was approved which removed the weekly Control Rod Drive Accumulator Log from Appendix A so that there would not be two procedures recording the same information. The intent of the AHWLPAL was to maintain an ongoing record of Control Rod Drive Accumulator Alarms in order to identify problem accumulators. Either the AHWLPAL or the Control Rod Drive Accumulator Log (removed from Appendix A) would have been adequate for documenting Control Rod Drive Accumulator High Water/Low Pressure Accumulator Alarms. An AHWLPAL Book was established at each Unit Operator's Desk.

The on-shift licensed personnel did not receive formal instruction or notification as to the maintenance of the AHWLPAL during the day-to-day operation of the plant. Therefore, the implementation of the AHWLPAL was only partly accomplished by revising the procedures. The on-shift licensed personnel, responsible for maintaining the AHWPAL, did not receive training on this program.

The Technical Staff System Engineer learned in early May 1990 that the AHWLPAL was not being properly maintained as required by DAP 7-5 and realized that either the operators would have to be trained on the use of the log or that the program would have to be revised. During this same time period, the Operations Department was implementing a program to independently verify accumulator valving operations. This requirement was to be implemented by having the independent verifier sign the AHWLPAL log book. To resolve these two unrelated concerns in a coordinated manner, it was decided to place the AHWLPAL back into Appendix A. This revision to DAP 7-5 took longer than expected because of other changes to the procedure that were not related to the AHWLPAL. It took three months to resolve all of the issues with DAP 7-5. On August 30, 1990, the requirements for the AHWLPAL were transferred from DAP 7-5 back to the Unit Operator's Daily Surveillance Log, Appendix A, at which time CRD accumulator logging was resumed.

Action to correct the problem was taken, but it was not documented through the use of DAP 9-12, "Procedural Adherence Deficiencies." The System Engineer was not aware that DAP 9-12 should have been used as the mechanism to document this need for corrective action.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

The logging of accumulator alarms was transfered back to Appendix A on August 30, 1990. Since that date all accumulator alarms have been logged.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. The Operations Department, with assistance from the Training Department and the Technical Staff, will develop a method to ensure that when procedural changes are made that alter the day-to-day routine of licensed operators, a review is made to determine what training should be completed to properly implement the change. This methodology will be in-place by March 31, 1991.

2. DAP 9-12 will be tailgated to all station personnel by February 7, 1991. Emphasis will be directed to its purpose and use.

3. A number of events, occurring during the past six months, have indicated that the knowledge level of station personnel with regard to the contents of various Dresden Administrative Procedures is less than desired. To raise the station personnel knowledge level of the contents of the Dresden Administration Procedures, the Station's ongoing training program will be reviewed to verify that all personnel involved in activities addressed in each administrative program/procedure are appropriately trained. A matrix of Dresden Administrative training requirements will be produced by January 31, 1991 and appropriate changes will be made to the ongoing programs by June 30, 1991.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on August 30, 1990 at which date all accumulator alarms were properly logged.

VIOLATION 2

10 CFR 50, Appendix B, Criterion V, as implemented by Commonwealth Edison Company's Quality Assurance Program, requires that activities affecting quality be accomplished in accordance with documented instructions, procedures or drawings.

Contrary to the above, activities affecting quality were not accomplished in accordance with documented instructions, procedures, or drawings in the following examples:

This in a Severity Level IV violation (Supplement I).

EXAMPLE a

Dresden Operating Procedure (DOP) 1900-3, "Reactor Cavity-Dryer Separator Storage Pit Fill and Operation of the Fuel Pool Cooling and Cleanup System During Refueling," Revision 8, requires constant communication between the refueling floor and the control room while filling the reactor vessel. Constant communication between the refueling floor and the control room was not maintained while filling the Unit 2 reactor vessel on October 14, 1990, resulting in the overfilling of the vessel into the ventilation ducts and contamination of various areas of the third and fourth floors of the reactor building. (50-237/90023-2a (DRP))

DISCUSSION

On October 13, 1990 the reactor cavity flooding evolution began. Prior to beginning the evolution, a Fuel Handling Supervisor had agreed to monitor reactor cavity level from the refueling floor. As cavity flooding progressed, the Fuel Handling Supervisor reported on the cavity level. At 0330 hours on October 14, 1990, the Fuel Handling Supervisor informed Operations that he was leaving and that the level was approximately 1 1/2 feet below the bottom of the ventilation openings. From this point on, the reactor cavity water level was no longer being continuously observed. Later, the Unit 2 NSO dispatched the Equipment Attendant (EA) to visually observe the cavity level. The EA erroneously reported that the level was 16 inches below the bottom of the ventilation openings.

A short time later, the control room received annunciator, "Fuel Pool High Level." The NSO immediately closed the Feedwater Low Flow Valve and dispatched another EA to reject water from the fuel pool cooling system to the Condensate Storage Tank. A Shift Supervisor then proceeded to the fourth floor of the Reactor Building where he saw water coming from the ventilation ducts.

DOP 1900-3 contains a precaution: "Maintain constant communications between the refueling floor and the Control Room while filling the reactor head cavity and the dryer/separator pit to prevent overflow into the ventilation ducting." This was not followed from the time the Fuel Handling Supervisor left the refueling floor until the alarm was received in the control room.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. This event was included in a series of meetings conducted on October 17, 1990 by the Station Manager and attended by all line supervisors of CECo and Contractor organizations on site. The purpose of the meetings was to increase everyone's awareness of several recent events involving personnel error and to require subsequent meetings between these supervisors and all employees to raise the overall on-site awareness level of the need for increased attention to detail.

2. A posted operator aid was revised showing the level of the bottom of the ventilation openings to be 469 inches instead of the previously erroneous value of 476 inches.

3. Operations personnel involved in this event were counselled on the importance of procedure adherence.

4. Procedural adherence was addressed in a Shift Engineer's meeting held on October 24, 1990. Shift Engineers were instructed that procedures must be consulted and adhered to for all complex, unique, or infrequent evolutions.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. DOP 1900-3 will be revised to clarify when continuous visual monitoring is required when flooding the refuel cavity. The requirement for visual monitoring will be specified so that continuous monitoring will not be required for slow moving evolutions when level is more than three feet from the final desired level. The procedure will be revised by March 31, 1991.

2. The Instrument Maintenance Department will revise DIP 0260-01, Figure 1 to correctly depict the bottom of the cavity ventilation openings at 469 inches by March 31, 1991.

3. To aid visual estimates of water level, the Technical Staff will evaluate methods of providing a graduated scale in the Reactor cavity and in the Dryer/Separator pit for Units 2 and 3. An acceptable method will then be implemented by March 31, 1991.

4. This event was reviewed by licensed operators during Cycle 8 of continuing training. This was completed on December 7, 1990. It will be covered for non-licensed operators by March 1, 1991.

5. The EA involved in this event developed an article for the Station's monthly newsletter, discussing the importance of attention to detail, procedural adherence, and the concept of self-checking one's actions.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on October 14, 1990 when the reactor cavity flooding evolution was completed.

EXAMPLE b

Specific practices required by DAP 3-5, "Out of Service and Personnel Protection Cards," Revision 22, were not followed as to preparation, review, approval, documentation and independent verification in the removal and return to service of the Unit 2 diesel fuel oil day tank drain valve on October 20, 1990. This resulted in the inadvertent draining of the day tank when the drain valve was placed in the incorrect position. (50-237/90023-02b (DRP))

DISCUSSION

In preparation for the cleaning of the Unit 2 Diesel Generator Main Fuel Oil Storage Tank, the Diesel Fuel Oil Transfer Pump Suction valve was shut and the Fuel Oil Day Tank Drain valve was checked to be shut by a member of the Operations Staff on October 8 or 9, 1990. "Do Not Operate" tags supplied by the storage tank cleaning contractor were placed on the valves. No CECo Out-of-Service was written for the tank cleaning.

On October 20, 1990, between 10:30 and 11:00 am, the same member of the Operations Staff opened the Transfer Pump Suction Valve. In addition, he opened the Day Tank Drain Valve, even though he had checked that this valve was shut approximately 12 days prior. These valve manipulations were performed without the knowledge of on-shift Operations or procedural guidance.

At approximately 11:20 am on Saturday, October 20, 1990, the "Unit 2 Diesel Generator Day Tank Hi/Lo Level" alarm was received in the Control Room. At approximately the same time, two members of the Technical Staff were in the vicinity of the diesel generator room and observed a strong odor of fuel oil. Upon entering the room, they noticed fuel oil on the floor.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. A member of the Technical Staff traced the source of the fuel spill to the drain on the Unit 2 Fuel Oil Day Tank, found drain valve 2-5212-500 approximately one to two turns open and closed the valve. Approximately 600 gallons of fuel oil were spilled.

2. The involved Operations Supervisor was counseled on the need to interact with Operations Department shift personnel to ensure that all valves necessary to adequately isolate a component are included on the appropriate Out-Of-Service. The involved individual was reminded that unauthorized valve manipulation is against plant policy and could lead to personnel injury or equipment damage.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCE

1. The Day Tank drain valves on all three emergency diesels were locked shut. The Locked Valve Checklist and System Checklist will be revised to include the Day Tank Drain on all emergency diesels in the locked closed position by March 31, 1991.

2. The details of this event were reviewed with all station personnel at the October 18, 1990 tailgate meetings, emphasizing the need to properly use the Out-Of-Service program and the hazards of unauthorized equipment manipulations.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on October 20, 1990 when the drain valve was closed.

EXAMPLE c

DAP 7-14, "Control and Criteria For Locked Equipment and Valves," Revision 2, requires manual valves in the flowpath of systems required for plant shutdown during post-accident situations or which provide a controlled path to the environs, including primary and secondary containment isolation valves to be locked. Prior to November 1990, manual valves including the Units 2, 3 and 2/3 diesel generator service water three-way valves and the Units 2 and 3 drywell manifold sampling system containment isolation valves were not locked or designated to be locked (50-237/90023-02c (DRP)).

DISCUSSION

The Diesel Generator Service Water flow reversal valves were erroneously excluded from the locked valve checklist. This was due to the valves having a mechanical locking device which prevents the valves from repositioning. The Station believed that the locking device (which does not have a keyed lock) fulfilled the administrative requirements of the locked valve program.

CECo does not believe that a requirement existed to "lock closed" the 2(3)-8507-500 through 521 Drywell Air Sample Valves. The USNRC had, on two separate occasions, the opportunity to review and assess the acceptability of those valves. On each occasion they found the design to be acceptable:

1. In response to NUREG 0578, in a letter dated February 25, 1980, CECo supplied information on primary containment isolation valves. An excerpt from that letter reads as follows, "All non-essential systems that provide a possible open path out of the primary containment were found to be either isolated by isolation signals, by check valves that would prevent flow out of the containment, by manual valves that are normally closed during reactor operation, or as in the case of instrument lines by closed piping systems." Included were the 2(3)-8507-500 through 521 valves with their classification (non-essential) and a sketch showing their configuration. The USNRC, in a letter dated March 5, 1980, responded, "We conclude that the licensee has completed a re-determination of which containment isolation penetrations are essential or non-essential. All non-essential lines are either automatically isolated by diverse signals or technical justification has been provided. Modifications have been made to prevent inadvertent re-opening of isolation valves. Based on the above, we find that the licensee has satisfied the requirements of this item."

2. Various correspondence exists documenting the scope and depth of the USNRC review of SEP Topic VI-4, "Containment Isolation Systems." An NRC letter dated December 18, 1981, transmitted a draft SER on the topic and requested that CECo provide comments and additional information. CECo's response of May 21, 1982 provided information on the 2(3)-8507-500 through 521 valves. Based upon that response, the NRC issued their final SER on September 24, 1982. Table I of that SER provides a list of valves which they reviewed; the 2(3)-8507-500 through 521 valves are included on that list. A section of the SER titled, "Administrative Control," identifies valves which have inadequate administrative controls and which should be listed as "locked closed" instead of "normally closed." These valves are listed in Table II; the 2(3)-8507-500 through 521 valves are not included. Another section titled, "Manual Isolation Valves," lists other valves which should be in a "locked closed" position; once again the 2(3)-8507-500 through 521 valves are not included.

Although the basis of acceptability for these valves being "normally open" or "normally closed" is not provided in the SERs, it presumably is due to the Drywell Air Sample system being a closed loop system. In any case, the NRC reviewed these valves as part of post-TMI and SEP, and did not require them to be "locked closed."

The Inspection Report and Notice of Violation reference a November 18, 1982 commitment to "review all containment penetrations in the plant and not limit the scope to Table II in the SER." DAP 7-14, "Control and Criteria for Locked Equipment and Valves," is also referenced. One of the DAP 7-14 criteria for locked valves is, "Manual valves which provide a controlled path to the Environs, including Primary and Secondary Containment isolation valves." Since the Drywell Air Sample system is a closed loop system, leakage past these valves would not provide an uncontrolled path to the environs. CECo does not believe that operation of a system consistent with the plant's original design basis and in accordance with NRC SERs and Station administrative programs constitutes a violation of NRC requirements.

During a recent investigation into the use of a temporary sample pump to obtain drywell air samples (in which the Drywell Air Sample system's closed loop was broken), questions arose relative to the ability of the original Drywell Air Sample system to withstand seismic and accident conditions. In view of this recent information, CECo is re-assessing the acceptability the system. Past performance of the system has shown only limited usefulness in its ability to locate sources of leakage into the drywell. With the recent approval of the Station's Generic Letter 88-01 submittal (in which no credit was taken for the Drywell Air Sample system) it is believed that the system may be removed. Final resolution of the Drywell Air Sample system is expected in February, 1991. As an interim measure, valves 2(3)-8507-500 through 521 have been taken out-of-service closed. These valves will remain controlled by the out-of-service or locked closed in accordance with DAP 7-14 as long as the system remains in place. Since no method of locking these valves presently exists, work requests have been written to provide a means of locking them. The valves will be added to the locked valve checklist and locked as appropriate prior to clearing the out-of-service on these valves.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

Temporary Procedure Change 90-408 was written against Dresden Operating Procedure (DOP) 040-M3, "Locked Valve List: Accessible During Operations," adding the Diesel Generator Service Water flow reversal valves to the Locked Valve List. The valves were also locked at that time.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. DOP 040-M3 will be revised by March 31, 1991 to include the Diesel Generator Service Water three-way valves.

2. A review of other valves with mechanical locking devices will be conducted to assure that they are not being inappropriately excluded from the locked valve program by March 31, 1991.

3. DAP 7-14 criteria will be reviewed and revised as necessary to assure the locked valve criteria are easily understood by station personnel. This will be accomplished by March 31, 1991.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on November 27, 1990 when the valves were locked into position.

EXAMPLE d

DAP 15-6, "Preparation and Control of Work Requests," Revision 0, requires work to be performed per repair manual(s), travelers/procedures, or work instructions provided in the work package. On October 15, 1990, work prescribed for disassembly of the Outboard Containment Isolation Feedwater Check Valve 220-62B was performed instead on Outboard Containment Isolation Feedwater Check Valve 220-62A (50-237/90023-02d (DRP)).

DISCUSSION

As a result of local leak rate tests (LLRTs) performed on September 24 and 30, 1990 on the 2-220-62A and 62B check valves, the decision was made to repair the valves. A maintenance pre-job briefing and ALARA pre-job briefing were performed on October 12, 1990 prior to proceeding to the work area for disassembly of the 62B check valve. The Maintenance Supervisor accompanied his crew to the work location and directed them to begin work on what he believed to be the 62B valve, but was actually the 62A valve.

Upon removal of the valve bonnet and seal ring, the valve body was found full of water and the valve disc stuck in the open position. All work was immediately stopped, the Maintenance Supervisor and Technical Staff were notified of the as found condition. Water was pumped from the valve body and work continued on valve decontamination, inspection and repair.

On October 17, 1990 a Radiation Protection Technician (RPT) surveyed the valve plug and seat. The RPT was concerned that work was being performed on the wrong valve and questioned the crew several times whether they were working on the correct valve. The crew indicated that they were sure they were on the correct valve and that it had been verified with their supervisor.

On October 19, 1990 the Station ALARA Coordinator questioned the reported radioactive contamination levels inside the opened valve and investigated the possibility of work being performed on the wrong valve. This was confirmed to be the case.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. An Out-of-Service was hung for the valve; this included closing the downstream manual valve (2-220-57A) to provide better isolation. Appropriate radiation protection measures were taken, including completing the proper Radiation Work Permit procedures. As the 2-220-62A valve was also scheduled for overhaul due to LLRT results, work was allowed to continue under the proper work package.

2. A tailgate discussing this event was presented on December 20, 1990, emphasizing the need for self-verification and that each nuclear worker has the responsibility to assure the equipment to be worked on is the equipment identified in the work package and that actions to be taken are correct.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. A more positive identification of the 2-220-62A, 62B, and 59 valves for the Unit 2 steam pipe tunnel has been provided. Additional valve identification has been applied to the support structure located over the 62A and 62B valves.

2. A tailgate article will be developed by January 31, 1991 to inform plant personnel that identification tags are expected to be attached on all plant components. If equipment tags are not found, the labeling coordinator should be notified to assure components are properly tagged and operating personnel should be contacted to assist in proper component identification before starting work.

3. This event will be incorporated into continuing training for Maintenance, Operations, Radiation Protection, and Technical Staff personnel by December 31, 1991. Emphasis will be placed on the potential significance of opening the wrong primary system boundary, opportunities by the working group and others which were available to identify that the wrong equipment was being worked on, and methods by which the correct component could have been identified (outage walkdown, pipe/penetration labeling, RWP survey maps).

4. Radiation Protection Survey Maps will be upgraded as necessary to provide for identification of equipment specified on the maps. This will be completed prior to the next scheduled refuel outages for each unit.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on October 19, 1990 when the 62A valve was properly removed from service.

EXAMPLE e

DAP 15-6, "Preparation and Control of Work Requests," Revision 0, requirements were violated on August 8, 1990, when prescribed for calibration of Unit 3 Torus to Reactor Building Vacuum Breaker A Pressure Transmitter DTP-1622A was performed instead on Pressure Transmitter DPT-1622B. This resulted in advertent opening of the Unit 3 Reactor Building Vacuum Breaker B. (50-237/90023-02e (DRP))

DISCUSSION

On August 8, 1990 the Instrument Maintenance Department (IMD) was performing a calibration check on DPT 1622A [Torus to Reactor Building Vacuum Breaker (AOV 3-1601-20A) Pressure Transmitter] using procedure DIS 1600-20, "Torus to Reactor Building Differential Pressure Transmitter 1622A and B Calibration and Maintenance Inspection."

The Instrument Mechanic (IM) valved-out the DPT1622A transmitter and connected the calibration instruments to obtain a set of as found readings. The as found readings were outside the ideal calibration tolerance range on the conservative side.

For the IM to adjust the calibration setting for DPT 1622A or 1622B he has to get down, turn 180°, arch his head and back under the transmitter. While being upside down, the IM proceeded to adjust what he thought to be DPT 1622A for AOV 3-1601-20A to bring the calibration within specified instrument tolerance range. While he was making the adjustment, the AOV 3-1601-20B opened with a resultant Control Room Annunciator. The IM had adjusted DPT 1622B instead of DPT 1622A.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. The Master Instrument Mechanic counselled the IM involved in this event. Emphasis was placed on total job awareness needing to be maintained at all times a job is in progress. Also emphasis was placed on heightened awareness while working in congested areas of the plant since the possibility of poor job performance is enhanced.

2. The Master Instrument Mechanic discussed this event at a department tailgate meeting. The discussion included a review of the situations on this job and a reminder of what is expected of Instrument Maintenance Department personnel when working in congested areas.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. The labeling of the ΔP transmitters on both units (DPT 1622A and 1622B) will be improved by placing a label above the transmitter and removing any labels below the transmitters.

2. The ΔP transmitters (DPT 1622A and 1622B) will be rotated 180 degrees to relocate the adjustment screws on the top of the transmitter (Work Requests D95106, D95107, D95108, and D95109) by June 1, 1991 (during next refueling outage) for Unit 3 and by October 1, 1991 for Unit 2. This will greatly enhance access to the adjusting screws and minimize the possibility of adjusting the wrong transmitters.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on August 8, 1990 when the Vacuum Breaker was reclosed.

VIOLATION 3

10 CFR 50, Appendix B, Criterion XVI, as implemented by Commonwealth Edison's "Quality Assurance Program," requires that conditions adverse to quality be promptly identified and corrected and, in the case of significant conditions, the measures assure the cause is determined and corrective action taken to prevent repetition.

Contrary to the above, following the fuel bundle mispositioning events of January 10 and 12, 1989, corrective actions were insufficient to prevent repetition in that similar events occurred on October 1, 1990 and October 2, 1990. (50-237/90023-08 (DRP))

This in a Severity Level IV violation (Supplement I).

DISCUSSION

On October 1, 1990, Unit 2 was in the Refuel Mode. Fuel Handlers were unloading fuel from the reactor. The grapple's Core Position Indication System was improperly indicating position in the east-west direction. The current fuel move was the last fuel move from the perimeter of the core. The next fuel move was to be from the interior of the core where no fuel assemblies had yet been removed. The Fuel Handling Supervisor went onto the Refueling Grapple to caution the fuel handling crew that the next transfer was from a different region of the core. After the current step, the duties of the Independent Verifier and the Grapple Operator were scheduled to be exchanged between the two men.

The Grapple Operator grappled the wrong fuel assembly. As the Independent Verifier had been cautioned about the next fuel move, he was studying a core map to determine the location of the next step's fuel transfer rather than independently verifying what the Grapple Operator was doing on the current step. The fuel assembly was erroneously transferred, the Grapple Operator and Independent Verifier exchanged duties, and the "new" Grapple Operator began to perform the next step. While examining the core, the fuel handling crew discovered that the previous fuel move had been performed in error.

At this time fuel moves were suspended while discussions between the Operating Engineer, Shift Engineer and Fuel Handlers took place. Prior to resumption of unloading the core, it was decided that verbal concurrence would be required from the verifier that the proper step was being initiated, prior to removing a fuel bundle from the core. A further review of the event was conducted the next morning.

On October 2, 1990, an Electrical Maintenance Supervisor (EMS) was on the Fuel Grapple to observe the operation of the Core Position Indication System in preparation for repairs scheduled for later in the day. These repairs were to be completed in response to a corrective action from the first unloading error. The Independent Verifier was discussing its operation with the EMS. The Grapple Operator positioned the grapple over the wrong fuel assembly. The Independent Verifier (while engaged in a conversation with the EMS) gave a cursory inspection of the grapple location and latched condition. He then gave the Grapple Operator verbal permission to move the fuel assembly. The fuel assembly was transferred from the core. As the Grapple Operator approached the core location of the next fuel move, he recognized that the previous step was made in error.

These events were similar to the fuel handling errors which occurred during D2R11 on January 10 and 12, 1989. Those errors were also caused by inattention to detail on the part of the Grapple Operator, lack of an effective independent verification program, and poor communications between the Grapple Operator and the Independent Verifier. A memorandum had been issued by the Assistant Superintendent of Operations on January 13, 1989 clarifying the responsibilities of the Independent Verifier. The clarification only included verifying that the correct assembly was latched. This clarification was later incorporated into applicable procedures.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. A discussion was held between members of the Fuel Handling Department (management and bargaining unit), Operations Management and Regulatory Assurance to determine the steps necessary to implement an effective independent verification program. As a result of these discussions, a Temporary Procedure Change (TPC) was made to DFP 800-1, "Unit 2 (3) Master Refueling Procedure," on October 2, 1990, delineating the steps which the Independent Verifier must follow to assure that the correct fuel assembly is being grappled.

2. A meeting was held between the Station Manager, other station management, and members of the fuel handling department on the importance of attention to detail, the importance of proper independent verification, and the importance of good communications on October 2, 1990.

3. A TPC to DAP 7-7, Revision 1, "Conduct of Refueling Operations," was made restricting access of non-fuel handling personnel on the refuel grapple while fuel was being moved.

4. The Core Position Indication System was repaired on October 2, 1990 and the rest of the core was unloaded and later reloaded without error.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. Fuel handling procedures will be revised before the next refueling outage (currently scheduled to begin on March 31, 1991) to delineate the steps which the Independent Verifier must follow to assure the correct fuel assembly is being grappled.

2. Applicable procedures will be revised to establish compensatory actions to be taken during fuel moves to and from the reactor with the Core Position Indication System out-of-service before the next refueling outage.

3. Applicable procedures will be revised to restrict the movement of fuel with non-fuel handling department personnel on the grapple before the next refueling outage.

4. A requirement will be established for fuel handlers to demonstrate the elements of the established independent verification program before (or at the beginning) of each refueling outage. Good communication techniques will also be included in the demonstration. This program will be established before the next refueling outage.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on October 2, 1990 when further effective management controls were established to control activities on the refuel floor and to define responsibilities of the Independent Verifier.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

FEB 6 1991

Docket No. 50-237
Docket No. 50-249

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Opus West III
1400 Opus Place
Downers Grove, IL 60515

Gentlemen:

Thank you for your response dated January 7, 1991, to the December 7, 1990 Notice of Violation (NOV) issued with NRC Inspection Report 50-237/90023; 50-249/90023 for the Dresden Station. We have reviewed your written comments objecting to a portion of Item 2.c of the NOV. Our response addresses each of the specific comments contained in your letter.

As indicated in your response, one of the criteria requiring a valve to be locked per Dresden Administrative Procedure (DAP) 7-14, "Control and Criteria for Locked Equipment and Valves" includes "manual valves which provide a controlled path to the Environs, including primary and secondary containment isolation valves." Your assertion that the drywell air sample system is a closed loop system is correct; however, the portion of the system downstream of the isolation valves is non-safety related and, therefore, cannot be credited as preventing a path to the environment. This portion of the system is not subjected to periodic integrated leak rate test pressure and cannot be considered a primary containment boundary. No evidence was provided to support your assumption that NRC approval of the isolation design of this system was based solely upon this being a closed loop system. We believe an additional basis was a cost/benefit decision regarding the feasibility of backfitting automatic isolation provisions. NRC approval does not alter the fact that a path to the environment still exists nor does it preclude application of other requirements.

Your contention that the NRC had reviewed leaving these valves unlocked could not be verified. Although the NRC did approve the containment isolation design provisions of this system, your February 25, 1980 submittal and subsequent NRC Safety Evaluation Report (SER) dated March 5, 1980 did not include valve locking requirements. With regard to Table I and its application to Table II in the SER dated September 24, 1982, this SER and your response letter dated November 18, 1982 indicated that during the August 1982 site visit, you had agreed to review all containment penetrations and not limit the scope to Table II. No evidence was provided to indicate that all valves listed in Table I were explicitly reviewed by the NRC for inclusion in Table II.

The NRC's position delineated in Section V of the September 24, 1982 SER was that, unless it can be demonstrated acceptable on some other defined basis, isolation valves should be either automatic or locked closed. A case in point indicating an unacceptable basis would be your request described in this same SER for exemption from Appendix J leak detection requirements for specific Reactor Building Closed Cooling Water System containment isolation valves. The NRC rejected your justification that the closed loop nature of the system insures its integrity in the event of a single active failure.

Our conclusion stands as documented in the above inspection report that the failure to lock these valves closed was contrary to your own procedure and the requirements of 10 CFR 50, Appendix B, Criterion V as well as the SEP commitment. As your response indicated that you plan to provide a means to lock closed these valves, we have no other concerns in this area at this time.

Sincerely,

HJMiller

Hubert J. Miller, Director
Division of Reactor Projects

cc w/enclosure:
D. Galle, Vice President - BWR Operations
T. Kovach, Nuclear Licensing Manager
E. D. Eenigenburg, Station Manager
DCD/DCB (RIDS)
OC/LFDCB
Resident Inspectors LaSalle, Dresden, Quad Cities
Richard Hubbard
J. W. McCaffrey, Chief, Public Utilities Division
Robert Newmann, Office of Public Counsel, State of Illinois Center
B. Siegel, LPM, NRR

Commonwealth Edison
1400 Opus Place
Downers Grove, Illinois 60515

January 7, 1991

Mr. A. Bert Davis
Regional Administrator - RIII
U.S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, Il 60137

Subject: Dresden Nuclear Power Station Units 2 and 3
Response To Notice of Violation Contained in
Inspection Report 50-237/90023; 50-249/90023
NRC Docket Nos. 50-237 and 50-249

Reference: W. D. Shafer letter to Cordell Reed dated
November 28, 1990 transmitting NRC Inspection
Report 50-237/90023; 50-249/90023

Dear Mr. Davis:

This letter provides the Commonwealth Edison Company (CECo) response (attached) to the subject three Level IV violations transmitted by the referenced NRC Inspection Report for Dresden Station. The three violations identified were: 1) inadequate training to assure satisfactory knowledge of plant administrative requirements, 2) the failure to follow procedures and instructions and 3) inadequate corrective actions with regard to fuel bundle mispositioning events. CECo has reviewed the Notice of Violations and in all but one example agrees that the violations occurred as described. The corrective actions detailed in the response will bring the Station into compliance and will prevent similar violations from occurring.

CECo recognized a negative trend in human performance, personnel-related events and views this as a serious matter. Actions were taken to address each event, but we also have taken additional timely, broad, comprehensive actions to address the identified negative trend. These actions are beyond those in the detailed responses to the Notice of Violation and are listed in Attachment A.

If your staff has any questions or comments concerning this letter, please refer them to Rita Radtke, Compliance Engineer at 708/515-7284.

Very truly yours,

T. J. Kovach
Nuclear Licensing Manager

cc: B.L. Siegel, Project Manager, NRR
D. E. Hills, Senior Resident Inspector
NRR Document Control Desk

JAN 8 1991

Attachment

/scl:ID707:1

ATTACHMENT A

Additional actions taken to address human performance, personnel-related events:

- A meeting was held with all supervisors (CECo & Contractor) on October 17, 1990 to raise overall onsite awareness. Each Supervisor was required to take notes during the meeting, meet with those employees he supervises and return his notes with names of those he met with by October 18, 1990.
- A station "Self Check" initiative, called VerAntSO, was introduced the week of October 22, 1990. VerAntSO is an acronym used to remind everyone of the self-check concept and stands for Verify, Anticipate, Stop and Observe.
- An INPO assist visit to review Human Performance activities was requested and performed on October 25 and 26, 1990.
- The CECo Performance Assessment Department performed an overview of outage concerns during the week of October 22, 1990.
- A licensed individual from Nuclear Quality Programs Department from another CECo station performed an overall review of in-plant activities during the week of October 22, 1990.
- An in-plant walkdown and independent verification of one hundred (100) out-of-services was performed to verify proper isolation of equipment for maintenance activities.

RESPONSE TO

NOTICE OF VIOLATION

VIOLATION 1

10 CFR 50, Appendix B, Criterion II, as implemented by Commonwealth Edison's "Quality Assurance Program" requires indoctrination and training of personnel performing activities affecting quality as necessary to assure that suitable proficiency is achieved and maintained.

Contrary to the above, indoctrination and training of personnel performing activities affecting quality was inadequate in assuring proficiency was achieved and maintained as to administrative requirements as indicated in the following examples:

a. Lack of operations personnel knowledge of Dresden Administrative Procedure (DAP) 7-5, "Operating Logs and Records," Revision 8, and Dresden Operating Abnormal (DOA) Procedure 902-5 G-2, Revision 3, requirements for maintaining the Control Rod Drive Accumulator High Water/Low Pressure Alarm Log (AHWLPAL) resulted in the AHWLPALs for both units not being maintained between April 1990 and August 3, 1990. As such the licensee's program to identify repeat failures of accumulator alarms was not effective during that time period (50-237/90023-01a (DRP)).

b. Lack of technical staff personnel knowledge regarding recognizing and processing conditions adverse to quality resulted in a failure to properly identify a procedural nonadherence involving maintenance of the AWHLPAL when discovered in May 1990. Because of this, corrective actions to prevent recurrence were not taken at that time. (50-237/90023-01b (DRP)).

This is a Severity Level IV violation (Supplement I).

DISCUSSION

On December 8, 1989, DAP 7-5, Revision 8 was approved. This procedure established an Accumulator High Water/Low Pressure Alarm Log (AHWLPAL). On the same day, a revision to the Unit 2(3) Operators Daily Surveillance Log (Appendix A) was approved which removed the weekly Control Rod Drive Accumulator Log from Appendix A so that there would not be two procedures recording the same information. The intent of the AHWLPAL was to maintain an ongoing record of Control Rod Drive Accumulator Alarms in order to identify problem accumulators. Either the AHWLPAL or the Control Rod Drive Accumulator Log (removed from Appendix A) would have been adequate for documenting Control Rod Drive Accumulator High Water/Low Pressure Accumulator Alarms. An AHWLPAL Book was established at each Unit Operator's Desk.

The on-shift licensed personnel did not receive formal instruction or notification as to the maintenance of the AHWLPAL during the day-to-day operation of the plant. Therefore, the implementation of the AHWLPAL was only partly accomplished by revising the procedures. The on-shift licensed personnel, responsible for maintaining the AHWPAL, did not receive training on this program.

The Technical Staff System Engineer learned in early May 1990 that the AHWLPAL was not being properly maintained as required by DAP 7-5 and realized that either the operators would have to be trained on the use of the log or that the program would have to be revised. During this same time period, the Operations Department was implementing a program to independently verify accumulator valving operations. This requirement was to be implemented by having the independent verifier sign the AHWLPAL log book. To resolve these two unrelated concerns in a coordinated manner, it was decided to place the AHWLPAL back into Appendix A. This revision to DAP 7-5 took longer than expected because of other changes to the procedure that were not related to the AHWLPAL. It took three months to resolve all of the issues with DAP 7-5. On August 30, 1990, the requirements for the AHWLPAL were transferred from DAP 7-5 back to the Unit Operator's Daily Surveillance Log, Appendix A, at which time CRD accumulator logging was resumed.

Action to correct the problem was taken, but it was not documented through the use of DAP 9-12, "Procedural Adherence Deficiencies." The System Engineer was not aware that DAP 9-12 should have been used as the mechanism to document this need for corrective action.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

The logging of accumulator alarms was transfered back to Appendix A on August 30, 1990. Since that date all accumulator alarms have been logged.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. The Operations Department, with assistance from the Training Department and the Technical Staff, will develop a method to ensure that when procedural changes are made that alter the day-to-day routine of licensed operators, a review is made to determine what training should be completed to properly implement the change. This methodology will be in-place by March 31, 1991.

2. DAP 9-12 will be tailgated to all station personnel by February 7, 1991. Emphasis will be directed to its purpose and use.

3. A number of events, occurring during the past six months, have indicated that the knowledge level of station personnel with regard to the contents of various Dresden Administrative Procedures is less than desired. To raise the station personnel knowledge level of the contents of the Dresden Administration Procedures, the Station's ongoing training program will be reviewed to verify that all personnel involved in activities addressed in each administrative program/procedure are appropriately trained. A matrix of Dresden Administrative training requirements will be produced by January 31, 1991 and appropriate changes will be made to the ongoing programs by June 30, 1991.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on August 30, 1990 at which date all accumulator alarms were properly logged.

VIOLATION 2

10 CFR 50, Appendix B, Criterion V, as implemented by Commonwealth Edison Company's Quality Assurance Program, requires that activities affecting quality be accomplished in accordance with documented instructions, procedures or drawings.

Contrary to the above, activities affecting quality were not accomplished in accordance with documented instructions, procedures, or drawings in the following examples:

This in a Severity Level IV violation (Supplement I).

EXAMPLE a

Dresden Operating Procedure (DOP) 1900-3, "Reactor Cavity-Dryer Separator Storage Pit Fill and Operation of the Fuel Pool Cooling and Cleanup System During Refueling," Revision 8, requires constant communication between the refueling floor and the control room while filling the reactor vessel. Constant communication between the refueling floor and the control room was not maintained while filling the Unit 2 reactor vessel on October 14, 1990, resulting in the overfilling of the vessel into the ventilation ducts and contamination of various areas of the third and fourth floors of the reactor building. (50-237/90023-2a (DRP))

DISCUSSION

On October 13, 1990 the reactor cavity flooding evolution began. Prior to beginning the evolution, a Fuel Handling Supervisor had agreed to monitor reactor cavity level from the refueling floor. As cavity flooding progressed, the Fuel Handling Supervisor reported on the cavity level. At 0330 hours on October 14, 1990, the Fuel Handling Supervisor informed Operations that he was leaving and that the level was approximately 1 1/2 feet below the bottom of the ventilation openings. From this point on, the reactor cavity water level was no longer being continuously observed. Later, the Unit 2 NSO dispatched the Equipment Attendant (EA) to visually observe the cavity level. The EA erroneously reported that the level was 16 inches below the bottom of the ventilation openings.

A short time later, the control room received annunciator, "Fuel Pool High Level." The NSO immediately closed the Feedwater Low Flow Valve and dispatched another EA to reject water from the fuel pool cooling system to the Condensate Storage Tank. A Shift Supervisor then proceeded to the fourth floor of the Reactor Building where he saw water coming from the ventilation ducts.

DOP 1900-3 contains a precaution: "Maintain constant communications between the refueling floor and the Control Room while filling the reactor head cavity and the dryer/separator pit to prevent overflow into the ventilation ducting." This was not followed from the time the Fuel Handling Supervisor left the refueling floor until the alarm was received in the control room.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. This event was included in a series of meetings conducted on October 17, 1990 by the Station Manager and attended by all line supervisors of CECo and Contractor organizations on site. The purpose of the meetings was to increase everyone's awareness of several recent events involving personnel error and to require subsequent meetings between these supervisors and all employees to raise the overall on-site awareness level of the need for increased attention to detail.

2. A posted operator aid was revised showing the level of the bottom of the ventilation openings to be 469 inches instead of the previously erroneous value of 476 inches.

3. Operations personnel involved in this event were counselled on the importance of procedure adherence.

4. Procedural adherence was addressed in a Shift Engineer's meeting held on October 24, 1990. Shift Engineers were instructed that procedures must be consulted and adhered to for all complex, unique, or infrequent evolutions.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. DOP 1900-3 will be revised to clarify when continuous visual monitoring is required when flooding the refuel cavity. The requirement for visual monitoring will be specified so that continuous monitoring will not be required for slow moving evolutions when level is more than three feet from the final desired level. The procedure will be revised by March 31, 1991.

2. The Instrument Maintenance Department will revise DIP 0260-01, Figure 1 to correctly depict the bottom of the cavity ventilation openings at 469 inches by March 31, 1991.

3. To aid visual estimates of water level, the Technical Staff will evaluate methods of providing a graduated scale in the Reactor cavity and in the Dryer/Separator pit for Units 2 and 3. An acceptable method will then be implemented by March 31, 1991.

4. This event was reviewed by licensed operators during Cycle 8 of continuing training. This was completed on December 7, 1990. It will be covered for non-licensed operators by March 1, 1991.

5. The EA involved in this event developed an article for the Station's monthly newsletter, discussing the importance of attention to detail, procedural adherence, and the concept of self-checking one's actions.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on October 14, 1990 when the reactor cavity flooding evolution was completed.

EXAMPLE b

Specific practices required by DAP 3-5, "Out of Service and Personnel Protection Cards," Revision 22, were not followed as to preparation, review, approval, documentation and independent verification in the removal and return to service of the Unit 2 diesel fuel oil day tank drain valve on October 20, 1990. This resulted in the inadvertent draining of the day tank when the drain valve was placed in the incorrect position. (50-237/90023-02b (DRP))

DISCUSSION

In preparation for the cleaning of the Unit 2 Diesel Generator Main Fuel Oil Storage Tank, the Diesel Fuel Oil Transfer Pump Suction valve was shut and the Fuel Oil Day Tank Drain valve was checked to be shut by a member of the Operations Staff on October 8 or 9, 1990. "Do Not Operate" tags supplied by the storage tank cleaning contractor were placed on the valves. No CECo Out-of-Service was written for the tank cleaning.

On October 20, 1990, between 10:30 and 11:00 am, the same member of the Operations Staff opened the Transfer Pump Suction Valve. In addition, he opened the Day Tank Drain Valve, even though he had checked that this valve was shut approximately 12 days prior. These valve manipulations were performed without the knowledge of on-shift Operations or procedural guidance.

At approximately 11:20 am on Saturday, October 20, 1990, the "Unit 2 Diesel Generator Day Tank Hi/Lo Level" alarm was received in the Control Room. At approximately the same time, two members of the Technical Staff were in the vicinity of the diesel generator room and observed a strong odor of fuel oil. Upon entering the room, they noticed fuel oil on the floor.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. A member of the Technical Staff traced the source of the fuel spill to the drain on the Unit 2 Fuel Oil Day Tank, found drain valve 2-5212-500 approximately one to two turns open and closed the valve. Approximately 600 gallons of fuel oil were spilled.

2. The involved Operations Supervisor was counseled on the need to interact with Operations Department shift personnel to ensure that all valves necessary to adequately isolate a component are included on the appropriate Out-Of-Service. The involved individual was reminded that unauthorized valve manipulation is against plant policy and could lead to personnel injury or equipment damage.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCE

1. The Day Tank drain valves on all three emergency diesels were locked shut. The Locked Valve Checklist and System Checklist will be revised to include the Day Tank Drain on all emergency diesels in the locked closed position by March 31, 1991.

2. The details of this event were reviewed with all station personnel at the October 18, 1990 tailgate meetings, emphasizing the need to properly use the Out-Of-Service program and the hazards of unauthorized equipment manipulations.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on October 20, 1990 when the drain valve was closed.

EXAMPLE c

DAP 7-14, "Control and Criteria For Locked Equipment and Valves," Revision 2, requires manual valves in the flowpath of systems required for plant shutdown during post-accident situations or which provide a controlled path to the environs, including primary and secondary containment isolation valves to be locked. Prior to November 1990, manual valves including the Units 2, 3 and 2/3 diesel generator service water three-way valves and the Units 2 and 3 drywell manifold sampling system containment isolation valves were not locked or designated to be locked (50-237/90023-02c (DRP)).

DISCUSSION

The Diesel Generator Service Water flow reversal valves were erroneously excluded from the locked valve checklist. This was due to the valves having a mechanical locking device which prevents the valves from repositioning. The Station believed that the locking device (which does not have a keyed lock) fulfilled the administrative requirements of the locked valve program.

CECo does not believe that a requirement existed to "lock closed" the 2(3)-8507-500 through 521 Drywell Air Sample Valves. The USNRC had, on two separate occasions, the opportunity to review and assess the acceptability of those valves. On each occasion they found the design to be acceptable:

1. In response to NUREG 0578, in a letter dated February 25, 1980, CECo supplied information on primary containment isolation valves. An excerpt from that letter reads as follows, "All non-essential systems that provide a possible open path out of the primary containment were found to be either isolated by isolation signals, by check valves that would prevent flow out of the containment, by manual valves that are normally closed during reactor operation, or as in the case of instrument lines by closed piping systems." Included were the 2(3)-8507-500 through 521 valves with their classification (non-essential) and a sketch showing their configuration. The USNRC, in a letter dated March 5, 1980, responded, "We conclude that the licensee has completed a re-determination of which containment isolation penetrations are essential or non-essential. All non-essential lines are either automatically isolated by diverse signals or technical justification has been provided. Modifications have been made to prevent inadvertent re-opening of isolation valves. Based on the above, we find that the licensee has satisfied the requirements of this item."

2. Various correspondence exists documenting the scope and depth of the USNRC review of SEP Topic VI-4, "Containment Isolation Systems." An NRC letter dated December 18, 1981, transmitted a draft SER on the topic and requested that CECo provide comments and additional information. CECo's response of May 21, 1982 provided information on the 2(3)-8507-500 through 521 valves. Based upon that response, the NRC issued their final SER on September 24, 1982. Table I of that SER provides a list of valves which they reviewed; the 2(3)-8507-500 through 521 valves are included on that list. A section of the SER titled, "Administrative Control," identifies valves which have inadequate administrative controls and which should be listed as "locked closed" instead of "normally closed." These valves are listed in Table II; the 2(3)-8507-500 through 521 valves are not included. Another section titled, "Manual Isolation Valves," lists other valves which should be in a "locked closed" position; once again the 2(3)-8507-500 through 521 valves are not included.

Although the basis of acceptability for these valves being "normally open" or "normally closed" is not provided in the SERs, it presumably is due to the Drywell Air Sample system being a closed loop system. In any case, the NRC reviewed these valves as part of post-TMI and SEP, and did not require them to be "locked closed."

The Inspection Report and Notice of Violation reference a November 18, 1982 commitment to "review all containment penetrations in the plant and not limit the scope to Table II in the SER." DAP 7-14, "Control and Criteria for Locked Equipment and Valves," is also referenced. One of the DAP 7-14 criteria for locked valves is, "Manual valves which provide a controlled path to the Environs, including Primary and Secondary Containment isolation valves." Since the Drywell Air Sample system is a closed loop system, leakage past these valves would not provide an uncontrolled path to the environs. CECo does not believe that operation of a system consistent with the plant's original design basis and in accordance with NRC SERs and Station administrative programs constitutes a violation of NRC requirements.

During a recent investigation into the use of a temporary sample pump to obtain drywell air samples (in which the Drywell Air Sample system's closed loop was broken), questions arose relative to the ability of the original Drywell Air Sample system to withstand seismic and accident conditions. In view of this recent information, CECo is re-assessing the acceptability the system. Past performance of the system has shown only limited usefulness in its ability to locate sources of leakage into the drywell. With the recent approval of the Station's Generic Letter 88-01 submittal (in which no credit was taken for the Drywell Air Sample system) it is believed that the system may be removed. Final resolution of the Drywell Air Sample system is expected in February, 1991. As an interim measure, valves 2(3)-8507-500 through 521 have been taken out-of-service closed. These valves will remain controlled by the out-of-service or locked closed in accordance with DAP 7-14 as long as the system remains in place. Since no method of locking these valves presently exists, work requests have been written to provide a means of locking them. The valves will be added to the locked valve checklist and locked as appropriate prior to clearing the out-of-service on these valves.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

Temporary Procedure Change 90-408 was written against Dresden Operating Procedure (DOP) 040-M3, "Locked Valve List: Accessible During Operations," adding the Diesel Generator Service Water flow reversal valves to the Locked Valve List. The valves were also locked at that time.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. DOP 040-M3 will be revised by March 31, 1991 to include the Diesel Generator Service Water three-way valves.

2. A review of other valves with mechanical locking devices will be conducted to assure that they are not being inappropriately excluded from the locked valve program by March 31, 1991.

3. DAP 7-14 criteria will be reviewed and revised as necessary to assure the locked valve criteria are easily understood by station personnel. This will be accomplished by March 31, 1991.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on November 27, 1990 when the valves were locked into position.

EXAMPLE d

DAP 15-6, "Preparation and Control of Work Requests," Revision 0, requires work to be performed per repair manual(s), travelers/procedures, or work instructions provided in the work package. On October 15, 1990, work prescribed for disassembly of the Outboard Containment Isolation Feedwater Check Valve 220-62B was performed instead on Outboard Containment Isolation Feedwater Check Valve 220-62A (50-237/90023-02d (DRP)).

DISCUSSION

As a result of local leak rate tests (LLRTs) performed on September 24 and 30, 1990 on the 2-220-62A and 62B check valves, the decision was made to repair the valves. A maintenance pre-job briefing and ALARA pre-job briefing were performed on October 12, 1990 prior to proceeding to the work area for disassembly of the 62B check valve. The Maintenance Supervisor accompanied his crew to the work location and directed them to begin work on what he believed to be the 62B valve, but was actually the 62A valve.

Upon removal of the valve bonnet and seal ring, the valve body was found full of water and the valve disc stuck in the open position. All work was immediately stopped, the Maintenance Supervisor and Technical Staff were notified of the as found condition. Water was pumped from the valve body and work continued on valve decontamination, inspection and repair.

On October 17, 1990 a Radiation Protection Technician (RPT) surveyed the valve plug and seat. The RPT was concerned that work was being performed on the wrong valve and questioned the crew several times whether they were working on the correct valve. The crew indicated that they were sure they were on the correct valve and that it had been verified with their supervisor.

On October 19, 1990 the Station ALARA Coordinator questioned the reported radioactive contamination levels inside the opened valve and investigated the possibility of work being performed on the wrong valve. This was confirmed to be the case.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. An Out-of-Service was hung for the valve; this included closing the downstream manual valve (2-220-57A) to provide better isolation. Appropriate radiation protection measures were taken, including completing the proper Radiation Work Permit procedures. As the 2-220-62A valve was also scheduled for overhaul due to LLRT results, work was allowed to continue under the proper work package.

2. A tailgate discussing this event was presented on December 20, 1990, emphasizing the need for self-verification and that each nuclear worker has the responsibility to assure the equipment to be worked on is the equipment identified in the work package and that actions to be taken are correct.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. A more positive identification of the 2-220-62A, 62B, and 59 valves for the Unit 2 steam pipe tunnel has been provided. Additional valve identification has been applied to the support structure located over the 62A and 62B valves.

2. A tailgate article will be developed by January 31, 1991 to inform plant personnel that identification tags are expected to be attached on all plant components. If equipment tags are not found, the labeling coordinator should be notified to assure components are properly tagged and operating personnel should be contacted to assist in proper component identification before starting work.

3. This event will be incorporated into continuing training for Maintenance, Operations, Radiation Protection, and Technical Staff personnel by December 31, 1991. Emphasis will be placed on the potential significance of opening the wrong primary system boundary, opportunities by the working group and others which were available to identify that the wrong equipment was being worked on, and methods by which the correct component could have been identified (outage walkdown, pipe/penetration labeling, RWP survey maps).

4. Radiation Protection Survey Maps will be upgraded as necessary to provide for identification of equipment specified on the maps. This will be completed prior to the next scheduled refuel outages for each unit.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on October 19, 1990 when the 62A valve was properly removed from service.

EXAMPLE e

DAP 15-6, "Preparation and Control of Work Requests," Revision 0, requirements were violated on August 8, 1990, when prescribed for calibration of Unit 3 Torus to Reactor Building Vacuum Breaker A Pressure Transmitter DTP-1622A was performed instead on Pressure Transmitter DPT-1622B. This resulted in advertent opening of the Unit 3 Reactor Building Vacuum Breaker B. (50-237/90023-02e (DRP))

DISCUSSION

On August 8, 1990 the Instrument Maintenance Department (IMD) was performing a calibration check on DPT 1622A [Torus to Reactor Building Vacuum Breaker (AOV 3-1601-20A) Pressure Transmitter] using procedure DIS 1600-20, "Torus to Reactor Building Differential Pressure Transmitter 1622A and B Calibration and Maintenance Inspection."

The Instrument Mechanic (IM) valved-out the DPT1622A transmitter and connected the calibration instruments to obtain a set of as found readings. The as found readings were outside the ideal calibration tolerance range on the conservative side.

For the IM to adjust the calibration setting for DPT 1622A or 1622B he has to get down, turn 180°, arch his head and back under the transmitter. While being upside down, the IM proceeded to adjust what he thought to be DPT 1622A for AOV 3-1601-20A to bring the calibration within specified instrument tolerance range. While he was making the adjustment, the AOV 3-1601-20B opened with a resultant Control Room Annunciator. The IM had adjusted DPT 1622B instead of DPT 1622A.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. The Master Instrument Mechanic counselled the IM involved in this event. Emphasis was placed on total job awareness needing to be maintained at all times a job is in progress. Also emphasis was placed on heightened awareness while working in congested areas of the plant since the possibility of poor job performance is enhanced.

2. The Master Instrument Mechanic discussed this event at a department tailgate meeting. The discussion included a review of the situations on this job and a reminder of what is expected of Instrument Maintenance Department personnel when working in congested areas.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. The labeling of the ΔP transmitters on both units (DPT 1622A and 1622B) will be improved by placing a label above the transmitter and removing any labels below the transmitters.

2. The ΔP transmitters (DPT 1622A and 1622B) will be rotated 180 degrees to relocate the adjustment screws on the top of the transmitter (Work Requests D95106, D95107, D95108, and D95109) by June 1, 1991 (during next refueling outage) for Unit 3 and by October 1, 1991 for Unit 2. This will greatly enhance access to the adjusting screws and minimize the possibility of adjusting the wrong transmitters.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on August 8, 1990 when the Vacuum Breaker was reclosed.

VIOLATION 3

10 CFR 50, Appendix B, Criterion XVI, as implemented by Commonwealth Edison's "Quality Assurance Program," requires that conditions adverse to quality be promptly identified and corrected and, in the case of significant conditions, the measures assure the cause is determined and corrective action taken to prevent repetition.

Contrary to the above, following the fuel bundle mispositioning events of January 10 and 12, 1989, corrective actions were insufficient to prevent repetition in that similar events occurred on October 1, 1990 and October 2, 1990. (50-237/90023-08 (DRP))

This in a Severity Level IV violation (Supplement I).

DISCUSSION

On October 1, 1990, Unit 2 was in the Refuel Mode. Fuel Handlers were unloading fuel from the reactor. The grapple's Core Position Indication System was improperly indicating position in the east-west direction. The current fuel move was the last fuel move from the perimeter of the core. The next fuel move was to be from the interior of the core where no fuel assemblies had yet been removed. The Fuel Handling Supervisor went onto the Refueling Grapple to caution the fuel handling crew that the next transfer was from a different region of the core. After the current step, the duties of the Independent Verifier and the Grapple Operator were scheduled to be exchanged between the two men.

The Grapple Operator grappled the wrong fuel assembly. As the Independent Verifier had been cautioned about the next fuel move, he was studying a core map to determine the location of the next step's fuel transfer rather than independently verifying what the Grapple Operator was doing on the current step. The fuel assembly was erroneously transferred, the Grapple Operator and Independent Verifier exchanged duties, and the "new" Grapple Operator began to perform the next step. While examining the core, the fuel handling crew discovered that the previous fuel move had been performed in error.

At this time fuel moves were suspended while discussions between the Operating Engineer, Shift Engineer and Fuel Handlers took place. Prior to resumption of unloading the core, it was decided that verbal concurrence would be required from the verifier that the proper step was being initiated, prior to removing a fuel bundle from the core. A further review of the event was conducted the next morning.

On October 2, 1990, an Electrical Maintenance Supervisor (EMS) was on the Fuel Grapple to observe the operation of the Core Position Indication System in preparation for repairs scheduled for later in the day. These repairs were to be completed in response to a corrective action from the first unloading error. The Independent Verifier was discussing its operation with the EMS. The Grapple Operator positioned the grapple over the wrong fuel assembly. The Independent Verifier (while engaged in a conversation with the EMS) gave a cursory inspection of the grapple location and latched condition. He then gave the Grapple Operator verbal permission to move the fuel assembly. The fuel assembly was transferred from the core. As the Grapple Operator approached the core location of the next fuel move, he recognized that the previous step was made in error.

These events were similar to the fuel handling errors which occurred during D2R11 on January 10 and 12, 1989. Those errors were also caused by inattention to detail on the part of the Grapple Operator, lack of an effective independent verification program, and poor communications between the Grapple Operator and the Independent Verifier. A memorandum had been issued by the Assistant Superintendent of Operations on January 13, 1989 clarifying the responsibilities of the Independent Verifier. The clarification only included verifying that the <u>correct</u> assembly was latched. This clarification was later incorporated into applicable procedures.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. A discussion was held between members of the Fuel Handling Department (management and bargaining unit), Operations Management and Regulatory Assurance to determine the steps necessary to implement an effective independent verification program. As a result of these discussions, a Temporary Procedure Change (TPC) was made to DFP 800-1, "Unit 2 (3) Master Refueling Procedure," on October 2, 1990, delineating the steps which the Independent Verifier must follow to assure that the correct fuel assembly is being grappled.

2. A meeting was held between the Station Manager, other station management, and members of the fuel handling department on the importance of attention to detail, the importance of proper independent verification, and the importance of good communications on October 2, 1990.

3. A TPC to DAP 7-7, Revision 1, "Conduct of Refueling Operations," was made restricting access of non-fuel handling personnel on the refuel grapple while fuel was being moved.

4. The Core Position Indication System was repaired on October 2, 1990 and the rest of the core was unloaded and later reloaded without error.

CORRECTIVE ACTIONS TO PREVENT FURTHER NONCOMPLIANCES

1. Fuel handling procedures will be revised before the next refueling outage (currently scheduled to begin on March 31, 1991) to delineate the steps which the Independent Verifier must follow to assure the correct fuel assembly is being grappled.

2. Applicable procedures will be revised to establish compensatory actions to be taken during fuel moves to and from the reactor with the Core Position Indication System out-of-service before the next refueling outage.

3. Applicable procedures will be revised to restrict the movement of fuel with non-fuel handling department personnel on the grapple before the next refueling outage.

4. A requirement will be established for fuel handlers to demonstrate the elements of the established independent verification program before (or at the beginning) of each refueling outage. Good communication techniques will also be included in the demonstration. This program will be established before the next refueling outage.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on October 2, 1990 when further effective management controls were established to control activities on the refuel floor and to define responsibilities of the Independent Verifier.

TAB 16

DRESDEN 2 & 3

FIRE PROTECTION PROGRAM DOCUMENTATION PACKAGE

Inspection Report No. 50-237/90023 and 50-249/90023

INSPECTION REPORT SUMMARY
50-237/90027; 50-249/90026

Inspectors:	D. Hills, M. Peck, J. Monninger, J. Holmes
Inspection Scope:	Routine, unannounced safety inspection
Inspection Period:	November 17 through December 29, 1990

Violations	Non-Cited Violations	Unresolved Items	Open Items
2	5	6	1

Violations: One level IV violation was identified for failure to follow procedure in regard to maintenance practices on 10 CFR 50 Appendix R emergency lighting batteries. No reply to this violation is required because actions had been taken to correct the identified violation and to prevent recurrence (p. 1, 6-7).

The second violation, also a level IV, was for failure to report to the NRC an Engineered Safety Feature (ESF) actuation in accordance with 10 CFR 50.72 (p. 1, 13-14). This violation does require a reply.

Noncited Violations: The following are five violations for which Notices of Violation are not being issued:

- failure to adequately control the use of under vessel platform covers such that a source range monitor was subsequently damaged during movement (p. 2, 5-6).
- failure of a Quality Control inspector to follow radiation protection administrative procedures resulted in contamination of the inspector (p. 2, 9).
- failure to follow a procedure during a main steamline plug installation resulted in a small portion of clean, demineralized water drained to the drywell (p. 2, 16-17).
- failure to maintain records, which include a written safety evaluation, for the standby gas treatment system (p. 2, 20-21).
- failure to post a proposed imposition of a civil penalty associated with the use of a temporary sample pump in the drywell mainfold sampling system (p. 2, 23-24).

Unresolved Items: The following six unresolved items were identified:

- the service air supply to three of the Unit 3 drywell purge and ventilation fan dampers had been disconnected with no temporary alteration tags attached to the air lines or the dampers' operators. This is pending review of operator involvement and safety significance (p. 2, 12).

- failure of an electrical wiring diagram to reflect the actual plant configuration which resulted in an unexpected ESF actuation (p. 2, 12-13).

- use of a temporary pump and hose assembly to augment the filtering capability of the fuel pool clean-up system during refueling is pending further review regarding safety implications and proper use of procedures and/or temporary alterations (p. 2, 15).

- failure of a primary containment integrated leak rate test (ILRT) due to a leaking torus to reactor building vacuum breaker is pending further review of the adequacy of post-maintenance testing (p. 2, 17).

- failure to obtain a technical specification change and initiate the required surveillance calibration for a modification to limit switches on the control valve fast acting solenoids (which provide the scram signal to the reactor protection system on generator load reject) is pending further review of the modification with respect to 10 CFR 50.59 requirements (p. 2, 21-22).

- concerns with respect to conformance to Generic Letter 82-12 guidelines on overtime as it is applied to all plant staff groups (p. 2, 22-23).

Open Items: Determination of the current status of remaining Systematic Evaluation Program items is considered an open item (p. 24).

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

JAN 1 7 1991

Docket No. 50-237
Docket No. 50-249

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Opus West III
1400 Opus Place
Downers Grove, IL 60515

Gentlemen:

This refers to the routine safety inspection conducted by D. Hills, M. Peck, J. Monninger and J. Holmes of this office on November 17 through December 29, 1990, of activities at Dresden Nuclear Power Station, Units 2 and 3 authorized by Operating License Nos. DPR-19 and DPR-25 and to the discussion of our findings with Mr. E. Eenigenburg and others at the conclusion of the inspection.

The enclosed copy of our inspection report identifies areas examined during the inspection. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations, and interviews with personnel.

During this inspection, certain of your activities appeared to be in violation of NRC requirements, as described in the enclosed Notice. With respect to violation A, the inspection showed that actions had been taken to correct the identified violation and to prevent recurrence. Consequently, no reply to this item is required and we have no further questions regarding this item at this time. Regarding the remaining item, a written response is required.

In addition, five violations were identified for which Notices of Violation are not being issued in accordance with the exercise of discretion delineated in either 10 CFR 2, Appendix C, Section V.A or V.G.1.

In accordance with 10 CFR 2.790, of the Commission's Regulations, a copy of this letter and the enclosure(s) will be placed in the NRC Public Document Room.

The responses directed by this letter and the accompanying Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, PL 96-511.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

W D Shafer

W. D. Shafer, Chief
Reactor Projects Branch 1

Enclosures:
1. Notice of Violation
2. Inspection Report
   No. 50-237/90027(DRP)
   No. 50-249/90026(DRP)

cc w/enclosures:
D. Galle, Vice President - BWR Operations
T. Kovach, Nuclear Licensing Manager
E. D. Eenigenburg, Station Manager
DCD/DCB (RIDS)
OC/LFDCB
Resident Inspectors LaSalle, Dresden, Quad Cities
Richard Hubbard
J. W. McCaffrey, Chief, Public Utilities Division
Robert Newmann, Office of Public Counsel, State of Illinois Center

NOTICE OF VIOLATION

Commonwealth Edison Company
Dresden Nuclear Power Station

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

During an NRC inspection conducted on November 17 through December 29, 1990, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1990), the violations are listed below:

A. Section III.J. of 10 CFR Part 50, Appendix R, requires emergency lighting units with at least an 8 hour battery power supply to be installed in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto.

   Technical Specification Section 6.2, entitled "Plant Operating Procedures," requires procedures that detail the Fire Protection Program Implementation, be prepared, approved and adhered to.

   Contrary to the above, the licensee did not adhere to Dresden Electrical Surveillance (DES) 4153-02, "Emergency Lighting Monthly Inspection," Revision 0, Section I.d.(1), in that distilled water was not added to the emergency light when the electrolyte level was identified on October 29, 1990, below the fill line as required by the procedure.

   This is a severity level IV violation (Supplement I).

B. 10 CFR 50.72(b)(2)(ii) requires the NRC to be notified within four hours of the occurrence of any event or condition that results in manual or automatic actuation of any Engineered Safety Feature (ESF).

   Contrary to the above, the unexpected closure of several Unit 2 Group II primary containment isolation valves upon lifting of an electrical lead during post-maintenance testing on December 8, 1990, constituted an automatic actuation of an ESF and the NRC was not notified of the occurrence.

   This is a severity level IV violation (Supplement I).

With respect to Item A, the inspection showed that actions had been taken to correct the identified violation and to prevent recurrence. Consequently, no reply to the violation is required and we have no further questions regarding this matter. With respect to Item B, pursuant to the provisions of 10 CFR 2.201, you are required to submit to this office within thirty days of the date of this Notice a written statement or explanation in reply, including for each violation: (1) the corrective steps that have been taken and the results achieved; (2) the corrective steps that will be taken to avoid further violations; and (3) the date when full compliance will be achieved. Consideration may be given to extending your response time for good cause shown.

1-17-91
Dated

W D Shafer
W. D. Shafer, Chief
Reactor Projects Branch 1

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/90027(DRP); 50-249/90026(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: November 17 through December 29, 1990

Inspectors: D. Hills
M. Peck
J. Monninger
J. Holmes

Approved By: B. Burgess, Chief
Projects Section 1B

1/17/91
Date

Inspection Summary

Inspection during the period of November 17 through December 29, 1990
(Report Nos. 50-237/90027(DRP); 50-249/90026(DRP))
Areas Inspected: Routine unannounced resident inspection of previously identified inspection items, licensee event reports followup, plant operations, maintenance/surveillance, engineering/technical support, safety assessment/quality verification, systematic evaluation program items and report review.
Results:
Two violations were identified for which Notices of Violation are being issued. One dealt with a failure to follow procedure in regard to maintenance practices on 10 CFR 50 Appendix R emergency lighting batteries (paragraph 2). The other involved a failure to report to the NRC an Engineered Safety Feature (ESF) actuation in accordance with 10 CFR 50.72 (paragraph 4.e).

Five violations were identified for which Notices of Violation are not being issued in accordance with the exercise of discretion delineated in 10 CFR 2, Appendix C, Section V.A or V.G.1. These involved a failure to adequately control the status of under vessel platform covers such that a source range monitor (SRM) was subsequently damaged during movement (paragraph 2), a failure to follow procedure involving radiation protection practices (paragraph 4), a failure to follow procedure regarding a main steamline plug installation such that a small portion of the reactor cavity drained to the drywell (paragraph 5.a), a failure to maintain records for a standby gas treatment system (SGTS) written safety evaluation (paragraph 5.b) and a failure to post a proposed imposition of a civil penalty (paragraph 7.c).

Six unresolved items were also identified. The inspector's identification that the service air supply to three of the Unit 3 drywell purge and ventilation fan dampers had been disconnected is pending review of system design and the role of the operators in the event (paragraph 4.c). The failure of electrical wiring diagram 12E2697 to reflect actual plant configuration which resulted in an unexpected ESF actuation is pending review of licensee corrective actions (paragraph 4.e). The inspector's identification of the licensee's usage of a temporary pump and hose assembly to augment filtering of the reactor cavity water during refueling without a procedure or temporary alteration is pending further review of safety implications and 10 CFR 50.59 aspects (paragraph 4.f). Failure of a primary containment integrated leak rate test (ILRT) due to a leaking torus to reactor building vacuum breaker is pending review of the adequacy of post-maintenance testing (paragraph 5.b). The failure to obtain a technical specification change and initiate corresponding surveillance calibration requirements for a modification to the generator load reject scram on turbine control fast closure is pending further review of 10 CFR 50.59 implications (paragraph 5.c). Inspector concerns regarding conformance to Generic Letter 82-12 guidelines on overtime is pending review of further plant staff groups (paragraph 7.b).

Plant Operations

A review of the Operations Department in regard to overtime policy indicated that instances of exceeding Generic Letter 82-12 guidelines was minimal. However, certain concerns were raised in that fuel handlers, except for the fuel handling supervisors, were not included and the level of approval for exceeding the guidelines delineated in administrative procedures did not appear consistent with Generic Letter 82-12 intent.

The inspectors noted that general housekeeping and contamination control had deteriorated during the Unit 2 refueling outage as compared to recent previous refueling outages. The licensee planned to implement a new material condition/housekeeping/safety inspection program in January 1991.

Maintenance/Surveillance

Two instances of failing to follow procedure involving maintenance personel were noted. These involved maintenance practices on 10 CFR 50 Appendix R emergency lighting batteries and main steam line plug installation. However, both actually occurred prior to licensee corrective actions to address personnel performance problems delineated in inspection report 50-237/90023; 50-249/90023.

A review of the Maintenance Department in regard to overtime policy indicated that instances of exceeding Generic Letter 82-12 guidelines was minimal.

Engineering/Technical Support

Subsequent to the Notice of Violation and Proposed Imposition of Civil Penalty dated November 28, 1990 involving a 10 CFR 50.59 violation, the inspector identified concerns which indicated additional poor past practices regarding the licensee's safety evaluation process. For example, a failure to maintain records of a written safety evaluation involving SGTS is identified as a non-cited violation. In addition, two unresolved items needed further review with regard to 10 CFR 50.59 requirements. These included a failure to obtain a technical specification change regarding a modification to the generator load reject scram function and the use of a temporary pump and hose assembly, without a safety evaluation, for the reactor cavity water filtering system.

The root causes associated with the failure to post a proposed impostion of a civil penalty were repetitive to the cause of a previous violation involving a failure to ensure personnel were properly trained on specific administrative requirements. The licensee already had plans to address this concern with a new administrative requirement training program to be implemented in the spring of 1991.

The inspectors noted that staffing of the plant Technical Staff had increased substantially. Staffing was regarded as a weakness in the last Systematic Assessment of Licensee Performance (SALP) period. The licensee did not apply the Generic Letter 82-12 guidelines on overtime to the plant Technical Staff. Instances were identified where these guidelines were exceeded, most notably during the refueling outage with the inservice testing/inservice inspection group. No problems were noted during non-refueling outage periods.

Safety Assessment/Quality Verification

The inspectors noted that the rate of events indicative of personnel performance problems decreased substantially during the second half of the Unit 2 refueling outage as a result of licensee management actions delineated in inspection report 50-237/90023; 50-249/90023.

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
M. Korchynsky, Operating Engineer
B. Zank, Operating Engineer
J. Williams, Operating Engineer
R. Stobert, Operating Engineer
M. Strait, Technical Staff Supervisor
L. Johnson, Q.C. Supervisor
J. Mayer, Station Security Administrator
D. Morey, Chemistry Services Supervisor
D. Saccomando, Health Physics Services Supervisor
K. Kociuba, Quality Assurance Superintendent
*D. Lowenstein, Regulatory Assurance Analyst
*J. Harrington, Nuclear Quality Programs Inspector
*G. Kusnik, Quality Control Inspector
*D. Booth, Master Electrician
*C. Oshier, Lead Health Physicist
*R. Whalen, Assistant Technical Staff Supervisor
*D. Gulati, Master Instrument Mechanic

The inspectors also talked with and interviewed several other licensee employees, including members of the technical and engineering staffs, reactor and auxiliary operators, shift engineers and foremen, electrical, mechanical and instrument personnel, and contract security personnel.

*Denotes those attending one or more exit interviews conducted informally at various times throughout the inspection period.

2. Previously Identified Inspection Items (92701 and 92702)

(Closed) Violation (50-237/89022-02): A penetration in a three hour fire rated wall of the reactor building was not included in design documents, and modifications were not controlled as required by the licensee's fire protection plan which was implemented in accordance with 10 CFR 50.48(a). The inspector performed visual observation and reviewed documentation to verify that appropriate corrective actions were implemented. The inspector has no other concerns in this area.

(Closed) Open Item (50-237/90009-02): The inspector visually verified that the problem related to legibility of the medium range drywell pressure strip chart recorder indicator scale had been corrected. The inspector has no other concerns in this area.

(Closed) Unresolved Item (50-237/90023-04): Concern regarding the discovery of damage to the Unit 2, SRM 22, following the suspension of core alterations on November 12, 1990. The damage resulted when the SRM was withdrawn during an instrument response check and the drive mechanism came in contact with an under vessel platform access hole cover. The contact with the access cover resulted in the SRM becoming dislodged approximately three feet below the fully inserted position. Subsequent to the damage, fourteen fuel bundles were loaded into the SRM 22 core quadrant. Technical Specification 3.10.B. required SRM 22 to be operable and fully inserted to the normal operating level in the core during core alterations in that quadrant of the reactor vessel. Review of licensee fuel handling records revealed that SRM 22 did indicate the expected neutron response during fuel movement while the instrument was in a degraded condition.

On November 6, 1990, work was completed under the Unit 2 reactor to install new SRM probe connectors per Work Request (WR) 95435. During the probe replacement, platform access hole covers were utilized to minimize the potential for personnel injury during the under vessel work. The work instructions accompanying WR 95435 did not address or control the use of the platform access covers. However, a hand written memorandum was issued to all instrument maintenance (IM) supervisors requiring that the access covers be removed prior to the withdrawal of any of the SRMs for the performance of the instrument response check. Additionally, a caution tag was placed in the control room instructing the operator not to withdraw the SRMs without first receiving permission from the IM supervisor. This same methodology was utilized without incident during the previous Unit 3 refueling outage. On November 12, 1990, operations personnel received erroneous permission from the IM supervisor prior to the withdrawal and subsequent damage to SRM 22. To prevent recurrence of this event, the licensee planned to revise the applicable procedures to control the use of platform access covers under the Out-Of-Service program.

The failure to provide adequate measures to prevent inadvertent operation of the SRM drives in relation to the status of the platform covers is considered to be a violation (50-237/90027-01(DRP)) of 10 CFR 50, Appendix B, Criterion XIV. 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. The inspector has no further concerns in this area.

(Closed) Unresolved Item (50-237/89013-02(DRS)); 50-249/89012-02(DRS)): The licensee indicated that the fire fighting foam concentrate shelf life would be verified and, if testing is required, it would be scheduled. According to the licensee action item report (Item Number 237-100-89-01302) the licensee had replaced the foam and had initiated Dresden Fire Protection Procedure (DFPP) 4114-07, "Annual Fire Fighting Foam Sampling." The inspector's review of the procedure found it to be acceptable. Based on the licensee's actions, this item is considered closed.

(Closed) Unresolved Item (50-237/88010-03(DRP); 50-249/88012-03(DRS)): The simultaneous spurious opening of the Target Rock Valve and Electromatic Relief Valves has a tremendous impact in reactor coolant inventory based on the limited capacity of the Control Rod Drive (CRD) Hydraulic System to restore or maintain reactor coolant inventory. Due to the significance of this issue and its generic implications, this issue was referred to the Office of Nuclear Reactor Regulation (NRR) for resolution. NRR Safety Evaluation forwarded by letter dated July 6, 1989, from B. Siegel, NRC, to T. Kovach, CECo, accepted the licensee's modification to install two new control cables in a separate tray to rectify the potential that existed for fire induced multiconductor cable fault in two control cables associated with Unit 3 Target Rock Valve and Electromatic Relief Valves. The licensee provided the inspector with modification close out form (Number M12-3-88-24) that indicated that the work of installing two new control cables in a separate tray was completed. This item is considered closed.

(Closed) Unresolved Item (50-237/90023-06(DRP)): The inspectors identified six Appendix "R" emergency lights with the electrolyte level below the add line. Dresden Electrical Surveillance (DES) 4153-02, "Emergency Lighting Monthly Inspection", stated that "Electrolyte level shall be at the full line". However, contrary to the established procedure, the licensee indicated that a practice had been followed such that the emergency lights need only be filled when the electrolyte level was at or below the add line. The licensee further indicated that also contrary to the established procedure, the determination to add distilled water was at the discretion of the maintenance personnel. Conversations with the emergency light vendor and review of the vendor technical manual indicated that allowing the electrolyte level to fall below the add line could cause damage to the battery.

Licensee follow-up of the October 19, 1990, inspector observations identified extremely low or empty electrolyte levels in the following emergency lights:

Emergency Light Number	Electrolyte Level
(1) 271	Empty
(2) 274	Empty
(3) 275	Empty
(4) 299A	Empty
(5) 352	Extremely Low

The licensee's response to this unresolved item dated December 14, 1990, from T. J. Kovach, (CECo), to A. B. Davis, (NRC), contained a deviation report (12-2/3-90-123) which included an event summary, root causes and corrective actions (which included replacing several emergency lights) for Units 2 and 3. Based on our review of this report and supporting documentation, it was determined that due to the number of emergency lights observed with extremely low or no electrolyte, and the lack of adherence to the emergency lighting inspection procedure that this unresolved item has been upgraded to a violation (50-237/90027-02(DRP)) of Technical Specification Section 6.2. Based on prompt and thorough action to prevent recurrence and commitments to revise the emergency lighting procedure, no response to this violation is required and the NRC has no further questions regarding this matter.

Administrative Closure of Items

NRC Region III management reviewed the existing open items for the Dresden Station and determined that the following open items will be closed administratively due to their safety significance relative to emerging priority issues and to the age of the item. The licensee is reminded that commitments directly relating to these open items are the responsibility of the licensee and should be met as committed. NRC Region III will review licensee actions by periodically sampling administratively closed items.

50-237/84027-01
50-237/85003-BB
50-237/87006-03
50-237/89022-01
50-249/85003-BB

One cited and one non-cited violation and no 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 (237/90006(DRP)): Target Rock Safety-Relief Valve Failed Open. This event and corresponding corrective actions were discussed in inspection report 50-237/90019(DRP); 50-249/90019(DRP).

(Closed) LER (237/90007(DRP)): Unplanned Primary Containment Group V Isolation. This event and corresponding corrective actions were discussed in inspection report 50-237/90019(DRP); 50-249/90019(DRP).

(Closed) LER (237/90008(DRP)): Failure of HPCI Steam Line High Flow Isolation Differential Pressure Transmitter. This event and corresponding corrective actions were discussed in inspection report 50-237/90019(DRP); 50-249/90019(DRP).

(Closed) LER (249/90006(DRP)): Failure to Establish Appropriate Fire Protection Due to Procedure Deficiency. This event and corresponding corrective actions were discussed in inspection report 50-237/90017(DRP); 50-249/90017(DRP).

(Closed) LER (237/90012(DRP)): Fuel Load Core Monitoring Requirements Violated Due to Management Deficiency. This event and corresponding corrective actions are discussed in paragraph 2 of this report.

No violations or deviations were identified in this area.

4. Plant Operations (61715, 71707 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. The inspectors noted that general housekeeping and contamination control had deteriorated during the Unit 2 refueling outage as compared to recent previous refueling outages. The licensee planned to implement a new material condition/housekeeping/safety inspection program in January 1991.

The inspectors identified that a licensee Quality Control inspector failed to don the required protective clothing while performing a hold-point inspection in a contaminated area contrary to the requirements of Dresden Administrative Procedure (DAP) 12-25, "Radiation Work Permit Process," Steps E.6 and F.1.e.5, and Radiation Work Permit (RWP) 0G067A, on December 3, 1990. The individual subsequently became contaminated and alarmed the Personnel Contamination Monitors (PCMs) when attempting to leave the Radiological Controlled Area (RCA). Following receipt of the PCM alarm, the individual failed to contact the Radiation Protection Department (RPD), per the requirements of DAP 12-13, "Personal External Contamination Surveys," Step F.8.f, and proceeded to perform self decontamination. Failing to follow the requirements of DAPs 12-13 and 12-25 in regard to radiation protection practices is considered to be a violation (50-237/90027-03(DRP)) of Technical Specification 6.2.B which required adherence to radiation control procedures. Following a discussion of the incident with the inspectors on December 4, 1990, the individual then notified the RPD. The RPD documented the incident and completed the appropriate corrective action of counselling the individual involved as to the proper health physics practices at the Dresden Station. As this was considered to be an isolated occurrence, of minimal safety significance and the appropriate corrective action had been completed, a Notice of Violation is not being issued in accordance with 10 CFR 2, Appendix C, Section V.A. The inspector has no further concerns in this area.

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 performed a detailed walkdown of the accessible portions of the Unit 2 containment spray system (CSS), which is a subsystem of the low pressure coolant injection (LPCI) system. The inspectors concluded that the CSS was properly aligned and in adequate condition. The inspectors verified the proper positioning of numerous isolation valves and electrical barriers in containment penetrations. In addition, the inspectors performed a walkdown of the drywell with licensee personnel to ensure that material and equipment utilized during the refueling outage was properly removed or secured.

The inspectors reviewed selected 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.

The inspectors verified that the licensee had implemented controls to assure guidelines presented in Generic Letter 82-12, "Nuclear Power Plant Staff Working Hours" were followed for licensed operators. These restrictions were delineated in DAP 7-21, "Station Policy on Reactor Operator and Senior Reactor Operator Manning Levels and Overtime," Revision 1, which conformed to the Generic Letter. The licensee had also extended these guidelines to Level 1 equipment operators in accordance with the licensee's Nuclear Operations Directive (NOD) OA.13, "Overtime Guidelines." The licensee did not apply these guidelines to Level 2 equipment operators because they were not involved in safety related work. Although the licensee indicated the guidelines were applied to the fuel handling supervisors, the fuel handlers themselves were not covered.

The licensee had developed an in-house computer program which operations engineering assistants utilized to track hours worked and to assure the guidelines were met. The licensee identified four cases during the year of 1990 where these overtime guidelines had been exceeded. Only one of these had been pre-approved by management in accordance with DAP 7-21. The others involved administrative errors, one of which occurred subsequent to utilization of the computer tracking program implemented to correct these errors and resulted from a failure of operations engineering assistants to promptly enter hours into the computer. Licensee corrective action involved counseling of the engineering assistants on the event to ensure prompt data entry. There had been no identified occurrences since that corrective action.

The inspectors noted that DAP 7-21 required pre-approval to exceed the overtime guidelines by the Assistant Superintendent Operations or his designee. The licensee indicated that this designee was the Operating Engineer in charge of personnel. However, Generic Letter 82-12 indicated that such deviation be authorized by the plant manager or his deputy or higher levels of management. The Station Manager was required to review and sign the Overtime Deviation Authorization form only subsequent to the overtime being worked. The intent was that only Senior Management be able to authorize major deviations from the overtime guidelines. At Dresden the pre-authorization prescribed in the administrative procedures was from two supervisory levels below the plant manager with a possibility for a designee at three levels below the plant manager. Therefore, this practice did not appear to meet the intent of the generic letter. However, the one instance where pre-approval was given in 1990 was by the Production Superintendent, one level below the plant manager, which appeared consistent with the Generic Letter 82-12 guidelines.

Inspector concerns resulting from this review and comparison to licensee commitments with respect to overtime guidelines are discussed in paragraph 7.b.

Various operational occurrences were also reviewed as follows:

a. On November 23, 1990, with Unit 2 shutdown in a refueling outage, a scram was received due to noise spikes on Intermediate Range Monitors (IRM) 13 and 15. All SRMs and IRMs actually received spikes. At the time, one control rod was partially withdrawn for testing. The cause was identified to be a voltage spike due to a faulty relay in the control logic for the Low Pressure Coolant Injection (LPCI) system. The relay was replaced. A similar occurrence with IRMs spiking high occurred on December 20, 1990. The licensee has continued to investigate the cause of the spiking problems.

b. On November 27, 1990, Unit 3 entered a 24 hour limiting condition for operating (LCO) in accordance with Technical Specification 3.7.D.3 due to a failure of Nitrogen Makeup Valve AO-1601-59. During the nitrogen makeup surveillance, this valve failed to close completely. This was of concern since this valve also served as a containment isolation valve. Technical Specifications would have allowed closing other valves upstream of this line to provide the isolation function such that the 24 hour LCO would not have been entered. However, one of these valves, AO-1601-58, was in the pumpback system which provided drywell/torus differential pressure control. Since closing this valve would have caused difficulties in maintaining the required differential pressure, it was left open and the 24 hour LCO was entered. However, repairs were completed prior to actually initiating a shutdown.

c. During a plant walkdown on December 7, 1990, the inspectors noted that an access door to the Unit 2 drywell purge and ventilation system downstream of ventilation fan 2-5708A, was open about one to two inches. As this formed a portion of the secondary containment isolation boundary, the concern was that this provided approximately a 72 square inch hole from the turbine building through this boundary. As described in paragraph 6.b., although Unit 2 was in a refueling outage, the current SGTS lineup would cause suction to be drawn from this area even if the actuation was on Unit 3. It was not clear whether this breach was large enough to prevent fulfillment of SGTS function (i.e., the ability to pull a 0.25 inch differential pressure to the atmosphere in secondary containment.) The licensee ran the system with the access door in the as-found condition to ensure that had the SGTS been called upon, the suction created in the ductwork would have pulled the access door shut. As such, the inspectors ascertained that the operability of SGTS was not affected by the open access door. No apparent cause could be ascertained by the licensee.

The inspectors also noted on December 7, 1990, that the Service Air Supply to three of the Unit 3 drywell purge and ventilation fan dampers had been disconnected. No temporary alteration tags were attached to the air lines or to the dampers' operators. Following notification to the licensee, the licensee reconnected the airlines to the dampers which changed position from open to closed. (The system was not in operation at the time.)

A review of Dresden Operating Procedure (DOP) 6600-1, "Normal Venting of Drywell and Torus", Revision 5, indicated that it required disconnection of the air operators on the drywell purge fan inlet and outlet dampers and blocking or tieing the dampers in the open position prior to the operation. This was necessitated since the dampers automatically opened and closed in conjunction with fan operation and the fan was not actually operated in this procedure. A step was also included to reconnect the air operator and unblock or untie the dampers when the operation was complete. A review of the operating history of this system indicated that it was last used for venting Unit 3 on December 5, 1990, for containment pressure control. This should have been performed in accordance with DOP 6600-1. However, it was questionable whether step F.1.b(2) was followed in that the air supply was found disconnected. This is considered to be an unresolved item (50-237/90027-04(DRP)) pending further review of operator involvement and safety significance.

d. On December 8, 1990, while Unit 2 was in the refuel mode, eight Group II automatic primary containment isolation valves closed following the lifting of a field wire on a main control room terminal block. The lead was lifted to facilitate a resistance and meggering check of the Main Steam Isolation Valve (MSIV) pilot solenoid coils, per DES 200-39, "Main Steam Isolation Valve Electrical Maintenance." Further review indicated that an interruption of multiple neutral ground circuits occurred when the lead was lifted. This resulted in a loss of power to the associated seal-in relays, which maintained each of the affected Group II isolation valves in their open positions. Electrical wiring diagram 12E2697 indicated that the neutral ground circuit was designed to be wired, in daisy chain fashion, on the cabinet side of the respective terminal block. The drawing also showed four leads terminated on the cabinet side of the effected terminal point.

However, each terminal block point was physically limited to accommodate a maximum of three leads. In apparent compensation for this design deficiency, one of the four wires, the neutral ground circuit for the Group II valves, was placed on the field side of the terminal block, sharing the same connection point as the MSIV pilot solenoid coils.

DES 200-39 matched the configuration as described on Diagram 12E2697. When DES 200-39 was performed, the electrician found two leads on the field side terminal point. The lifting of the second lead resulted in the valve closure. The apparent root cause of the event was a discrepancy between the plant configuration and the "as-built" drawings. A review of past revisions to Diagram 12E2697 revealed that the original plant design configuration also specified the termination of four leads on the cabinet side of the terminal block point. Based on the physical limitations of the cabinet side terminal block point, the undocumented wiring configuration was estimated to have existed since initial plant startup. This is considered an unresolved item (50-237/90027-05(DRP)) pending NRC review of licensee corrective actions.

The licensee failed to recognize that closure of the Unit 2 Group II containment isolation valves was an ESF actuation and also failed to make the four hour report to the NRC as required per 10 CFR 50.72. The licensee indicated that the rationale for not reporting was that the loss of power occurred in the control circuitry and not the logic circuitry. In other words, the logic circuitry did not de-energize to open a corresponding contact in the control circuitry to cause the closure. As such, the licensee did not classify this as an ESF actuation. The licensee based this distinction on NUREG 1022, "Licensee Event Report System," Section V, which stated the following:

Actuation of multichannel ESF Actuation Systems is defined as actuation of enough channels to complete the minimum actuation logic (i.e. activation of sufficient channels to cause activation of the ESF Actuation System). Therefore, single channel actuations, whether caused by failures or otherwise, are not reportable if they do not complete the minimum actuation logic.

It was evident that the licensee had inferred a meaning that was not intended nor supported by the other portions of NUREG 1022 or its supplements. The paragraph noted by the licensee was intended to specifically explain the non-reportability of single channel actuations versus multichannel actuations. No further meaning can be inferred and, in fact, this paragraph made no attempt to define the logic portion of the circuitry as separate and distinct from other portions of the actuation circuitry (i.e. control circuitry). Section IV of NUREG 1022 provided a restatement of the guidance for 10 CFR 50.73 from the statement of consideration which indicated that the criteria were based on the nature, course and consequences of the event and not on initiating events or causes of events. In addition, Section V of NUREG 1022 indicated that the NRC was interested in both events where an ESF was needed and events where an ESF operated unnecessarily since they should not be challenged frequently or unnecessarily.

10 CFR 50.72(b)(2)(ii) specifically required the reporting of any condition that results in a manual or automatic actuation of any Engineering Safety Feature (ESF). Additionally, NUREG-1022, "Licensee Event Report System," Supplement No. 1, Section II.6, clarified that an ESF actuation includes any automatic, spurious, or manual action that results in the actuation of the device to perform its intended function. In the case of the Group II isolation valves, the intended ESF safety function was the automatic closure of the valves. All ESF actuations were required to be reported (except those expected actuations that result from and were part of preplanned sequence during testing). The failure to make the required report was considered to be a violation (50-237/90027-06(DRP)) of 10 CFR 50.72(b)(2)(ii).

e. Following receipt of upper motor guide bearing high temperature and high vibration alarms on recirculation pump 3B on December 15, 1990, both recirculation pumps were reduced to minimum speed. Recirculation pump 3B was shutdown and it's corresponding suction valve was closed in accordance with Technical Specifications. Total power reduction during the event was from about 95 to 25 percent rated thermal power. The unit remained in single loop operation at the end of the inspection period. On December 22, 1990 a drywell entry was made to visually examine the recirculation pump motor, take oil samples and check a pump motor vibration switch. During the subsequent local leak rate test (LLRT) on the drywell personnel interlock doors on December 23, 1990, the inner door seal failed. Unit 2 was shut down, the seal was repaired and Unit 2 was returned to service on December 26, 1990.

f. In the course of observing refueling operations on November 18, 1990, the inspector noted that a temporary vacuum pump and hose assembly were utilized to augment the filtering capability of the fuel pool clean-up system. This temporary vacuum pump was situated on the top guide of the reactor vessel and pumped refueling water through a hose which exited the drywell cavity, ran several feet across the refueling floor, entered the refueling pool, and led to the fuel pool skimmer surge tank. Various concerns were identified including; (1) whether the use of the pump was controlled by procedures or as part of a temporary alteration/modification program, (2) whether consideration was given to the possibility of rupturing the vacuum hose and lowering the level in the refueling pool, and (3) the availability of indicators and alarms for the refueling pool level. This is considered an unresolved item (50-237/90027-07(DRP)) pending further review in regard to these concerns.

One cited and one non-cited violation and no deviations were identified in this area.

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

a. Maintenance Activities

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

The following items were considered during this review:

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

- Environmental Qualification Preventive Maintenance on the Unit 2 High Radiation Sample Target Rock Solenoid Valves.
- Environmental Qualification Preventive Maintenance on the Unit 2 Main Steam Isolation Solenoid Valves.
- Unit 2 SRM Cable Routing.
- Plant Process Pipe Labeling.
- Calibration of the Unit 2 Turbine Control Valve Pressure Switches.

On November 21, 1990, during performance of an LLRT, clean de-mineralized water (CDW) was secured to the Unit 2 drywell. This caused a plug in Main Steamline (MSL) "A" to deflate and provide a drainpath from the reactor cavity. (The reactor cavity was flooded above the main steamlines at the time.) As the corresponding inboard MSIV had been removed for maintenance, leakage entered the drywell. This was discovered while investigating the receipt of multiple drywell sump level alarms in a short period. Up to one inch of cavity level was lost during the event. Further review indicated the cause to be a failure to follow procedure during MSL plug installation on October 13, 1990.

The work package for this activity prescribed installation in accordance with Dresden Maintenance Procedure (DMP) 200-31, "MSL Plug Installation and Removal." The procedure prescribed inflation of the seal with service air. However, upon completion it was noted that air leakage caused bubble to form in the reactor cavity which obscured fuel handler vision. The maintenance supervisor, having been reminded that CDW had in the past been used to inflate the seals, had the source switched to CDW, contrary to procedure requirements and without informing appropriate management. As outage planning was predicated on the assumption that the inflation source was in accordance with the procedure, the LLRT was allowed to commence on the CDW line. In fact, the LLRT on the Service Air Line had been purposely postponed so as to not affect the seals. Failing to follow the procedure is considered to be a violation (50-237/90027-08(DRP)) of 10 CFR 50, Appendix B, Criterion V. However, this event was indicative of, and in the same time frame as the types of problems encountered during the first part of the current Unit 2 refueling outage. The actual failure to follow procedure occurred prior to the corrective actions taken by plant management as described in inspection report 50-237/90023; 50-249/90023 to address these problems. As such, this event, had it been discovered in the previous inspection period, would have been included as an additional example in the corresponding notice of violation issued with that report. As the licensee had already taken appropriate corrective actions to address this type of concern, a Notice of Violation is not being issued in accordance with exercise of discretion delineated in 10 CFR 2, Appendix C, Section V.G.1.

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:

Nuclear Instrumentation Surveillance
Reactor Vessel Leakage (Hydrostatic) Test
Standby Liquid Control Inservice Testing
Control Rod Drive Friction Testing
Single Reactor Recirculation Pump Operation Surveillance
Control Rod Drive Insertion Timing

On December 17, 1990, the Unit 2 torus to reactor building vacuum breaker (2-AO-1601-20A) was discovered to be leaking excessively into the torus basement area following the pressurization of the drywell to 13 pounds per square inch (psig) during the performance of the ILRT. Maintenance personnel were dispatched and tightened the bolts on the inboard vacuum breaker flange. This effort resulted in the sealing of the flange mating surface and the drywell was subsequently pressurized to 48 psig. The primary containment leakage rate through the degraded flange could not be quantified. However, the leakage rate was estimated to be well in excess of the Technical Specification limit of 1.6 percent, by weight, of the containment air, per 24 hours, at 48 psig. A review of past maintenance activities indicated the vacuum breaker was replaced during the last refueling outage. Further evaluation of the work package identified that the licensee failed to perform an ILRT or LLRT on the effected containment volume following the replacement of the vacuum breaker. This issue is considered to be an unresolved item (50-237/90027-09(DRP)). pending review of specific containment leakage testing requirements.

c. The inspectors reviewed maintenance department overtime practices in consideration of Generic Letter 82-12 and 83-14 guidelines. Maintenance Department Memorandum (MDM) No. 65 prescribed application of the guidelines to appropriate personnel. However, the MDM did not prescribe a break of at least eight hours between work periods as indicated in Generic Letter 82-12 and NOD OA.13. No actual occurrences were noted, however, where this had been exceeded.

Actual implementation of MDM No. 65, began in mid-1990. The methodology utilized for tracking and pre-checking was dependent on the specific maintenance master. During the inspection, the maintenance masters were provided with printouts from the payroll computer system which had been programmed to indicate personnel who had surpassed the guidelines. This was to be utilized to prepare the overtime semi-annual report to the Vice President of BWR Operations. Through this printout, the licensee identified numerous unexpected instances of electrical maintenance exceeding the 72 hours in seven day guidelines. This was because that group had been applying that guideline based on a fixed week and not on a rolling during any seven day period. The other groups had applied this correctly. As a result, the electrical maintenance group changed to a rolling seven day period and the distribution of the computer printout was changed to two week intervals. Although in some cases, tracking methodology utilized was not very formal, this did not appear to be a problem except as noted above. The total number of deviations was minimal; however, additional deviations were expected the last week of the Unit 2 refueling outage. Inspector concerns resulting from this review and comparison to licensee commitments with respect to overtime guidelines are discussed in paragraph 7.b.

One non-cited violation and no deviations were identified in this area.

6. Engineering/Technical Support (71707 and 93702)

a. The inspectors reviewed the guidelines in Generic Letter 82-12 in comparison to overtime worked by the plant technical staff. The licensee indicated that the plant technical staff was not covered under Generic Letter 82-12 and, therefore, the guidelines were not applied to this group. The Technical Staff Supervisor had issued a memorandum on October 6, 1990, that delineated corporate direction that Technical Staff personnel working on safety related work, not work more than 18 hours continuously. This was in response to a recent event at Braidwood in which technical staff personnel worked excessive hours. The memorandum emphasized fitness for duty responsibility. The licensee had taken measures to minimize extended work hours at the start of the current Unit 2 refueling outage by developing a planned schedule for the technical staff major testing evolutions based on 12 to 13 hour work days and adding personnel to backshifts to spread out the work. The licensee identified two instances during the current outage in which personnel exceeded 18 continuous work hours. One was for 20 hours with prior Technical Staff Supervisor approval and in the other instance the individual was sent home just after 18 hours. The licensee did not have a formal tracking mechanism to assure the self-imposed 18 hour guideline was not exceeded, but instead informally relied upon the individual and the Technical Staff group leaders.

The inspector reviewed a sample of the licensee's daily attendance report for Technical Staff personnel for the month of November 1990, in which a refueling outage was conducted. The format was primarily for pay purposes only, such that all instances of exceeding guidelines would not necessarily be identifiable. However, it appeared that several instances of exceeding Generic Letter 82-12 guidelines had occurred with some of this involving types of work applicable to the Generic Letter. A similar sample review for October 1990, a non-outage month did not identify any such instances. In addition, these instances appeared to be heavily dependent on the group within the Technical Staff, most notably with the inservice inspection/inservice testing group. A staffing increase from 67 to 85 individuals between May and November 1990, indicated a concerted effort to increase the size of the plant technical staff. (The large workload was considered a weakness in the last Systematic Assessment of Licensee Performance (SALP) period.) In the same time period, the normal attrition of experienced personnel was about equal to the hiring of experienced personnel. Therefore, the net effect of the increased staffing was the addition of recent college graduates with little or no experience. However, these individuals would be expected to gain experience as time progressed and to alleviate the total workload.

Inspector concerns resulting from this review and comparison to licensee commitments with respect to overtime guidelines are discussed in paragraph 7.b.

b. On November 30, 1990, the licensee identified a problem with the SGTS lineup which could potentially allow flow to bypass the SGTS. Among other locations, the SGTS took a suction from each unit's reactor building ventilation system (RBVS). In order to address a problem identified in the mid-1970s, the licensee had tagged the reactor building ventilation to SGTS isolation valves open with their corresponding breakers racked out such that they would not close on an automatic signal. The original design called for the isolation valve on the unaffected unit to automatically close on a SGTS automatic start signal. This was to prevent flow from the affected unit's RBVS from entering the still normally operating RBVS on the unaffected unit, which would exit to the environs without passing through the SGTS. The licensee was concerned that following an initiation signal on one unit and corresponding closure of the opposite unit's RBVS to SGTS isolation valve, an automatic start signal on the other unit would then result in total isolation of the SGTS. Therefore, a single failure could disable the SGTS. The licensee could find no record of a 10 CFR 50.59 safety evaluation for the racked out isolation valve breakers. The licensee had planned on modifications to the logic to address the original concerns but the modifications were cancelled prior to implementation. The licensee indicated that justification was that operator actions could be taken to initiate reactor building ventilation isolation on the unaffected unit when an automatic signal was received on the opposite unit. This was reflected in procedures such that the opposite unit's RBVS would be manually lined up to the SGTS on a single unit initiation signal. While reviewing applicability of motor operated valve testing to these valves on November 30, 1990, licensee personnel reviewed these previous actions and questioned whether adequate justification had been utilized. The licensee conducted an offsite dose analysis assuming no operator actions with both isolation valves remaining open. These results indicated doses well below 10 CFR 100 guidelines. The licensee planned to develop a modification that would cause both RBVS to automatically lineup to the SGTS on a single unit initiation. The licensee also planned to perform a review of existing out-of-services to ensure that similar long standing cases of system changes through out-of-service did not exist. As indicated in enforcement conference report 50-237/90023; 50-249/90023, the licensee also was developing reforms to the 10 CFR 50.59 safety evaluation process at the facility.

Although the facility change was performed through an out-of-service, the nature and long term existence clearly indicated the necessity of performing a 10 CFR 50.59 safety evaluation to ensure that an unreviewed safety question did not exist. In addition, the inspectors considered the justification for cancelling modifications to rectify the various concerns to be inadequate in that an appropriate basis was not provided as to utilization of manual operator actions in place of the automatic function. Failure to maintain records, which include a written safety evaluation of this facility change, is considered to be a violation (50-237/90027-10(DRP)) of 10 CFR 50.59(b)(1). However, as this issue was licensee identified, an unreviewed safety question by definition did not actually exist, appropriate corrective actions were initiated or planned and due to the age of the initial change, a notice of violation is not being issued in accordance with exercise of discretion delineated in 10 CFR 2, Appendix C, Section V.G.1.

c. On December 19, 1990, the licensee informed the resident inspectors of a problem in regard to Technical Specifications not reflecting a previous modification. The reactor protection system (RPS) scram on generator load reject was modified in 1983 as a result of a GE Technical Information Letter (TIL) recommendation. The limit switches on the control valve fast acting solenoids which provided the scram signal were replaced by pressure switches which actuated on low Electrohydraulic Control (EHC) oil pressure at each control valve. Technical Specification Table 4.1.1 required a functional check surveillance to be performed on this scram function. However, Technical Specification Table 4.1.2 did not require a corresponding calibration check to be performed since it actually was written for the old design. Technical Specification Basis indicated that this was, in fact, an "on/off" type switch for which calibration was not applicable. However, the "new design" pressure switches can be calibrated. Since it was not required, the licensee was unsure whether calibration of these switches had ever been performed. Since the licensee had performed required functional checks but not necessarily calibration checks on this scram function, its operability was questionable. The generator load reject scram was a limiting safety system setting which anticipated the rapid increase in pressure and neutron flux from a control valve closure due to load rejection coincident with a failure of the bypass valves and corresponding Minimum Critical Power Ratio (MCPR) considerations. This was not an immediate problem since Technical Specifications allowed this scram function to be bypassed at less than 45 percent steam flow. Unit 2 was still shutdown for a refueling outage and

Unit 3 was at less than 45 percent steam flow since it was in single loop operation due to recirculation pump motor problems. This is considered an unresolved item (50-237/90027-11(DRP)) pending further review of this modification with respect to 10 CFR 50.59 requirements.

No violations or deviations were identified in this area.

7. <u>Safety Assessment/Quality Verification (40500)</u>

a. The inspector observed the licensee's Start-Up On-Site Review Committee meeting held on December 11, 1990. These meetings were routinely held prior to start-up to review plant work activities accomplished during the refueling outage. The content and conduct of this meeting appeared to effectively contribute to the prevention of problems during start-up monitoring and evaluating the current plant status.

b. The inspector reviewed previous licensee/NRC correspondence to determine licensee commitments to Generic Letters 82-12, "Nuclear Power Plant Staff Working Hours", and 83-14 "Definitions of Key Maintenance Personnel." In a letter from T. J. Kovach (CECo) to A. B. Davis (NRC) dated October 4, 1989, the licensee responded to NRC concerns that CECo did not appear to have sufficient measures in place to ensure that safety-related work was not jeopardized by personnel having worked too many hours. The licensee committed to develop a new corporate Nuclear Operations Directive (NOD) that was to ensure uniform overtime policy governing safety-related work in accordance with the guidelines included in Generic Letters 82-12 and 83-14. This commitment indicated that the NOD would provide guidance applicability beyond the Technical Specification minimum shift crew composition and that included in this would be maintenance personnel and chemistry and radiation protection personnel. As such, the commitment was not clear as to what other groups beyond those specifically mentioned would also be included. The commitment also indicated an appropriate level of management would be designated to assure that overtime was approved prior to the work occurring. The subject NOD, OA.13, was issued on March 15, 1990.

As indicated in paragraphs 4 and 6.a, NOD OA.13 did not extend the guidelines to the fuel handlers or to technical staff personnel and, as such, inclusion of these groups was not reflected in plant practice. As the fuel handlers performed safety related work in the movement of fuel assemblies and the technical staff performed in-plant safety-related work such as local leak rate testing and inservice inspections, the licensee's commitment would appear to apply to these groups. In addition, as described in paragraph 4, although the one pre-approved overtime deviation for operations during 1990 was from an appropriate level of management, that allowed by DAP 7-21 was not consistent with Generic Letter 82-12 guidance. In addition, MDM No. 65 did not contain a requirement for a break of eight hours between shifts in accordance with Generic Letter 82-12 and NOD OA.13. This is considered an unresolved item (50-237/90077-12(DRP)) pending completion of this inspection activity with respect to other plant organizations.

c. On November 30, 1990, the licensee received a Notice of Violation and Proposed Imposition of Civil Penalty associated with the use of a temporary sample pump in the drywell manifold sampling system. On December 17, 1990, the inspectors observed that the Civil Penalty had not been posted. This is considered to be a violation (50-237/90027-13(DRP)) of 10 CFR 19.11 in that the Proposed Imposition of a Civil Penalty was not posted within the required two days of receipt. Discussions with station Regulatory Assurance personnel, the group which was responsible for initiating the posting process per Dresden Administrative Procedure (DAP) 2-17, "Required Posting of Documents", revealed some confusion existed over the posting requirements. The responsible supervisor believed it was not required to be posted until the station submitted their response to the Notice of Violation and Proposed Imposition of Civil Penalty. The licensee posted promptly following identification by the inspectors.

The cause of the posting failure was related to the inadequate training of Regulatory Assurance group personnel of the requirements of DAP 2-17. The problem of inadequate training of administrative requirements was identified as the root cause associated with a past violation of 10 CFR 50, Appendix B, Criterion II, as delineated in inspection report 50-237/90023; 50-249/90023. As a result of the previous violation, the licensee was developing a program to matrix administrative training requirements with position descriptions with full implementation planned for the spring of 1991. The purposed training program was to ensure personnel were adequately trained on the administrative procedures they were required know to perform their specific duties. As this was considered to be an isolated occurrence in regard to posting requirements and appropriate corrective actions had been formulated to address the root cause, a Notice of Violation is not being issued in accordance with 10 CFR 2, Appendix C, Section V.A. The inspectors have no further concerns in this area.

One non-cited violation and no deviations were identified in this area.

8. Systematic Evaluation Program (SEP) Items

NUREG 1403, "Safety Evaluation Report related to the full-term operating license for Dresden Nuclear Power Station," Table 2.1 identified SEP Integrity Plant Safety Assessment Report (IPSAR) topic resolutions to be confirmed by the NRC Region III office. Of the 22 items in that report, eleven were indicated as already closed in previous inspection reports, leaving eleven remaining items to be closed. The intent is for the licensee to verify closed the remaining items with identification of the closing rationale to the NRC and a sample NRC inspection of these items to gain reasonable confidence in the licensee's information. Any items not yet closed would be identified to the NRC with anticipated closure dates. In that endeavor, the inspectors verified actual completion of the following items which the licensee indicated were closed.

Item 18 - Topic VI-10.B,2.12 (Supp.1)
Item 19 - Topic VI-10.B,4.23.2
Item 22 - Topic VIII-2, 4.26.2

Completion of this sample inspection as the licensee finishes the determination of the status of the remaining SEP items is considered an open item (50-237/90027-14(DRP)).

No violations or deviations were identified in this area.

9. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether it is an acceptable item, an open item, a deviation or a violation. Unresolved items disclosed during this inspection are discussed in paragraphs 4.c, 4.d, 4.f, 5.b, 6.c and 7.b.

10. Open Items

Open items are matters which have been discussed with the licensee which will be further reviewed by the inspector and which involved some actions on the part of the NRC or licensee or both. The one open item disclosed during the inspection is discussed in paragraph 8.

11. Report Review

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

12. Exit Interview

The inspectors met with licensee representatives (denoted in Paragraph 1) on December 28, 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.

Commonwealth Edison
1400 Opus Place
Downers Grove, Illinois 60515

February 15, 1991

Mr. A. Bert Davis
Regional Administrator, Region III
U.S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, IL 60137

Subject: Dresden Nuclear Power Station Units 2 and 3
Response to Notice of Violation Associated
with Inspection 50-237/90027; 50-249/90026
NRC Docket No. 50-237 and 50-249

Reference: W.D. Shafer letter to Cordell Reed dated
January 17, 1991 transmitting NRC Inspection
Report 50-237/90027; 50-247/90026

Mr. Davis:

This letter provides the Commonwealth Edison Company (CECo) response (attached) to the subject violation transmitted by the referenced NRC Inspection Report for Dresden Station. The violation involved failure to report to the NRC an Engineered Safety Feature actuation in accordance with 10 CFR 50.72.

If your staff has any questions or comments concerning this letter, please refer them to Rita Radtke, Compliance Engineer at 708/515-7284.

Very truly yours,

T. J. Kovach
Nuclear Licensing Manager

cc: B.L. Siegel, Project Manager - NRR
D.E. Hills, Senior Resident Inspector
NRC Document Control Desk

RR:TK:lmw
ZNLD742/17

NOTICE OF VIOLATION

Commonwealth Edison Company
Dresden Nuclear Power Station

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

During an NRC inspection conducted on November 17 through December 29, 1990, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions, "10 CFR Part 2, Appendix C (1990), the violation is listed below:

> 10 CFR 50.72(b)(2)(ii) requires the NRC to be notified within four hours of the occurrence of any event or condition that results in manual or automatic actuation of any Engineered Safety Feature (ESF).
>
> Contrary to the above, the unexpected closure of several Unit 2 Group II primary containment isolation valves upon lifting of an electrical lead during post-maintenance testing on December 8, 1990, constituted an automatic actuation of an ESF and the NRC was not notified of the occurrence.
>
> This is a severity level IV violation (Supplement I).

DISCUSSION

Dresden Station management carefully reviewed the circumstances surrounding the closure of several of the Group II isolation valves. The valve closures were not the result of a Group II signal, real or spurious. Neither channel of the Group II isolation logic circuitry actuated. The spurious closure of the valves was caused by de-energizing of the seal-in relays associated with several of the Group II valves.

Page 13 of NUREG-1022, "Licensee Event Report System," reads as follows:

> "Actuation" of multichannel ESF Actuation Systems is defined as actuation of enough channels to complete the minimum actuation logic (i.e., activation of sufficient channels to cause activation of the ESF Actuation System).

As neither Group II isolation channel had actuated, it was determined that the closure of these few valves did not constitute an ESF actuation. -

Discussions were held with the Resident Inspectors concerning the reportability of this event. The Inspectors believed that the event was reportable, citing an internal NRC memorandum which discussed another licensee's proposal to define valid ESFs as resulting only from valid ESF signals. The focus of this memorandum defines an ESF actuation as the actuation of a component of an ESF system--in Dresden's case the closure of several Group II isolation valves. Commonwealth Edison is now aware of this position as to what constitutes an ESF actuation. By the time these discussions were held, several days had passed and the four hour reportability window had expired.

An informal survey was conducted of other Region III utilities to determine how the Dresden event would have been reported. Responses included both reportable and non-reportable. We suggest a continuing dialog with the NRC to share appropriate information (such as the internal NRC memorandum) in order to further refine our reportability determinations.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

Following discussions with the NRC on ESF actuations, an Emergency Notification System (ENS) report was made in accordance with 10 CFR 50.72(b)(2)(ii) on February 4, 1991.

CORRECTIVE ACTIONS TAKEN TO PREVENT FURTHER NONCOMPLIANCE

To assist in making 10 CFR 50.72 reportability determinations, a memorandum will be issued by February 19, 1991 to the operating shift personnel providing this broader guidance on what constitutes an ESF. This guidance will be incorporated into an appropriate station procedure by May 31, 1991.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on February 4, 1991 when all reportability requirements were met.

ZNLD742/18

TAB 17

DRESDEN 2 & 3

FIRE PROTECTION PROGRAM DOCUMENTATION PACKAGE

Inspection Report No. 50-237/91004 and 50-249/91004

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

RECEIVED MAR 7 1991

Revision 8
April 1992

MAR 5 1991

Docket No. 50-237
Docket No. 50-249

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Licensing Department - Suite 300
Opus West III
1400 Opus Place
Downers Grove, IL 60515

Gentlemen:

This refers to the routine safety inspection conducted by Mr. J. A. Holmes of this office on January 22-29 and a walkdown on February 13, 1991, of activities at the Dresden Nuclear Power Station, Units 2 and 3, authorized by NRC Operating Licenses No. DPR-19 and No. DPR-25, and to the discussion of our findings with Mr. E. D. Eenigenburg at the conclusion of the inspection. The purpose of this inspection was to review the implementation of the routine fire protection program.

The enclosed copy of our inspection report identifies areas examined during the course of the inspection. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations, and interviews with personnel.

During this inspection, certain of your activities appeared to be in violation of NRC requirements, as described in the enclosed Notice. A written response is required.

In accordance with 10 CFR 2.790 of the Commission's regulations, a copy of this letter, the enclosures, and your response to this letter will be placed in the NRC Public Document Room.

The responses directed by this letter and the accompanying Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Action of 1980, PL 96-511.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

M. A. Ring, Chief
Engineering Branch

See Attached for Enclosures
and Distribution

Enclosures and Distribution

Enclosures:
1. Notice of Violation
2. Inspection Reports
   No. 50-237/91004(DRS)
   No. 50-249/91004(DRS)

cc w/enclosures:
D. Galle, Vice President -
  BWR Operations
T. Kovach, Nuclear Licensing
  Manager
E. D. Eenigenburg, Station Manager
DCD/DCB (RIDS)
OC/LFDCB
Resident Inspectors - Dresden,
  LaSalle, and Quad Cities
Richard Hubbard
J. W. McCaffrey, Chief
  Public Utilities Division
Robert Newmann, Office of Public
  Counsel, State of Illinois
  Center

NOTICE OF VIOLATION

Commonwealth Edison Company
Dresden Nuclear Station
Units 2 and 3

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

As a result of the inspection conducted January 22-29, and February 13, 1991, and in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions", 10 CFR Part 2, Appendix C, (1990) (Enforcement Policy) the following violation was identified:

Amendment No. 106 to Provisional Operating License No. DPR-19 (Unit 2) and Amendment No. 101 to facility Operating License No. DPR-25 (Unit 3) requires the licensee to maintain in effect all provisions of the approved fire protection program for Dresden Unit 2 and Unit 3.

As part of the approved program, the licensee committed to install and maintain the fire detection and alarm system in accordance with the National Fire Protection Standard No 72E, which required the linear thermal detectors to be tested every six months.

Contrary to the above, the licensee failed to conduct the six month surveillance test on the linear thermal detectors in safety-related fire zones 1.1.1.1 and 1.1.2.1 since July 31, 1989.

This is a Severity Level IV violation (Supplement 1).

Pursuant to the provisions of 10 CFR 2.201, you are required to submit to this office within thirty days of the date of this Notice a written statement or explanation in reply, including for the violation: (1) the corrective actions that have been taken and the results achieved; (2) the corrective actions that will be taken to avoid further violations; and (3) the date when full compliance will be achieved. Consideration may be given to extending your response time for good cause shown.

3/5/91
Dated

M. A. Ring, Chief
Engineering Branch

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-237/91004(DRS); No. 50-249/91004(DRS)

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

Licensee: Commonwealth Edison Company
Opus West III
1400 Opus Place
Downers Grove, IL 60515

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

Inspection At: Morris, Illinois

Inspection Conducted: January 22-29 and February 13, 1991

Inspector: Jeff Holmes 3-5-91
J. A. Holmes Date

Approved By: F. J. Jablonski Jr 3-5-91
F. J. Jablonski, Chief Date
Maintenance and Outage Section

Inspection Summary
Inspection on January 22-29, and February 13, 1991 (Reports No. 50-237/91004(DRS); No. 50-249/91004(DRS))
Areas Inspected: Routine, unannounced inspection to assess the implementation of the licensee's fire protection program, which included a review of licensee action on previous inspection findings, a review of the completed fire protection surveillances, fire protection audits, fire reports and observation of a fire drill. An inspection was performed of tools required for hot shutdown and of equipment required for cold shutdown repair. The inspector utilized modules 30703, 64704, and 92701.
Results: Of the areas inspected one apparent violation and one unresolved item were identified. The [illegible] identified the failure to develop and implement a surveillance [illegible] near thermal detectors located in fire zones 1.1.1.1 and 1.1.2.1 [illegible]). The unresolved item was about the reportability requirements when [illegible] fire pumps are inoperable (Paragraph 3.c.). In general, the licensee's implementation of the fire protection program was good, although some areas of improvement are needed.

The following strengths were identified in the licensee's fire protection program:

- The fire marshal appeared knowledgeable in fire protection systems and initiated action regarding a trend of transformer fires.

- The fire marshal and the assistant fire marshal were dedicated and professional in addressing concerns.
- Overall implementation of the routine fire protection program appeared to be good.

The following weakness was observed:

- In 1989, the licensee and the NRC identified a lack of surveillance testing for the linear thermal detection. When the inspector returned to evaluate licensee action in this area during this inspection, the testing was still not being conducted and the licensee's corrective actions had not been accomplished (Paragraph 2.d.).

DETAILS

1. Persons Contacted

Commonwealth Edison Company (CECo)

*E. Eenigenburg, Station Manager
*R. Black, Assistant Fire Marshal
*M. Churilla, Technical Staff Engineer
*M. Dillon, Fire Marshal
*L. Gerner, Technical Superintendent
*R. Jackson, Technical Staff Group Leader
*K. Kociuba, Quality Assurance Superintendent
*K. Peterman, Regulatory Assurance Supervisor
*M. Strait, Technical Staff Supervisor
*E. Skowron, Technical Staff Engineer
*G. Smith, Operations Assistant Superintendent
*B. Whalen, Assistant Technical Staff Supervisor

The inspector also contacted other licensee personnel during the course of the inspection.

*Denotes those attending the January 29, 1991, exit meeting.

2. Licensee Action on Previous Inspection Findings

a. (Open) Unresolved Item (237/88010-01 (DRS); 249/88012-01(DRS)): It was the inspector's concern that a fire in the decommissioned Unit 1 may expose operating Unit 2 safety-related areas. The licensee has requested a change to the required fire protection program for Unit 1, as indicated in a letter dated November 1, 1989, to the NRC's Office of Nuclear Reactor Regulation (NRR) regarding the Supplement to Proposed Amendment to Reflect Non-Operating Status. The inspector discussed the concern with NRR and this item will remain open pending resolution from NRR.

b. (Closed) Unresolved Item (237/88010-02(DRS); 249/88012-02(DRS)): The licensee's methodology of pulling fuses is considered a hot shutdown repair, which is not permitted by Appendix R. The licensee had previously submitted an exemption request for fuse pulling, which was addressed in the safety evaluation attached to a letter dated July 6, 1989. The letter indicated that Region III was to verify the licensee's ability to perform the identified short-term hot shutdown repairs in a timely manner.

   On February 13, 1991, the inspector verified the licensee's ability to perform short term hot shutdown repairs regaring the replacement of blown control power fuses for the swing diesel generator starting controls, and removal of 20 control power fuses for the reactor relief valves. The proposed manual actions could be performed in a timely manner and no discrepancies were noted. This item is closed.

c. (Closed) Open Item (237/88030-01(DRS); 249/88031-01(DRS)): Due to the unique design of fire wrap access covers to two pull boxes, it was requested that 3M Company review the installation of this design to ensure that the fire rating had not been invalidated.

The licensee received a letter dated May 3, 1989, from the 3M Company, which indicated that if the installations were installed according to the drawings, then the installation would provide one hour of fire protection. Based on the response, this item is closed.

d. (Closed) Open Item 237/89013-01(DRS); 249/89012-01(DRS)): In the original item, the inspector had requested the six month functional test for the linear thermal detectors installed in fire zones 1.1.1.1 and 1.1.2.1. The test had not been developed; however, the licensee indicated that a recent audit had identified the same concern, and the surveillance procedure was in the process of being developed. The licensee indicated to the inspector that the surveillance would be completed by July 21, 1989.

During the current inspection, the inspector requested the completed six month functional test for the same linear thermal detectors in fire zones 1.1.1.1 and 1.1.2.1. The licensee indicated that the surveillance test had not yet been approved. The licensee's lack of surveillance testing for the thermal detectors has been upgraded to a violation (237/91004-01(DRS); 249/91004-01(DRS)) of the approved fire protection program that required the detectors to be tested every six months according to the National Fire Protection Association (NFPA) Standard on Automatic Fire Detectors (NFPA 72E).

3. Routine Fire Protection Program Review (64704)

This inspection consisted of a review of completed fire protection surveillances, fire protection audits, fire reports and an observation of a fire drill. Inspections were performed of tools required for hot shutdown and of equipment required for cold shutdown.

a. Fire Protection Surveillance

The inspector reviewed a sample of the licensee's completed surveillance procedures as listed below:

DFPP 4123-6, "Unit 2/3 Diesel Fire Pump Annual Capacity Check," Revision 5

DFPP 4123-7, "Unit 1 Fire Pump Annual Capacity Test," Revision 5

DFPS 4145-1, "Cardox System Semi-Annual Maintenance Test Data Sheet," Revision 3

DFPS 4183-4, "Unit 2 Heat/Smoke Detector Semi-Annual Operability Test," Revision 0

DFPS 4183-5, "Unit 3 Heat/Smoke Detector Semi-Annual Operability Test," Revision 0

DFPS 4183-6, "Unit 1,2,3, Heat/ Smoke Detector Semi-Annual Operability Test," Revision 0

No unacceptable items were identified; however, the following observation was noted:

(1) Annual Diesel Fire Pump Test

The inspector observed that the fire pump surveillance test results (dated April 5, 1990) were significantly different than the fire pump shop test curve. Procedure Number DFPP 4123-6, Revision 5, verified that the fire pump was functioning properly by trending pump performance. Trends of the pump test results for at least four years did not indicate problems with the pump; however, based on the discrepancies between the fire pump surveillance test results and the fire pump shop test curve, the licensee agreed to review this concern and take appropriate actions.

b. Fire Protection Audits

(1) Technical Specification 6.0.H.1 requires an independent fire protection and loss prevention program inspection and audit be performed at least once per 12 months utilizing either qualified off-site licensee personnel or an outside fire protection firm.

The last Annual Fire Protection Inspection Report dated April 10-14, 1989, identified findings and observations that were either addressed or were scheduled to be addressed by the licensee's staff. No unacceptable resolutions were observed.

(2) Technical Specification 6.0.H.2 required an inspection and audit of the fire protection program to be performed by a qualified outside fire consultant at least once every 36 months.

The triennial inspection of May 8, 1990, identified items that were brought to management's attention, and were resolved by the licensee. No discrepancies were observed in this area.

c. Deviation Report Review

Deviation Report (DVR) 2/3-90-130 states, "On November 20, 1990, at 0147 hours, with Unit 2 in the Refuel mode and Unit 3 in the Run mode at 95% of rated core flow, a simultaneous coolant system failure of the Unit 1 and the Unit 2/3 diesel driven fire pumps (DFPs) occurred during weekly operability testing."

The DVR indicated that Unit 2/3 diesel fire pump failed due to the rupture of its engine coolant hose. The apparent cause of the rupture was a small tear/split from normal deterioration. This tear/split then propagated into the eventual rupture. The DVR indicated that the Unit 1 diesel fire pump had previous problems with its coolant system and the exact cause would not be determined until the diesel was disassembled by the vendor. According to the DVR, immediate corrective actions were taken to replace the failed cooling water hose of the Unit 2/3 DFP, which was completed approximately nine hours later.

The licensee indicated that this was a non-reportable event. This position does not appear consistent with Generic Letter 86-10, which indicated that the licensee is to report deficiencies in the Fire Protection Program which meet the criteria of 10 CFR 50.72 and 10 CFR 50.73. This concern was discussed with the NRR project manager on February 26, 1991, and is considered an Unresolved Item (237/91004-02(DRS); 249/91004-02(DRS)).

d. Fire Drill

On January 22, 1991, at approximately 3:30 p.m. a fire drill was initiated when a trouble and fire alarm was received in the control room from the Unit 2 diesel generator room. The fire drill postulated a fire as a result of an oil spill at the Unit 2 diesel generator. The carbon dioxide system was considered out of service and not operable in the both the automatic and manual mode. The fire brigade responded fully dressed within five minutes. The brigade leader was assertive and appeared knowledgeable in directing his team in attacking the fire. The fire brigade performance was good. During the critique, the inspector indicated that all members of the fire brigade should be equipped with self contained breathing apparatus (SCBA). The licensee indicated that normally during refueling outages, due to time required to clean and maintain the SCBA, it was decided that only two fire brigade personnel utilize SCBA. The inspector informed the licensee to consider requiring all fire brigade members to utilize SCBA during the fire drill in order that the fire brigade members become more proficient in the use of SCBA.

e. Redundant Safety-Related Cable

The inspector verified the power cables for the control rod drive pump 2A-302-3 and power cables from the isolation condenser valve MO2-1301-1 were adequately separated as required by Appendix R. No unacceptable items were observed.

f. Safe Shutdown Repair Equipment and Tools

The licensee has been granted several exemptions about hot shutdown repairs. Specific pieces of equipment such as fuse pullers and fuses, are required to be readily available to accomplish hot shutdown repairs in a timely manner. Several equipment boxes and the safe shutdown equipment cart were inspected to ensure that the proper equipment was available. In addition, cold shutdown repair equipment was also inspected. No unacceptable items were observed.

g. Fire Reports

The inspector reviewed the fire reports for 1989 and 1990. The fires that occurred consisted of shorts in motor windings, electrical faults in breakers, failure of pump bearings, water leak shorting a breaker, and so forth. The reported fires in many of the cases were small and insignificant and were immediately identified by plant personnel or fire detection equipment. There was, however, a trend developing regarding the fires in control transformers in nonsafety-related areas where the equipment was not maintained at the same level as the equipment in safety-related areas. The fire marshal informed the appropriate personnel to address this concern. As a result, the licensee's proposed corrective actions included replacement of existing control transformers with new ones that have built in fuse blocks. The work will be done during routine preventive maintenance of 480 V breakers or during any corrective maintenance work. The work is tentatively expected to begin no later than April 15, 1991.

h. Plant Observations

The inspector observed several areas of the reactor building and turbine building that included several hose stations, extinguishers, sprinkler valves, emergency lights and housekeeping. The inspector concluded that the equipment was well maintained. Housekeeping in these areas was good.

3. Exit Interview

The inspector met with licensee representatives (denoted in Paragraph 1) on January 29, 1991, and summarized the scope and findings of the inspection. The likely informational content of the inspection report was discussed with regard to documents reviewed during the inspection. The licensee did not identify any of the documents as proprietary. The inspector also conducted a walkdown of fire areas on February 13, 1991, which resulted in no new findings.

Commonwealth Edison
1400 Opus Place
Downers Grove, Illinois 60515

March 27, 1991

Mr. A. Bert Davis
Regional Administrator
U.S. Nuclear Regulatory Commission
799 Roosevelt Road-RIII
Glen Ellyn, Il 60137

Subject: Dresden Nuclear Power Station Units 2 and 3
Response to Notice of Violation Associated
with Inspection 50-237/91004; 50-249/91004
NRC Docket Nos. 50-237 and 50-249

Reference: M.A. Ring letter to Cordell Reed dated
March 5, 1991 transmitting NRC Inspection
Report 50-237/91004; 50-249/91004.

Mr. Davis:

This letter provides the Commonwealth Edison Company (CECo) response (attached) to the subject violation transmitted by the referenced NRC Inspection Report for Dresden Station. The violation involved failure to conduct a surveillance test for the linear thermal detectors located in specified fire zones.

If your staff has any questions or comments concerning this letter, please refer them to Rita Radtke, Compliance Engineer at (708) 515-7284.

Very truly yours,

T. J. Kovach
Nuclear Licensing Manager

cc: B.L. Siegel, Project Manager, NRR
D.E. Hills, Senior Resident Inspector
Document Control Desk (Washington, D.C.)

RR/TK/lmw
ZNLD810/21

Commonwealth Edison Company
Dresden Nuclear Station
Units 2 and 3

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

As a result of the inspection conducted January 22-29, and February 13, 1991, and in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions", 10 CFR Part 2, Appendix C, (1990) (Enforcement Policy) the following violation was identified:

> Amendment No. 106 to Provisional Operating License No. DPR-19 (Unit 2) and Amendment No. 101 to facility Operating License No. DPR-25 (Unit 3) requires the licensee to maintain in effect all provisions of the approved fire protection program for Dresden Unit 2 and Unit 3.
>
> As part of the approved program, the licensee committed to install and maintain the fire detection and alarm system in accordance with the National Fire Protection Standard No. 72E, which required the linear thermal detectors to be tested every six months.
>
> Contrary to the above, the licensee failed to conduct the six month surveillance test on the linear thermal detectors in safety-related fire zones 1.1.1.1 and 1.1.2.1 since July 31, 1989.
>
> This is a Severity Level IV violation (Supplement 1)

DISCUSSION

In June 1989, Dresden Station began development of a surveillance procedure to conduct six month surveillance testing on the linear thermal detectors located in fire zones 1.1.1.1 and 1.1.2.1. Work request D84775 and a special procedure were written and the surveillance was performed on July 31, 1989 by the Electrical Maintenance Department.

A permanent procedure was then drafted and routed for Station preliminary review. This permanent procedure included a provision to incorporate the new surveillance in the Dresden Station General Surveillance (GSRV) computer program upon issuance of the new procedure. The GSRV computer program is used to notify cognizant personnel of pending due dates for various surveillance tasks. However, due to significant delays in the preliminary review process, the procedure was not completed and issued within the time frame originally anticipated. As a result, the GSRV computer program was never updated and two surveillance tests were missed.

During the inspection on January 22, 1991, the two missed surveillances were identified. The missed surveillances resulted from an apparent deficiency in Dresden Station's process for initiating new procedures. No mechanism existed to guarantee that surveillances would be conducted if necessary prior to issuance of a permanent station procedure.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. Work Request D98032 to perform the required surveillance test on the linear thermal detectors in safety-related fire zones 1.1.1.1 and 1.1.2.1 was initiated and completed on January 27, 1991, and the results were found to be satisfactory.

2. A request to include this surveillance immediately in The Dresden Station General Surveillance Program (GSRV) was initiated on March 12, 1991 (GSRV #D00Z418307-D12-01).

3. The permanent station procedure, Dresden Fire Protection Surveillance (DFPS) 4183-7, entitled "Linear Thermal Detection Semi-Annual Surveillance" will be approved by April 5, 1991.

CORRECTIVE ACTIONS TAKEN TO PREVENT FURTHER NONCOMPLIANCE

Dresden Administrative Procedure (DAP) 9-2, "Procedure and Revision Processing," will be revised by June 30, 1991 to add a requirement for the procedure originator to contact the Department Surveillance Coordinator to initiate requests for any new surveillances or existing surveillances where the interval is being changed, to be included in The Station General Surveillance Program (GSRV) at the beginning of the procedure writing process rather than wait for issuance of the procedure if a commitment is involved. This new mechanism will ensure that any surveillance procedures are being written or revised.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Full compliance was achieved on January 27, 1991 when the surveillance for Fire Zones 1.1.1.1 and 1.1.2.1 was conducted and on March 12, 1991 when a request was submitted to include this surveillance in the Dresden Station General Surveillance Program.

DRESDEN 2&3

FIRE PROTECTION PROGRAM DOCUMENTATION PACKAGE

Fire Protection Technical Specifications and License Condition

Controlled copies of the fire protection Technical Specifications and License Condition are assigned by the Nuclear Licensing Administrator to Station and Station Nuclear Engineering personnel.

Tab 18

DRESDEN INSPECTION REPORT SUMMARY
237/93002; 249/93002

Inspectors: D. Schrum

Inspection Scope: Fire Protection

Inspection Period: January 11-15 and February 18-22, 1993

Violations	Non-Cited Violations	Unresolved Items	Open Items
0	0	0	0

Summary:

+ Steady improvements in the fire protection program. (p. 1)

+ Staff is knowledgeable. (p. 1)

+ Strengths included correcting hardware deficiencies, performing surveillances, and training fire brigagde members. (p. 1)

+ Fire doors and combustibles were well controlled. (p. 1)

+ Critiques of fire brigade drills were performed well. (p. 1)

- Reliability and material condition of the diesel driven fire pumps was poor. (p. 1, 3)

- Concerns with the reliability of the Unit 1 loop fire main and the over use of repetitive checklists during audits. (p. 1,4-5)

0 Housekeeping was excellent prior to outage, could have been improved during the outage. (p. 2)

- Poor PM on the diesel fire pumps. (p. 3)

0 Plans are underway to replace the diesel fire pumps, it has an improved PM schedule and will be placed on the Technical Issues List. (p. 4)

+ Conditions of the batteries has improved. (p. 4)

- Have been numerous tamper switch maintenance problems on fire protection valves. (p. 5)

ZNLD710/252

NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

MAR 2 1993

Docket No. 50-237
Docket No. 50-249

Commonwealth Edison Company
ATTN: Mr. L. O. DelGeorge
Vice President
Nuclear Oversight and
Regulatory Services
Executive Towers West III
1400 Opus Place - Suite 300
Downers Grove, IL 60515

MAR 5

Dear Mr. DelGeorge:

This refers to the routine safety inspection conducted by Mr. D. Schrum of this office on January 11-15 and February 18-22, 1993. The inspection included a review of authorized activities for your Dresden Nuclear Power Station, Units 2 and 3. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the inspection report. The inspection included a review of the implementation of the fire protection program and an assessment and evaluation of your actions to take corrective actions for plant problems. Within these areas, we selectively examined procedures and representative records, made observations, and conducted interviews with your personnel.

No violations of NRC requirements were identified during the course of this inspection.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

G. C. Wright, Chief
Engineering Branch

Enclosure: Inspection Reports
No. 50-237/93002(DRS);
No. 50-249/93002(DRS)

See Attached Distribution

Distribution

cc w/enclosure:
M. Lyster, Site Vice President
C. Schroeder, Station Manager
J. Shields, Regulatory Assurance
Supervisor
D. Farrar, Nuclear Regulatory
Services Manager
DCD/DCB (RIDS)
OC/LFDCB
Resident Inspectors-Dresden,
LaSalle and Quad Cities
Richard Hubbard
J. W. McCaffrey, Chief
Public Utilities Division
Robert Newmann, Office of Public
Counsel, State of Illinois
Center
J. Stang, LPM, NRR
State Liaison Officer
Chairman, Illinois Commerce
Commission
T. O. Martin, DRS
W. L. Axelson, DRSS
J. E. Dyer, NRR
E. J. Leeds, NRR
M. J. Jordan, DRS
S. Stasek, SRI, Davis-Besse
W. Hodges, RI
A. Gibson, RII
S. Collins, RIV
K. Perkins, RV

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No: 50-237/93002(DRS); No. 50-249/93002(DRS)

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

Licensee: Commonwealth Edison Company
Executive Towers West III
1400 Opus Place-Suite 300
Downers Grove, IL 60515

Facility Name: Dresden Nuclear Power Station
Units 2 and 3

Inspection At: Morris, Illinois

Inspection Conducted: January 11-15 and February 18-22, 1993

Inspector: F. J. Jablonski for
D. Schrum — 3-2-93 Date

Approved By: F. J. Jablonski
F. J. Jablonski, Chief
Maintenance and Outages Section — 3-2-93 Date

Inspection Summary

Inspection on January 11-15 and February 18-22, 1993 (Reports No. 50-237/93002(DRS), No. 50-249/93002(DRS))

Areas Inspected: Routine fire protection inspection of surveillances, equipment, fire brigade training and drills, zebra mussel problems, and fire protection audits. The inspector utilized selected portions of NRC inspection procedures 64704 and 92702.

Results: Steady improvements continued in the fire protection program. Overall, the fire protection program was considered good. The staff was knowledgeable and had taken appropriate actions to correct issues and problems. Strengths included correcting hardware deficiencies, performing surveillances, and training of fire brigade members. Fire doors and transient combustibles were well controlled. Critiques of fire brigade drills were performed well. Control of fire protection concerns was adequate in the area of plant modifications. Reliability and material condition of the diesel driven fire pumps was poor. Preventive maintenance was being increased and the pump/engines were being considered for replacement. Concerns were identified with the reliability of the Unit 1 loop fire main and the overuse of repetitive checklists during audits.

DETAILS

1. Persons Contacted

Commonwealth Edison Company (CECo)

*R. Black, Assistant Fire Marshal
E. Carroll, Regulatory Assurance
*L. Cartwright, Assistant Technical Staff Supervisor
*A. D'Antonio, Supervisor Quality Verification
*M. Dillion, Fire Marshal
*R. Flahive, Technical Superintendent
*B. Gurley, Regulatory Assurance
*K. Housh, Technical Staff Fire System Engineer
*J. Kotowski, Operations Manager
*D. Mershon, Technical Staff Fire Protection Engineer
M. Nagle, Fire Brigade Instructor
*D. Roberts, Corporate Fire Protection Engineer
R. Stachniak, Operating Engineer
D. Winchester, Internal Audit Group Superintendent

U. S. Nuclear Regulatory Commission (NRC)

M. Leach, Senior Resident Inspector
M. Peck, Resident Inspector

*Denotes those individuals attending the exit meeting on February 22, 1993.

2. Routine Fire Protection Program Review (64704)

This inspection consisted of observations of plant areas and reviews of fire protection surveillances, maintenance on fire protection equipment, fire brigade training and drills, fire reports, deviation reports, work requests, safety evaluations, controls to prevent bio-fouling by zebra mussels, and audits of fire protection activities.

2.1 Observation of Plant Areas

The inspector observed several areas of the reactor building and turbine building. The observation included hose stations, extinguishers, sprinkler valves, emergency lights, and housekeeping. The inspector determined that the equipment was being maintained in good condition. Housekeeping was excellent prior to the outage, although housekeeping could have been improved during outage activities. For example, rags were left in work areas and large quantities of anti-contamination clothing were allowed to accumulate. The majority of the wood used during outage activities was treated to make it fire resistant. Fire resistant plastic was also being used. Lubricants and oils were properly stored in fire resistant cabinets or in steel containers. Equipment areas were mostly free of oil as the result of equipment leaks. Appropriate controls for cutting and welding operations were being enforced. No discrepancies were noted with sprinklers or with fire main valves or headers. Halon bottles were at appropriate pressures and fire extinguishers had been inspected and had a current inspection date. No areas were noted where sprinklers should have been installed but were not already in place. Controls were being maintained for transient combustibles and fire doors. All fire doors were functional and temporary outage cables had been routed to ensure that the fire doors were operable.

2.2 Surveillances

The inspector reviewed completed surveillance procedures for 1992. The surveillances were performed accurately and on time. The observations and discrepancies were corrected with the exception of the Unit 2/3 diesel fire pump. Numerous engine and pump problems were noted in surveillances DFPP 4123-5, "Unit 2/3 Diesel Fire Pump Weekly Operability." The licensee was making efforts to better utilize surveillance resources based on risk and failure rate of equipment, which helped make resources available for other efforts.

2.3 Maintenance on Fire Protection Equipment

2.3.1 Diesel Fire Pumps

The diesel fire pumps (DFP) were poorly maintained. Very little preventive maintenance (PM) was done. Maintenance history showed that the DFPs had a large number of failures during the 1990 to 1993 time period. The repair data indicated that the DFPs went from failure to failure without any overall corrective actions to correct the situation. The failures were caused by years of neglect when PM efforts were not appropriate for the importance of the DFPs, that is, for fire protection and refilling the condenser following a station blackout.

PM activities did not include replacing parts that deteriorated with age, such as hoses and gaskets, and checking strainers. For example, when one of the DFP engine coolant hoses burst because of age and pressure, the licensee did not replace the other hoses. The hoses were also not put on a PM schedule to be replaced. Other failures included gaskets, radiator caps, packing, and seals. The engine coolant strainer was not on the PM schedule for periodic cleaning. Strainers were only cleaned in the fire main system following a problem. Other system strainers had been cleaned and checked for the first time since their installation more than 20 years ago.

DFP1 engine failed in 1991. The licensee could not pinpoint the exact cause, but the engine had overheated several times in the six months prior to this problem. The engine was replaced but the pump is in poor condition with very little margin to meet its flow requirement. Maintenance history indicated that the reliability of DFP 1 increased after the engine replacement. The pump and engine are scheduled for replacement in 1993. A modification package was approved and the licensee is pursuing an equipment supplier.

Repair data indicated that DFP 2/3 was in poor condition. The reliability was low. The failure rate was high and occurred even though the pump was only operated 40-50 hours per year. As a result of an engine hose failure, DFP 2/3 failed the same time DFP1 failed. The licensee was able to make repairs within 24 hours otherwise the reactors were required to be shut down. The licensee purchased a third DFP that can be temporarily connected until one of the two main pumps are repaired. The problem of shutting down the plants is solved, but the reliability has not been increased much for the two main fire pumps in the event of a fire.

Both DFPs will be replaced in the 1993/1994 time frame. In addition, improved PM procedures are in the concurrence cycle for the existing pumps. Also, The PM schedule now includes checking and cleaning strainers. The technical superintendent stated during the exit that the DFPs would be put on the Technical Issues List, which assures that adequate resources will be devoted for improving the material condition of the DFPs.

2.3.2 Batteries

Surveillance reports indicated that maintenance of the DFP batteries had been a problem including water levels, possible overcharging, and maintaining specific gravity. The licensee had taken action to turn over the maintenance of the batteries to the electrical group during 1992. Following this change the surveillance reports indicated that the condition of the batteries had improved.

2.3.3 Unit 1 Yard Fire Main Loop

The Unit 1 yard fire main loop appeared to be in poor condition. The 1992 fire protection insurance log indicated that the fire loop was inoperable several times in 1991 and 1992. The problems were believed to have occurred because of being disturbed during the installation of the sewage system, and not as a result of the asbestos cement piping being made brittle because of pressure cycling and aging. Maintaining reliability of the loop is important because both main fire loops are required to meet the requirements of 10 CFR 50, Appendix R. Current low reliability makes it questionable whether this system will be available during a fire.

2.4 Fire Brigade, Fire Reports, and Fire Drills

Fire brigade members received extensive training, which included classroom and offsite fire fighting. The onsite fire drill requirements had been met by all brigade members who were listed as qualified. All appropriate drill and training records were properly maintained.

A review of the fire records indicated that the fire brigade was only required to respond twice in 1992. The two events were for a motor fire and a power transformer fire. The small number of responses was indicative of good control of combustibles, cutting/welding activities, and housekeeping.

Recent efforts at improvements for fire fighting include purchasing more equipment to better outfit the fire brigade members, with plans to locate the equipment at strategic locations in the plant. This will allow a faster response to fires.

2.5 Deviation Reports and Work Requests Review

The inspector reviewed open nuclear work requests (NWRs) for fire protection. The backlog was low considering the high number of NWRs that had been performed during the year. The NWRs had been properly prioritized and none of the outstanding work items appeared to be highly safety significant. The backlog had been reduced from 175 to 139 during 1992. In addition, the fire protection Nuclear Tracking System (NTS) backlog had been reduced from 65 to 32 in 1992.

There have been numerous tamper switch maintenance problems on fire protection valves. Many of the problems resulted from old tamper switches and the difficulty in purchasing replacement parts. A contributing factor was that the switches were an add-on feature, which was easily knocked out of calibration. These problems were being corrected by including valves on the locked valve program with valves being maintained in position by chains and locks. Specific locks and keys will be maintained for fire protection valves. The licensee reviewed the valves to assure that those important to safety were included in this effort. Some valves had been added to or deleted from the list based on the review.

2.6 10 CFR 50.59 Safety Evaluations

The majority of the fire protection program has been removed from the Technical Specification. This allows changes to be made to the fire protection program by performing a 10 CFR 50.59 safety evaluation. The inspector reviewed 10 CFR 50.59 safety evaluations issued for program changes for 1992. All of the changes were appropriate and were not detrimental to fire protection safety. Some surveillance cycles had been extended based on industry data and failure rates. The safety evaluations that delayed performing full flow testing of the fire main system for six months were based on preventing zebra mussels from entering the fire protection systems, and to give the licensee adequate time to make corrective actions.

The plant is currently dealing with a bio-fouling problem, zebra mussel infestation, in its intake water. Zebra mussels were found last summer on screens in the intake structure. Notable efforts were being made to prevent zebra mussels from entering the fire main systems and potentially making the fire protection systems inoperable. Full flow surveillances of the fire protection system were suspended for six months to permit modifications to the systems. Hypochlorite is being injected into the service water system, which connects to the keep fill line of the main system. In addition, thermal shock treatment is also being used to kill the mussels. A modification is planned for an injection system into the fire main system. Strainer checks indicate that the zebra mussels have not entered the fire main system. The licensee has increased the surveillance frequency for strainers. The concentration of chemicals will be monitored in the fire main system following the full flow tests to ensure that the system is maintained zebra mussel free.

2.7 Audits of Fire Protection Activities

The inspector reviewed the following audits of fire protection activities: Quality Assurance/Nuclear Safety Audit Report Number 12-91-I, January 17 through 30, 1991; Quality Assurance/Nuclear Safety Audit Report Number 12-92-I, January 27 through 31, 1992; and Offsite Quality Verification Audit Report Number 12-93-I, December 14 through 18, 1992.

Preparation for the audits was good. The audit reports were brief and did not indicate the amount of reviews that had been performed in the fire protection area. The audits had adequate detail to detect most program problems. The licensee had taken timely corrective actions for those fire protection deficiencies that were identified during the audits. The audits met regulatory requirements.

In general, the audits were more compliance based rather than being performance based. The licensee utilized a repetitive check list approach to auditing. The check lists indicated that activities listed had been reviewed in detail; however, this continued approach could contribute to missing deficiencies year after year. For example, problems with the DFP and Unit 1 yard loop reliability, which are discussed in Paragraph 2.3, were not discussed in the audits.

3. Exit Interview

The inspector met with licensee representatives (denoted in Paragraph 1) on February 22, 1993, and summarized the scope and findings of the inspection. The informational content of the inspection report was discussed with regard to documents reviewed during the inspection. The licensee did not identify any of the documents as proprietary.

TAB 19

May 20, 1996

Mr. J. S. Perry
Site Vice President
Dresden Station
Commonwealth Edison Company
6500 North Dresden Road
Morris, IL 60450

SUBJECT: NRC INTEGRATED INSPECTION REPORT 50-010/96002, 50-237/96002, AND 50-249/96002 AND NOTICE OF VIOLATION

Dear Mr. Perry:

This refers to the inspection conducted on February 14, 1996, through March 29, 1996, at the Dresden Nuclear facility. The purpose of the inspection was to determine whether activities authorized by the license were conducted safely and in accordance with NRC requirements. During this period, routine resident inspections and special planned inspections of the Fire Protection Program and the Emergency Preparedness Program were performed. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

During this inspection, several examples of ineffective correction actions were identified. The significant weaknesses in the use of system checklists and in the locked valve program, identified by the NRC, were the result of ineffective corrective actions. These examples are of concern because of the large scope of the identified problems, the multiple opportunities for your staff to identify these problems prior to the NRC, and because corrective actions to previous violations were unable to prevent recurrence. Both of these issues are unresolved in this report because your initial investigations and corrective actions were still in progress. Additionally, we are concerned about two violations of NRC requirements. In one violation, ineffective corrective actions from previous equipment failures resulted in inoperable safety equipment. In the other violation, plant procedures were not followed during testing of emergency equipment.

These violations are cited in the enclosed Notice of Violation, and the circumstances surrounding the violations are described in detail in the enclosed report. Please note that you are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response will be placed in the NRC Public Document Room (PDR).

Sincerely,

Original Signed by B. Jorgensen for

P. L. Hiland, Chief
Reactor Projects Branch 1

Docket Nos. 50-10; 50-237; 50-249

Enclosures:
1. Notice of Violations
2. Inspection Report

cc w/encl: J. C. Brons, Vice President, Nuclear Support
H. W. Keiser, Chief Nuclear Operating Officer
T. Nauman, Station Manager Unit 1
M. Heffley, Station Manager Units 2 and 3
F. Spangenberg, Regulatory Assurance Manager
D. Farrar, Nuclear Regulatory Services Manager
Richard Hubbard
Nathan Schloss, Economist Office of the Attorney General
State Liaison Officer
Chairman, Illinois Commerce Commission
Document Control Desk-Licensing

NOTICE OF VIOLATION

Commonwealth Edison Company
Dresden Station
Units 2 and 3

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

During an NRC inspection conducted on February 14, 1996, through March 29, 1996, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, the violations are listed below:

2. Dresden Technical Specification 6.2.A required, in part, that written procedures shall be implemented covering the activities referenced in Appendix A to Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2, February 1978. The operation of AC and DC emergency power systems was referenced in Appendix A to Regulatory Guide 1.33.

   A. Dresden Technical Surveillance (DTS) 6600-2-02, "Diesel Generator Fuel Consumption Test," steps I.2 and I.4, required the generator load to be maintained at 2600 kW during the test.

      Contrary to the above, on February 16, 1996, generator load varied between 2516 kW and 2600 kW during the performance of procedure DTS 6600-2-02.

   B. Dresden Engineering Surveillance, (DES) 4153-04, "Emergency Lighting Discharge Test," Revision 0, dated January 15, 1993, required that battery powered emergency lighting units needed for operation of safe shutdown equipment and in access and egress routes, as required by 10 CFR Part 50, Appendix R, shall be demonstrated by an 8-hour discharge test.

      Contrary to the above, during 1994 and 1995, 47 emergency lighting units required by 10 CFR Part 50, Appendix R were not discharge-tested for 8 hours as required by procedure DES 4153-04.

   This is a Severity Level IV violation (Supplement I). (50-237;249/96002-05).

2. Criterion XVI of Appendix B to 10 CFR Part 50 states, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and

corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

A. Contrary to the above, the licensee failed to identify and take prompt corrective actions for multiple 4 kV breaker problems which occurred since 1989. In addition, the corrective actions taken to

prevent recurrence for a similar violation issued in 1989 were not effective.

B. Contrary to the above, the licensee failed to identify and take prompt corrective actions for Containment Cooling Service Water (CCSW) foreign material problems which occurred since 1994. This resulted in the failure of the "2A" CCSW pump in March 1996.

This is a Severity Level IV violation (Supplement I). (50-237;249/96002-06)

Pursuant to the provisions of 10 CFR 2.201, ComEd is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with a copy to the Regional Administrator, Region III, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued to show cause why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Dated at Lisle, Illinois
this 20th day of May 1996

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos: 50-10; 50-237; 50-249
License Nos: DPR-2; DPR-19; DPR-25

Report No: 50-010/96002; 50-237/96002; 50-249/96002

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: February 14 through March 29, 1996

Inspectors: C. Vanderniet, Senior Resident Inspector
J. Hansen, Resident Inspector
D. Hills, Regional Inspector
R. Jickling, Regional Inspector
J. Maynen, Reactor Engineer
D. Roth, Resident Inspector
D. Schrum, Regional Inspector
C. Settles, Inspector, Illinois Department of Nuclear Safety
T. Tella, Regional Inspector

Original Signed by B. Jorgensen for

Approved By: P. L. Hiland, Chief
Reactor Projects Branch 1

88369-Ø97-128

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-10; 50-237; 50-249
License Nos:	DPR-2; DPR-19; DPR-25
Report No:	50-010/96002; 50-237/96002; 50-249/96002
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:	February 14 through March 29, 1996
Inspectors:	C. Vanderniet, Senior Resident Inspector J. Hansen, Resident Inspector D. Hills, Regional Inspector R. Jickling, Regional Inspector J. Maynen, Reactor Engineer D. Roth, Resident Inspector D. Schrum, Regional Inspector C. Settles, Inspector, Illinois Department of Nuclear Safety T. Tella, Regional Inspector

Approved By: for P. L. Hiland, Chief
Reactor Projects Branch 1

FOR INFORMATION ONLY

EXECUTIVE SUMMARY

Dresden Nuclear Station Units 1, 2 and 3
NRC Inspection Report 50-10/96002; 50-237/96002; 50-249/96002

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 7-week period of resident inspection; in addition, it includes the results of announced inspections by regional personnel in the areas of fire protection, emergency preparedness, and radiation protection.

Operations

- In general, the conduct of operations within the control room has been professional with good demeanor and communication exhibited. Concerns were raised, however, with the use of an inadequate operator aid (Section O1.2), the potential use of pen cartridges to jam feedwater heater controllers (Section O4.2) and improper operator response to an expected half scram (Section O4.3).

- Several concerns were raised with operation activities outside of the control room during this reporting period. In particular, significant problems were identified with the licensee's electrical and valve checklist and the locked valve program (Sections O3.1 and O3.2). The inspectors also identified a violation of procedure during emergency diesel generator surveillance (Section O4.1).

- While preforming the final drywell closeout the inspector identified numerous deficiencies including an unauthorized modification, loose fibrous insulation, a chainfall and straps still in place on a feedwater line, and screws missing from junction boxes (Section O2.1).

Maintenance

- Maintenance of 4kV circuit breakers was identified as a problem and was cited as an example of a violation for ineffective corrective actions (Section M2.1).

- Continued problems with foreign material interfering with the operation of the Containment Cooling Service Water system were identified and were also cited as an example of a violation for ineffective corrective actions (Section M4.1).

- Numerous examples of problems with the skill of the craft were identified by inspectors and discussed with licensee management
  (Section M4.2).

Engineering

- Several known Updated Final Safety Analysis Report (UFSAR) deviations and other licensing document discrepancies were allowed to exist for long periods of time due to inadequate emphasis on plant design and licensing basis. However, the licensee's additional emphasis on resolving both the old and the more recently identified discrepancies has resulted in subsequent changes to the plant design and administrative controls (Section E4.2).

- The licensee performed a review of the large engineering backlog to categorize the items according to safety significance and potential plant impact. The inspectors had no immediate concerns with the licensee's prioritization and resolution of these specific engineering requests (Section E4.3).

- Several items of compliance and noncompliance with the UFSAR were identified and documented (Sections U1 and U2).

Plant Support

- Briefs given to personnel performing work in high radiation and high contamination areas were thorough. Radiation protection personnel continued to maintain strict control of material entering and leaving the radiological protected area (Section R1.1).

- The overall operational status of the emergency preparedness program was good. Response facilities and equipment were adequately maintained and in an operational state of readiness (Sections P2.1 and P2.2). Audits and surveillance of the program satisfied the requirements of 10 CFR 50.54(t) (Section P7.1). Management support for the program was good and key emergency response personnel possessed a good knowledge of emergency responsibilities and procedures (Sections P5.1 and P6.1).

- Overall, the fire protection program was effective at meeting its safety objectives. Most fire protection problems were identified and substantial progress was being made to correct those problems. Fire protection program strengths included control of transient combustibles, a low number of fires during the past 3 years, and a low number of impairments requiring a fire watch (Section F1.1). In general, emergency lights were in good condition, however, a violation was identified for not testing emergency lights for the required 8 hours (Section F2.1). Also, poly-vinyl chloride (PVC) pipe usage was not well controlled in the plant (Section F1.2).

Report Details

Summary of Plant Status

Unit 2 remained in cold shutdown as refueling outage D2R14 continued throughout this inspection report period. Licensee efforts have focused on the restoration of components and systems in preparation for returning the unit to service. Work in progress includes system lineups, post-modification testing, and completion of a "fast cruise" program.

Unit 3 continued to operate at full power throughout this reporting period, except for short periods of power reduction for planned surveillance. The licensee also began a pre-coastdown to allow for the final cycle rod pull scheduled for the end of April 1996.

I. Operations

O1 Conduct of Operations (71707)

O1.1 General Comments

Using Inspection Procedures 71707 and 71711, the inspectors conducted frequent reviews of ongoing plant operations. In general, the inspectors found operations inside the control room to be conducted in a professional manner with good decorum and communication practices evident. However, conduct of operations outside the control room lacked the same adherence to station standards and management expectations. Specific concerns included the poor control and execution of system checklists and the station's locked valve program.

O1.2 Incorrect Operator Aid Results in Reactor Level Problem

On March 15, the cycling of the High Pressure Coolant Injection (HPCI) steam admission valves (2-2301-4 and 2-2301-5) caused an unexpected reactor vessel level decrease of about 3 inches. At the time of the unexpected level drop, operators were using an operator aid to correct the wide range reactor vessel level indication based on reactor pressure. Using the aid, operators had determined that level was about 4 inches below the HPCI steam line. Actual level was higher than indicated due to a ± 11 inch uncertainty in the wide range level instrumentation. The licensee's corrective action was to update the operator aid by adding a caution about the instrument uncertainty. This event demonstrated a weakness in the control of operator aids.

O2 Operational Status of Facilities and Equipment (71711)

O2.1 Inadequate Drywell Closure Inspection by the Licensee

The inspectors identified many deficiencies during the initial Unit 2 drywell closure inspection. The most significant items identified included: an uncontrolled modification; installation of loose, fibrous insulation; an under-tension chainfall around a main feedwater line; and numerous junction box covers missing screws with several covers ajar. Prior to the inspectors' tour, several members of the facility staff including management and Site Quality Verification (SQV) personnel had been in the drywell and had identified deficiencies. However, the inspections were inadequate due to a lack of a clear understanding of licensee management's expectations for a final drywell closeout inspection.

Additional efforts were expended by the licensee to correct the identified deficiencies and perform a more thorough drywell closeout. Several discussions with senior licensee management were held to communicate concerns with the implementation of management's expectations and the effectiveness of the SQV organization.

The potential uncontrolled modification consisted of four support plates attached to the drywell upper level grating by wire cables. The panels were used to hold removable inspection panels in place around the reactor vessel feedwater nozzles. The "modification" had been in place for several years. Based on a 10 CFR 50.59 review, the licensee concluded there was no unreviewed safety question and initiated Document Change Request 960028 to incorporate the identified supports into station structural drawings.

Regarding the fibrous insulation material, the licensee's response to NRC Bulletin 93-02, "Debris Plugging of Emergency Core Cooling Suction Strainers," was to remove all loose fibrous insulation from both drywells and implement administrative controls to provide assurance that any such material used during an outage would be removed during the drywell closeout inspections. The licensee was conducting further investigation to determine how the material got into the drywell and to assess the impact of such material in the emergency core cooling system (ECCS) strainers.

Numerous junction and cable pull boxes were also identified as missing several cover screws. Additionally, a junction box labeled environmentally qualified on a reactor water clean up system isolation valve was discovered with only one screw in the cover and the cover ajar, exposing the interior of the box. The Electrical Maintenance Department (EMD) responded by putting about 10 pounds of screws into junction box covers in the drywell. The licensee was asked if any of those boxes were similarly marked environmentally qualified and what was the impact of not having adequate closure for these boxes. Further review by the licensee also has been necessary on this issue.

The chainfall was removed from the drywell along with several bags of additional material. Due to the additional reviews and evaluations that were still on-going this issue will be tracked as a single Unresolved Item pending the completion of the licensee's corrective actions (50-237/96002-01).

O3 Operations Procedures and Documentation (71707)

O3.1 Checklist Verification Identified Plant Configuration Problems

During a table-top review, the inspectors identified several problems with completed system checklist documentation, control, and execution. A licensee SQV auditor independently identified similar problems. These issues were discussed with the licensee and two independent checklist reviews were initiated to resolve the problems.

When these audits were complete, the inspectors assessed the reviews by walking down the outside-of-the-drywell parts of the checklist for the "Unit 2 Standby Liquid Control System," Dresden Operations Procedure (DOP) 1100-M1. During the walkdown, the inspectors identified a valve out of its required position, two valves missing from the checklist, and discrepancies within the checklist which had not been recorded on the checklist discrepancy-resolution sheet. Although the standby liquid control system remained operable, the errors demonstrated that the checklists execution and reviews were inadequate and not in accordance with plant procedures.

The licensee responded to these new findings by staffing a 50-person, multi-discipline team to reverify 85 Unit 2 system checklists. The licensee also decided that the Unit 2 startup would not occur until the checklist discrepancies were addressed and resolutions specified.

The results of the licensee's re-verification efforts will be tracked as an Unresolved Item pending the checklist review completion (50-237;249/96002-02).

O3.2 Locked Valve Program Inspection Identified Plant Configuration Problems

On March 8, the inspectors determined that some containment isolation valves which were identified as locked closed by the Updated Final Safety Analysis Report (UFSAR) Section 6.2.4.2.1, and Dresden Administrative Procedure (DAP) 7-14, "Control and Criteria for Locked Equipment and Valves," were not locked. More than 30 valves listed in UFSAR Table 6.2-10 were not included in the licensee's Unit 2 locked valve program implementation procedures (DOP 0040-M2 and M4). Also, there were several discrepancies in the UFSAR such as omitted valves and valves with incorrect penetration listings. After discussions with the licensee, operations and engineering personnel completed a review of containment isolation valve requirements and implementation, and identified several significant discrepancies including:

- Four valves committed to being locked closed in the Systematic Evaluation Program that were not in the locked valve procedure.

- Several locked valves were missing placards, identifying locked open or closed, which were required by a commitment to a violation from February 1, 1984.

- The lock and chain were missing from the Unit 2 shutdown cooling inlet header "A" outboard drain valve (2-101-46A).

- A locked valve, operated during a surveillance, was repositioned with no independent verification of the valve's final position.

- Twelve valves listed in the UFSAR did not appear on the locked valve checklist for Unit 3.

- Two containment isolation valves installed by "exempt changes"
E-12-2-95-232 and 233 were not identified as locked valves although the valves should have been added to the locked valve procedure by the modification process. (An "exempt change" is similar to a modification.)

As a result of the findings, the licensee developed a new technical position on locked containment isolation valves. This position required the correction of identified procedure errors, the deletion of 60 valves from the UFSAR tables, and the addition of 70 valves to the UFSAR tables. A walkdown of the valves was completed by the licensee with no containment isolation valves found out of position. The locked valve procedures were revised to incorporate the identified deficiencies and changes. The checklist team (see Section O3.1) is re-verifying locked valves during checklist execution.

The inadequacy of the licensee's locked valve program has been a longstanding issue. Numerous Corrective Action Requests, Performance Improvement Forms (PIFs), and violations have been issued on this subject over the last 2 years. However, remedial actions taken have never corrected the full extent of the problem. Final resolution of the corrective actions for these findings and the results of the licensee's locked valve verifications will be tracked as an Unresolved Item (50-237;249/96002-03).

O3.3 Atmospheric Containment Atmosphere Dilution (ACAD) Operating and Surveillance Procedures' Bands Differ

The inspectors noted that the ACAD system air receiver operating pressure band was being maintained at 44 to 57 psig, which was above the band in DOP 2500-01, "ACAD Dilution Subsystem Operation" (41 to 52 psig). Dresden Operating Surveillance (DOS) 2500-01, "ACAD Compressor Surveillance" and Dresden Administrative Technical Requirements (DATR) Section 3/4.5 both listed a pressure band of 44 to 57 psig. In order to resolve this issue, the licensee planned to revise the ACAD procedures to reflect the installation of Nitrogen Containment Atmosphere Dilution (NCAD) system on Unit 2 and to address the UFSAR discrepancies discussed in Section U2.4 of this report. (Note that when NCAD is installed in Unit 2, the operability of Unit 2 ACAD is no longer required.) This item will be tracked as an Inspector Followup Item (50-237;249/96002-04) pending review of these changes.

O4 Operator Knowledge and Performance (71707)

O4.1 Failure to Follow Procedures During Unit 3 Emergency Diesel Generator (EDG) Surveillance

On February 16, the inspectors observed field and control room performance of two Unit 3 EDG surveillance tests. At that time, "Diesel Generator Surveillance Tests" (DOS 6600-01), and Dresden Technical Surveillance (DTS) 6600-2-02, "Diesel Generator Fuel Consumption Test," were being run simultaneously. While DOS 6600-01 step I.12.c.(5) required the diesel load be maintained between 2500 and 2600 kW, DTS 6600-2 steps I.2 and I.4 required the generator load to be maintained at 2600 kilowatt (kW) during the test. The inspectors observed that local generator load was 2520 kW. Discussions indicated that the control room operators were not aware of the additional loading restraints of the DTS and were operating the EDG in accordance with the DOS. The inspectors informed the system engineer and Unit Supervisor of the discrepancies. A review of the test data showed that generator load varied between 2516 kW and 2600 kW during the test. This band was too low to satisfy the DTS requirements. Failure to follow procedures was an example of a violation of Technical Specification 6.2.A (50-237;249/96002-05A).

O4.2 Potential Improper Control of Feedwater Heater Controllers

On March 15, the inspector questioned the purpose of the blue strip-chart ink cartridges that were staged by Unit 3 feedwater heater controllers. The Unit 3 Nuclear Station Operators (NSOs) and the Unit Supervisor both stated that the cartridges were to "jam the feedwater heater controllers in pull-to-stop." This practice freed the operator's hands during a loss of feedwater heaters. (Note that the controllers were designed to spring return to the automatic control position when not being held in pull-to-stop.) The inspector immediately brought this to the attention of the Shift Operations Supervisor, who stated that use of the jams was not acceptable and the jams were immediately removed.

The consequence of using jams was given by the "CAUTION" in Dresden Operating Abnormal (DOA 3500-02), "Loss of Feedwater Heaters,"
Revision 9, which stated, "By stopping the Feedwater Heater Extraction Steam Valves from closing upon a high level signal in the feedwater heater, the possibility of water induction into the turbine rises. IF the valves are stopped from closing, THEN the operator should continuously monitor the condensate level in the heaters with the high level indication. The valve should be allowed to close if the level reaches the high stop on the control room indicator." The use of jams would complicate compliance with this caution statement.

The use of jams was not permitted by any station procedure and, if used, would have constituted an unanalyzed temporary alteration. Procedure DAP 07-02 E.13.e stated, "A controller may be placed in manual whenever the judgement of the operator dictates that continued automatic operation is unsafe or may cause unnecessary transients." While the inspectors had not observed the jams being used, the inspectors were concerned that the practice of staging control jams demonstrated a willingness to work outside of procedures to keep the plant at power.

O4.3 Inappropriate Response to Expected Alarm Results in Unit 2 Scram

On March 27, with the Unit 2 mode switch in refueling and all rods inserted, an expected half-scram signal was received during surveillance testing. Rather than acknowledging the alarms, the NSO responded inappropriately by immediately pushing both scram pushbuttons, which initiated a manual scram. All plant equipment responded as designed and the unit was placed in a stable condition. The operator was removed from panel operation in accordance with the normal investigative process and a prompt investigation initiated. The licensee's investigation showed that the NSO had briefed the Unit Supervisor of the anticipated half-scram. However, when the alarm actuated, the NSO reacted too quickly and scrammed the unit. The NSO was counseled concerning the event and returned to control panel operations. The licensee's immediate corrective actions appeared thorough and adequate to prevent recurrence. The inspectors planned to assess the effectiveness of the long term corrective actions when the Licensee Event Report (LERs) is issued.

O8 Miscellaneous Operations Issues (92901)

O8.1 <u>(Closed) Unresolved Item 50-237/95015-08</u>: On February 5, 1996, Unit 2 experienced an unexpected 100 psig discharge of all the Hydraulic Control Unit accumulators. The licensee determined the cause to be a sudden release of a freeze-seal. The inspector reviewed the root cause investigation report and had no further questions and closed the item.

O8.2 <u>(Closed) Unresolved Item 50-237;249/95014-01</u> On November 27 and 29, 1995, the facility experienced trips of Unit 2 and Unit 3 fuel pool cooling water pumps respectively. The licensee has determined that the trips were the result of unexpected actuation of the fuel pool filter high pressure switch. The pumps have a discharge pressure of about 185 psig and the pressure switches have setpoints of 150 psig. Due to piping losses, however, the systems operate very close to the trip setpoint. Therefore, any fluctuation in the system could result in trips of the pumps. This was particularly true when returning a filter to service. Corrective actions included recalibration of the pressure switches and revision to the system operating procedures. The inspector reviewed the root cause investigation report and had no further questions.

II. Maintenance

M1 Conduct of Maintenance (62703)

M1.1 General Comments

The inspectors found that most maintenance activities observed were completed satisfactorily, however, inadequate resolution of previously identified problems continued to exist. The inspectors identified one violation concerning ineffective corrective actions regarding 4kV breaker maintenance and containment cooling service water (CCSW) foreign material exclusion (FME) controls. These problems had long histories of occurrences yet continued to remain a challenge to plant operations. Also, past and present skill of the craft problems have been evident during the inspection period and have resulted in rework.

M2 Maintenance Material Condition of Facility and Equipment

M2.1 Inadequate Corrective Action of 4kV Breaker Maintenance

The 4kV breakers used at the station were known to have problems for many years. In 1989, the licensee was cited for failure to identify root causes for 4kV breaker failures and to take prompt corrective actions. The licensee's corrective actions included an accelerated preventive maintenance schedule for the 4kV breakers and additional direction from system engineering regarding performance of root cause analysis.

The inspectors reviewed the 4kV breakers work history from 1989 through 1996. Several problems were identified during this period with 4kV breakers including four LERs and several PIFs.

- Inadvertent auto start of the Unit 2/3 EDG due to damage to a breaker linkage. (LER 2-93-06)

- Failure of an EDG output breaker to close due to a bent linkage on a 4kV main feed breaker. (LER 2-93-012)

  The root cause determination and corrective actions for these failures were not effective.

- A PIF (TDF-2-94-M625) was issued in 1994 indicating breaker linkage problems on four safety-related busses.

  Since this was a low priority PIF, no further investigation was performed to identify the root causes. In addition, the recommendations made to correct the linkage problems were not followed.

- Inadvertent auto closure of the EDG output breaker that caused the EDG to "motor." (LER 2-95-009)

  This was attributed to a failure of the Close Latch Monitoring Switch coupled with linkage binding attributed to inadequate maintenance. The corrective actions taken for this LER had not included any actions to prevent future linkage problems.

- Twelve PIFs were generated on problems with 4kV breakers during January 1996.

- Damaged linkage on the inter-tie 4kV breaker discovered during a surveillance test when the Unit 2 EDG output breaker failed to close. (LER 2-96-001)

  The root causes for the linkage problems were not identified in the LER.

The above examples indicated that the root cause evaluations and corrective actions for the 4kV breaker linkage problems during the
1989-96 period were inadequate. As stated above, the licensee's 1989 corrective actions included system engineering to provide root cause analyses for the breaker problems. However, the corrective actions taken were not effective in preventing recurrence of the breaker problems.

The licensee's continued failure to identify root causes for 4kV breaker problems over several years and failure to take prompt corrective actions was an example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI (50-237;249/96002-06A).

During January 1996, the licensee upgraded the breaker investigation and selected a 10 member team to investigate the adverse trends related to 4kV breaker performance. The licensee's team concluded that the primary root cause for the breaker problems was a lack of technical documentation. This report also stated that other contributing causes were:

- Inadequate previous event root cause determination and corrective actions;
- Too many tasks assigned to the system engineer (management deficiency);

- Change-related documents not developed or not revised.

However, the inspectors noted that even though the licensee concluded that the lack of technical documentation was the primary root cause for the breaker problems, it appeared that no efforts were initiated to evaluate whether the lack of technical documentation affected any other areas of the plant. The inspectors planned to evaluate the licensee's corrective actions when the response to the violation was issued.

M4 Maintenance Staff Knowledge and Performance

M4.1 Inadequate Corrective Actions Concerning Foreign Material Exclusion (FME) Results in Containment Cooling Service Water (CCSW) Inoperability

On March 1, the 2A CCSW pump was started to support a visual inspection of the piping. Normal flow was established at about 3500 gpm when the local operator reported the pump sounded "bad," and the pump was secured. The pump was restarted with maintenance and engineering personnel present but flow only came up to about 2200 gpm at 100 psig (normal discharge pressure was about 185 psig). Initial investigation identified a small "cloth-like" rag that was lodged in the pump impeller. Corrective actions taken to ensure the CCSW bay was free of foreign material included a diver inspection of the suction bay and the running of all remaining Unit 2 and 3 CCSW pumps individually to ensure flow met surveillance requirements.

Foreign material in the CCSW system has been a recurring problem at the facility and recent examples include:

- On November 28, 1994, two pieces of wood were discovered in 3A CCSW pump during a pump run. Corrective actions included stating the need for better control of foreign materials.

- On January 16, 1996, a loss of flow and pressure occurred in the control room during surveillance testing being conducted on the 2D CCSW pump. The local operator reported that the pump began to vibrate and sounded like it had lost suction. An investigation was performed but a root cause for this event was not identified. The pump was retested with satisfactory results and was returned to service.

- On February 22, 1996, a small slice of wood was discovered impeding the hinge on the 3D CCSW pump discharge check valve. The valve was disassembled and the wood removed.

The multiple examples of foreign material intrusion into the CCSW system demonstrated that corrective actions were ineffective in preventing repetitive occurrences. Failure to take corrective action to preclude repetition was an example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI (50-237;249/96002-06B).

M4.2 Skill of the Craft

During tours the facility with licensee management, the inspector identified numerous examples (past and current) of poor skill of the craft work. Examples of poor mechanical skill of the craft work included the following:

- Inconsistent use of flat washers on flange connections.
- Inconsistent use of lock washers.
- Use of soft flat washers under torqued bolts.
- Hanger and small piping supports not made up tightly.
- Misaligned flanges.
- Stacking flat washers under a bolt that was too long for application.
- Bolts too small for flange holes.

The identified problems were on the Unit 2 reactor feedwater pumps and the Unit 2/3 EDG. None of the examples posed an operability or safety concern and the licensee took immediate actions to explain skill of the craft expectations to the staff. Mechanical Maintenance Department (MMD) has initiated a display board in the work space which identified good and poor examples of skill of the craft. This was a positive action to communicate the expectation of management to the technicians regarding this issue.

On March 9, an incomplete and unclear electrical work package in conjunction with weak skill of the craft resulted in delayed work completion and the potential for personnel injury. Electrical maintenance personnel were performing the bridge/meggering portion of DIS 2400-02, "Post-LOCA

Containment Hydrogen and Oxygen Analyzer 18 Month Calibration and Maintenance Inspection," for the Unit 2 H_2O_2 sample pump. Work was delayed because a copy of the bridge/megger procedure was missing from the work package. Electrical maintenance personnel incorrectly attempted to perform the meggering/bridging from the breaker which was the incorrect piece of equipment. While the work package was not clear that testing should have been done at the H_2O_2 panel, the fact that the breaker was a molded case circuit breaker and did not have pump controls incorporated was not identified by EMD personnel. This not only slowed completion of the work but could have resulted in personal injury as the wrong piece of equipment was tested.

Additional examples of poor electrical skill of the craft identified during this inspection period included:

- Plugs not fully installed in a motor-operated valve torque switch housing.
- Inconsistent use of flat and lock washers on EDG generator covers.
- Screws missing from junction cable pull box covers.

Assessment of skill of the craft performance will be an ongoing part of the inspectors field observations.

III. Engineering

E1 Conduct of Engineering (37551)

E1.1 General Comments

The licensee had a history of inadequate emphasis on resolving design and licensing basis nonconforming conditions. While some improvement has occurred, weaknesses remained in this area. Specifically, the licensee had allowed several known UFSAR deviations and other licensing document discrepancies to exist for long periods of time without resolution. Safety evaluations pursuant to 10 CFR 50.59 had not been conducted or planned prior to startups from refuel outages to ensure unreviewed safety questions were not involved. In addition, the inspectors identified several previously unrecognized UFSAR deviations. Some of the deviations resulted in subsequent changes to the plant. The licensee placed additional emphasis on resolving known UFSAR deviations following the identification of the issue.

E3 Engineering Procedures and Documentation (37551)

E3.1 Some Improvements In Control of Operability Evaluations (OE); Some Weaknesses Remained

In response to untimely resolution of two OEs identified in Inspection Report 50-237;249/96005, the inspectors completed a review of the remaining open operability evaluations. This review was limited to an estimation of issue significance and corresponding licensee timeliness.

Historically, open OEs developed into a substantial backlog through inadequate attention in previous years. Operability evaluations were placed into a control room binder and action items were placed into the Nuclear Tracking System (NTS). However, there was no ownership of the program and no organized effort to track OEs as a special entity and to ensure timely closeout. This inadequate control of OEs was identified by the inspectors in October 1994 (Inspection Report 50-237/94015.)

Increased management attention has only been partially implemented. At the time of the current inspection, the licensee had taken some actions to address this concern by assigning an engineer to overview the program. In addition to the control room, OEs had been organized into individual binders kept in the engineering department. Statistics compiled by the licensee during this inspection, indicated that the number of open OEs had decreased from approximately 100 to 40 during 1995. Most of the remaining open OEs contained little more than the original and any documentation available at the time the OE was developed. Neither the binders or a computer program developed to track the OEs were very current or detailed with respect to status.

A review of all the open OEs indicated a substantial portion had been resolved but remained open for some other action such as a drawing change. The others were timely with respect to licensee actions except those noted in Section E4.1 of this report below. During the inspection, the licensee updated the status of the open OEs and increased emphasis on closeouts.

E4 Engineering Staff Knowledge and Performance (37551)

E4.1 Some Untimely Resolutions of Licensing and Design Basis Nonconforming Conditions

The inspectors identified the untimely resolution of the following three open OEs:

- Low Pressure Core Injection Corner Room Structural Steel Failure To Meet Applicable Design Margins - Discussed in Inspection Report 50-237;249/96005.
- Reactor Protection System Single Failure Vulnerability - Discussed in Inspection Report 50-237;249/96005.
- Absence of Automatic Control Room Ventilation Purge Mode.

During testing of control room exhaust ducts in November 1994, the licensee discovered that the control room ventilation system did not have the automatic purge mode that was described in the UFSAR Section 6.4.4.3. Engineering had not yet submitted a proposal to the Issues Review Board (IRB) for resolution. The licensee had not performed a 10 CFR 50.59 safety evaluation to ascertain whether this condition was an unreviewed safety question. Following discussion of the inspector's concerns, the licensee performed a safety evaluation prior to startup from the ongoing Unit 2 refuel outage and concluded that an unreviewed safety question had not existed.

Appendix A to NRC Branch Technical Position 9.5.1, "Fire Protection Requirements," (to which Dresden's Fire Hazard's Analysis was written) only required a manual capability for plants under construction or operating prior to July 1, 1976. Although an automatic purge mode had not existed, operators could manually realign the system upon detection of smoke in the control room. This deviation from the UFSAR will be tracked as an Unresolved Item (50-237;249/96002-07).

E4.2 Inadequate Emphasis on Design and Licensing Basis Nonconforming Conditions

Historical Perspective

A history of significant licensing and design basis deficiencies indicated that the licensee's previous emphasis in this area was inadequate. Examples included:

- An unreviewed safety question on long term usage of a temporary sample pump that bypassed primary containment (1990).

- Non-conservative changes from safety evaluation report calculation assumptions involving the control room habitability analysis (1992).

- An unreviewed safety question regarding changes accepted by the facility involving containment cooling service water flow (1993).

- Failure to properly evaluate changes to the Unit 1 Decommissioning Plan including failures to maintain heating, properly lay up piping, and maintain a project manager (1994).

Other less significant problems involving licensing basis and design deficiencies also occurred during this time period.

Current Perspective

Some improvement in the licensee's emphasis placed on the design and licensing basis was apparent. In particular, the UFSAR rebaseline in 1993 resulted in a much improved product. Previously, much of the licensing basis was missing from the UFSAR. The inspectors had not attempted to verify accuracy of the entire rebaselined UFSAR. However, limited use by the inspectors found substantially larger amounts of pertinent information and greater useability than its predecessor. In addition, some nonconforming conditions with the design and licensing basis were resolved in a timely manner. Timely resolution of control rod drive scram discharge header structural steel deficiencies noted in Inspection Report 50-237;249/95015 was an example.

Still, the following indications implied some continuing problems with the licensee's emphasis on the plant design and licensing basis:

- The untimely resolution of the three OEs discussed in Section E4.1 reflected inadequate emphasis during technical reviews and licensee management decisions.

- A recent unresolved item (50-010/95015-06) involved numerous discrepancies identified by the inspectors regarding Unit 1 ventilation practices, hot shop and contaminated storage on the Unit 1 turbine deck, and asbestos removal with respect to various licensing basis documents. These discrepancies had not been identified by the licensee and had not received a 10 CFR 50.59 safety evaluation.

- Other UFSAR deviations recently identified by inspectors that had not received 10 CFR 50.59 safety evaluations included:

    - Use of poly-vinyl chloride (PVC) in the plant with respect to Fire Hazards Analysis commitments to minimize PVC usage. (Also see Section F1.2 below.)
    - Emergency diesel generator fuel oil piping and condensate storage tank piping configurations that differed from plant design. (Also see Section U2.3 below.)

- Other UFSAR deviations recently identified by the inspectors which resulted in subsequent plant changes included:

    - The ACAD system was not de-energized in accordance with the UFSAR. (Also see Sections O3.3 (above) and U2.4 (below).)
    - Several required valves that were not locked contrary to Systematic Evaluation Program licensing commitments. (Also see Section O3.2 above.)

Although many UFSAR discrepancies were identified, the rebaselining effort had missed the above examples even though knowledgeable plant personnel had reviewed the UFSAR changes. Additionally, there was no requirement for actual verification against plant practices, procedures, or design.

- Approximately 49 licensee UFSAR rebaseline items had remained open since June 1994. Several constituted UFSAR deviations, needed UFSAR clarifications, or presented other licensing document discrepancies. Following more in-depth review of each, a licensee contractor had submitted proposed resolutions to the licensee during the fourth quarter 1995 and into 1996. The proposed resolutions had gone to a design engineer who had not yet acted upon them due to other priorities. There was no plan for resolution through 10 CFR 50.59 safety evaluations or other actions prior to Unit 2 startup.

- The licensee subsequently performed NTS database searches for any additional previously identified examples which had not been resolved. Several were captured through this review with the oldest dating back to 1991. This NTS item involved incorrect UFSAR containment isolation valve tables. The licensee had performed walkdowns to resolve this UFSAR deviation in 1995. However, the licensee had not yet marked up changes for a UFSAR revision or performed a 10 CFR 50.59 safety evaluation regarding the discrepancies. No such actions had been planned prior to Unit 2 startup.

- The licensee subsequently identified additional previously unidentified UFSAR deviations. These examples involved reactor water cleanup low pressure isolation setpoint and valves missing from the capped valve checklist. Both were resolved through plant changes. Another example involving reactor recirculation seal purge line containment isolation valve configuration that had not yet been resolved by the end of the inspection period.

Resolution of these additional UFSAR deviations identified by the licensee is an Unresolved Item (50-237;249/96002-08).

E4.3 <u>Additional Emphasis Placed on Resolving UFSAR Deviations</u>

The licensee performed additional reviews of the UFSAR rebaseline open items and NTS items involving UFSAR deviations and other licensing discrepancies as described above. The licensee's intent was to resolve these prior to Unit 2 startup and this effort was ongoing at the end of the inspection period.

In addition to the reviews described in Section E4.2 above, the licensee reviewed the large backlog of open engineering requests to identify significant issues needing more timely resolution. The inspectors examined the engineering requests that the licensee identified as needing more in-depth review. The inspectors had no concerns regarding the prioritization and resolution of these specific engineering requests. At the end of the inspection, the licensee expanded the reviews to additional backlog databases.

The inspectors reviewed the licensee's Issues Review Board and Business Review Committee decisions dating back to June 1995. This review was still ongoing at the end of the inspection period.

E8 Miscellaneous Engineering Issues (92902)

E8.1 <u>(Open) Unresolved Item 50-237/94003-04</u>: Licensee to rerun seismic and dead weight analyses on low pressure coolant injection piping to account for different temperature combinations and perform technical audit. The licensee responded to this item in a letter dated June 10, 1994. This issue will remain open pending review of that response.

E8.2 <u>(Open) Unresolved Item 50-010/95015-06</u>: Numerous discrepancies were identified by the inspectors regarding Unit 1 ventilation practices, hot shop and contaminated storage on the Unit 1 turbine deck, and asbestos removal with respect to various licensing basis documents. The licensee was conducting a 10 CFR 50.59 safety evaluation at the end of the inspection period. This item will remain open pending review of the safety evaluation.

IV. Plant Support

R1 Radiation Protection and Chemistry (RP&C) Controls (83726)

R1.1 <u>General Comments</u>

The inspectors observed Heightened-Level-of-Awareness briefs given to personnel performing work in high radiation and high contamination areas, such as the drywell, and found the briefs to be thorough. The inspectors also noted that radiation protection personnel continued to maintain strict control of material entering and leaving the radiological protected area.

P1 Conduct of EP Activities (82701)

P1.1 <u>Emergency Preparedness (EP) Program Review</u>

A routine inspection of the operational status of the EP program was performed in accordance with Inspection Procedures 82701 and Temporary Instruction 2515/131.

P1.2 <u>Actual Emergency Plan Activations</u>

An Unusual Event was declared at 5:15 a.m. on December 17, 1995 due to the detection of potentially flammable gases accumulating in the Rad Waste building. The Unusual Event was terminated at 11:15 a.m. when the hydrogen leak was isolated and the building had been ventilated reducing hydrogen concentration below detectable levels.

Records reviewed indicated that the classification and notifications had been made properly and in a timely manner. The documentation package for the event was detailed and complete.

P2 Status of EP Facilities, Equipment, and Resources (82701)

P2.1 <u>Emergency Response Facilities, Equipment, and Supplies</u>

Inspections were conducted of the Control Room, Technical Support Center (TSC), Operational Support Center (OSC), Emergency Operations Facility (EOF), and the Field Monitoring Team vehicles stored in the Generating Stations Emergency Plan (GSEP) barn. Facilities and equipment were in an good state of operational readiness.

Housekeeping in the OSC and the GSEP barn was discussed regarding the temporary storage of dosimetry racks in the OSC and boxes of furniture in the GSEP Barn. These temporarily stored items appeared to have no impact on the facilities function. Equipment and instruments were verified operational in the facilities and selected procedures were current and available.

P2.2 <u>Licensee Offsite Communications Capabilities (2515/131)</u>

The following is a list of the licensee's communications systems that were available to notify offsite agencies in the event of natural disasters.

- Nuclear Accident Reporting System was the licensee's primary method for offsite emergency notifications. This system used dedicated, commercial phone lines and was available in the control room, TSC, EOF, State, and local emergency operations centers.

- Commercial phone lines were available in the plant as well as onsite and offsite Emergency Response Facilities.

- Microwave communication system was available from the plant to the Load Dispatchers who were trained to contact the appropriate offsite agencies. This system used dedicated lines and was available in the control room, TSC, and EOF. Microwave used offsite power and had a battery backup in the switchyard.

- Tie Lines or 'T' Bone, the licensee's private dual ring, self healing, counter rotating, fiberoptics system could connect the control room, TSC, and EOF to offsite agencies.

- Security radio system connected Security to the Grundy County.

- Cellular phones were located in the control room, TSC, and OSC.

The communications room on the first floor of the administration building was the central point for wired telecommunications. The room was locked and key entry only. The communications room could be susceptible to an earthquake.

All telecommunication lines were buried out to ten miles and the only apparent common mode vulnerability would be a fire in the communications room or severe earthquake. All communications power sources were backed by battery and the security emergency diesel generator with the exception of microwave system and the cellular phones. The microwave tower could be susceptible to tornado or earthquake. The microwave system tower was designed to take 80 mile per hour winds with one half inch of radial ice.

Spare parts, including some radio parts and cabling, were stocked. Telephone directories list the available communications capabilities, and procedure DOP 10-14, "Loss of Communications Systems," dated May 1, 1990, was validated and available for restoring communications. Personnel were trained in procedure DOP 10-14. All communications services were contracted offsite. Based on the inspection, Temporary Instruction 2515/131 is closed.

P3 EP Procedures and Documentation (82701)

P3.1 <u>Review of Updated Safety Analysis Report Commitments</u>

The inspector reviewed UFSAR Section 13.3, Revision 01A, dated December 1995, which related to the Emergency Plan. The inspector verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

P5 Staff Training and Qualification in EP (82701)

P5.1 Training

Records indicated that training, drills, and exercises were formally critiqued. Selected EP training lesson plans were reviewed and found to be appropriately updated. A review of the most recent EP training printout dated March 18, the first quarter GSEP augmentation callout list dated February 27, and other documentation indicated a minor problem with Emergency Response Organization (ERO) qualifications of three persons. The ERO qualification issue was immediately and appropriately corrected by the EP trainer.

Interviews were conducted with key ERO personnel to determine whether they have been trained and understood their emergency responsibilities, authorities, and procedures. The interviews included a TSC Station Director, Acting Station Director, and a control room/TSC Communicator. Personnel interviewed responded well to questions regarding their emergency responsibilities and were familiar with emergency actions and procedures.

P6 EP Organization and Administration (82701)

P6.1 Organization and Management Control

Organizational report paths have changed and the EP Coordinator now reports to the Regulatory Assurance Manager (since February 1996), who in turn reports to the Acting Site Vice President. Interviews were conducted with the EP and training staffs and management to determine any changes to the organization, management, or program and impact on the program effectiveness. These changes resulted in a relatively short, effective reporting path.

The site EP Coordinator resigned from the company effective March 1, and a new coordinator was not scheduled to fill the position until April 12. Corporate EP provided personnel daily to the plant to maintain and support the program as needed.

P7 Quality Assurance in EP Activities (82701)

P7.1 Audits

The licensee's 1995 annual audit of the EP program (Audit QAA 12-95-05), dated May 8-12, 1995, was reviewed and found to be of good scope and depth, satisfying the requirements of 10 CFR 50.54(t). The licensee provided information on how to obtain the section of the audit pertaining to the adequacy of offsite interface at the annual Offsite Agency Meeting on October 26, 1995. The five person audit team included another licensee's EP Coordinator which added to the team's expertise.

The audit identified three deficiencies which were related to controlled documents, callout list phone numbers, and Emergency Response Facility equipment surveillance. Corrective actions included immediate correction of all identified problems and long term actions that included changing the document control process for EP, revision of the procedure for obtaining phone numbers, and incorporation of an annual perishable equipment rotation in the surveillance procedures. The licensee's immediate corrective actions were effective and planned long term actions appeared adequate to prevent recurrence.

The licensee completed an effective self-assessment of the EP program was completed on March 1, 1996. Corporate EP personnel and another ComEd station's EP trainer were involved in this effort. Items identified by the review team included: old tape and dead batteries not identified during surveillance; temporary storage of materials in two emergency facilities; and training records not easily being retrievable. Recommendations included: review of storage use in emergency facilities to determine any negative impact on emergency readiness; review of surveillance procedures to assure their adequacy; review of the Corrective Action Request for changing the document control process for EP; and improvement of the filing system for EP training records.

P8 Miscellaneous Emergency Preparedness Issues (92904)

P8.1 <u>(Closed) Inspection Followup Item 50-237;249/95002-06)</u>: Information regarding NRC and Department of Energy emergency incident response was not included in EP training lessons plans. Review of current lesson plans and interviews with key emergency response organization personnel indicated that NRC and Department of Energy incident response information was included in specific lesson plans and that key personnel had knowledge of this. This item is closed.

F1 Control of Fire Protection Activities (64704)

F1.1 Observation of Plant Areas

The inspector toured the reactor, turbine, and screen house building areas to observe the adequacy and control of combustibles, fire doors, hose stations, detection equipment, extinguishers, sprinkler systems, emergency lights, and housekeeping. Control of combustibles in the plant was good. This included having very few transient combustibles in the plant for an outage. Flammable and combustible liquids and lubricants were stored in fireproof cabinets and flammable liquids were stored in safety cans. Wood and plastics used in the plant were fire resistant.

The license had a low number of fires during the last 3 years with only a few fires involving hot work. This was a good indicator of effective hot work controls.

The majority of fire protection equipment material condition was good. Most fire doors in the plant were in excellent condition which included self-closure and latching mechanisms. A new diesel fire pump had been installed which increased the reliability of the fire suppression system. In addition, most fire protection problems were identified and assessed with appropriate corrective actions taken. The majority of items on the fire protection work request backlog were not significant. The licensee had a backlog of sprinklers and valves to be repaired but these items did not detract significantly from the reliability of the suppression systems. Extinguishers had been inspected and had a current inspection date. Fire fighting gear was in good condition and well organized. There was a low number of fire protection impairments requiring a fire watch.

Zebra mussels were adequately controlled and represented no threat to the fire protection systems at this time.

The fire protection staff was experienced, knowledgeable, and proactive in dealing with fire protection problems. The corporate fire protection staff were supporting the plant in identifying and taking corrective actions for site fire protection problems, which included a training session with the EMD staff for emergency lighting issues.

F1.2 Polyvinyl Chloride (PVC)

The inspectors identified that PVC usage in the plant was not well controlled. A UFSAR and Fire Protection Report commitment required the minimization of PVC use in the plant. A 1986 control rod drive modification installed PVC drain piping. No 10 CFR 50.59 evaluation was performed, and the increased combustible fire loading was not added to the Fire Hazards Analysis (FHA) for this area. The modification had been performed by a work request and not by the modification process. The plant staff had numerous opportunities to identify this problem in the plant. The licensee completed a 10 CFR 50.59 evaluation during the inspection period and determined that no unreviewed safety question existed.

Additionally, the licensee committed to identify other unevaluated uses of PVC in the plant and to specifically evaluate PVC usage during the modification process. Also, the PVC fire loading will be added to the FHA. The PVC problem was an example of the licensee not following the UFSAR commitments. A second example of the FHA not being updated, for a change in plant conditions, was for the construction of a concrete building on the turbine deck. This will also be included in the next update to the FHA. Resolution of this deviation from the UFSAR and Fire Protection Report commitment will be tracked as an Unresolved Item (50-237;249/96002-09).

F2 Status of Fire Protection Facilities and Equipment (64704)

F2.1 Emergency Lighting

The maintenance staff were not following procedures during the implementation of Dresden Engineering Surveillance (DES 4153-04), "Emergency Lighting Discharge Test," which required emergency lights to be discharge tested for 8 hours. A review of emergency lighting 8-hour discharge surveillance performed in 1994 indicated that 26 emergency lights had not been discharge tested for 8 hours. This same problem was identified for 21 emergency lights during a review of the 1995 surveillance. Technical Specification 6.2.A required that written procedures be established, implemented, and maintained for activities recommended in Regulatory Guide 1.33, Rev. 2, Appendix A and for Fire Protection Program implementation. The failure to follow procedures was an example of a violation of Technical Specification 6.2.A (50-237;249/96002-05B).

During the inspection, the emergency lights that did not have an 8-hour discharge test were retested. The licensee was conducting an investigation to assess why the maintenance staff had not performed the surveillance for 8 hours. In addition, emergency lighting training sessions were conducted for the EMD staff. Also, the corporate fire protection staff requested a review of surveillances at the other licensee sites to verify that this was not a problem at the other facilities.

In general, emergency lights were in good condition. Most emergency lighting problems had been identified by the licensee in November 1995 and had been corrected. A good reliability rate for emergency lights was noted during the review of surveillance. However, additional minor emergency lighting problems were identified during plant tours. The inspector noted that a backup emergency light for an emergency light being discharge tested was not operable. This problem should have been identified by the person who placed the backup emergency light in the plant. An inspector identified an emergency light that had been blocked by a plant modification. Additionally, emergency lighting lamps were noted as dirty or had paint overspray. Also, several emergency lighting lamps were not properly aimed. For example, emergency light number 240 was not aimed at Motor Control Center 28-2 panel for operating safe shutdown equipment. The fire protection staff had not noted this problem even though the area was toured by fire protection personnel several times during the inspection. The licensee also stated that some of the data for correctly aiming the emergency lights was not accurate.

The licensee temporarily moved the blocked emergency light with plans to permanently relocate this emergency light to a new location. In addition, a work request had been written to correctly aim emergency lights. Also, a procedure change was made to ensure that emergency lights lamps will be cleaned. The completion of the corrective actions for the identified emergency lighting problems is an Inspector Followup Item (50-237;249/96002-10).

F4 Fire Protection Staff Knowledge and Performance (64704)

F4.1 Fire Brigade

A review of fire brigade training and qualification records indicated that site requirements had been met by all brigade members who were listed as qualified.

The inspector observed fire brigade drills in the reactor and the turbine buildings. Five fire brigade members responded in a timely manner to the simulated fires with appropriate fire fighting gear and completed dressing for entering the space. The fire brigade appropriately used the pre-fire plans to identify the risks in the areas and simulated isolating the electrical equipment. The first fire brigade drill included substantial coaching of the fire brigade by a member of the fire protection staff. No assessment could be made of the brigade's performance as a result of the coaching. In addition, a critical evaluation of comments made during the critique stifled effective feedback of drill problems from brigade members. Also, a oxygen breathing apparatus regulator problem during this drill was a significant concern. This problem had been noted in the critique records of previous fire brigade drills. The licensee stated that new regulators had been funded for purchase during 1996. A second fire brigade drill, held as a result of the coaching issue, was assessed as satisfactory with a good critique to identify problems.

Two examples were noted of the pre-fire plans not being updated for fire brigade use. An electrical system that was not identified in the pre-fire plans contributed to a delay in a previous fire brigade drill. In addition, the inspector identified a building on the turbine deck that was not identified in the pre-fire plans. An inspector concern was that the fire protection staff did not know how to access this space. The licensee had scheduled a plant walkdown to update the pre-fire plans during 1996.

F7 Quality Assurance in Fire Protection Activities (64704)

F7.1 Audits and QA Surveillance

Audit investigations for fire protection were detailed and thorough with adequate staff hours devoted to each audit. The field monitoring reports were performance based observations of conditions in the plant and were effective in identifying fire protection program problems. In addition, PIFs and licensee evaluations were effective at identifying fire protection problems.

U1 UFSAR Commitments Found in Agreement with Plant Design

U1.1 General Comments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

U1.2 UFSAR Section 9.1.2.3.2, Storage on Unit 1 Spent Fuel in the Unit 2 and 3 Spent Fuel Storage Racks.

The UFSAR states that, Unit 1 fuel may be stored symmetrically starting in the center of the rack and be limited to 63 fuel assemblies per 9x13 rack array and 49 fuel assemblies per 9x11 rack array. The inspectors identified three 9x11 rack arrays in each unit's spent fuel pool which contained Unit 1 spent fuel assemblies. Two of the racks in each pool contained 49 unit 1 assemblies arranged in a 7x7 symmetrical pattern. The other two racks (one in each unit's pool) contained six assemblies in the Unit 2 rack and seven in the Unit 3 pool. These assemblies were also arranged in a symmetrical pattern.

U1.3 UFSAR Section 9.1.3, Spent Fuel Pool Cooling and Cleanup System.

The UFSAR states the system was designed to provide enough filtering capacity to filter the spent fuel pool water volume every 12 hours. Further, the UFSAR stated that the pumps, heat exchangers, and demineralizer were located in the reactor building near the spent fuel pool. The inspectors verified that the description in the UFSAR and the "as built" configuration of the system matched.

U2 UFSAR Commitments Found Contrary to Plant Design (71707)

U2.1 General Comments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors.

U2.2 Incorrect Containment Locked Valve Status

Tables 6.2-10 and 11 of the UFSAR identify locked closed containment isolation valves for Units 2 and 3 respectively. There appeared to be several discrepancies in the listings (i.e., 2-2301-41B/42B are identified with two penetrations-X312 and X317; 2-1501-24B was not listed while 3-1501-24B was listed). (See Sections O3.2 and E4.2 for additional information.)

U2.3 Diesel Fuel Oil Storage Tank Overflow

Section 9.5.4, Diesel Generator Fuel Oil Storage and Transfer System (page 9.5-6) of the UFSAR states that the "Day tank overflow is routed to the fuel oil storage tank." However, drawing M-41, Sheet 2 (UFSAR Figure 9.5-1) showed the day tank overflow as routed to the oil separator. The inspectors determined drawing M-41 is correct. (See Section E4.2 above.)

U2.4 ACAD System Status

Section 6.2.5.2 of the UFSAR states in part that "The ACAD system has been isolated and deenergized since it serves as a post-Loss of Coolant Accident (LOCA) oxygen source to the containment and has been judged by the NRC to be a post-LOCA hazard to safety. However, the ACAD system is required to remain fully operable." The inspectors noted that the ACAD systems' compressors were not "deenergized" but instead were in AUTO maintaining a 44 psig to 57 psig band. The system had not posed a post-LOCA hazard because the valves were verified closed and no abnormal nor emergency procedure directed initiation of the system. The licensee installed NCAD on Unit 2 during D2R14, and anticipated that NCAD will be operational for Unit 2 at the end of D2R14. The licensee prepared a revision to the UFSAR to describe the ACAD system configuration with Unit 2 ACAD permanently out of sērvice and Unit 3 ACAD still in service. (See Sections O3.3 and E4.2 above.)

U2.5 Toxic Gas Analyzer

Section 6.4.4.2, "Toxic Gas Protection," of the UFSAR states that the control room heating and air-conditioning system can be manually placed in an isolation/recirculation mode when the presence of toxic gases has been discovered. System realignment was accomplished through the use of implementing procedures, however, the procedures do not take into account actions needed if a Loss of Offsite Power (LOOP) or a LOCA has occurred. In both cases the realignment process could not be accomplished using the current implementing procedures, therefore, the configuration described in the UFSAR would not be met. The licensee was preparing changes to the procedures and plans to issue an LER.

U2.6 HPCI Dedicated Suction

Section 6.3.2.3.2 of the UFSAR states "...90,000 gallons of water are reserved exclusively for HPCI." Section 9.2.6.2 states in part that "...CCST (Contaminated Condensate Storage Tanks) 2/3 A and 2/3 B, are restricted to a minimum level of 90,000 gallons each because of the HPCI system makeup water requirements during a LOCA. This is accomplished by the design of the discharge lines from the tanks: all taps into the tank for non-emergency use are at higher elevations on the tank than the 90,000-gallon level." Later in the same section it states in part that the condensate makeup, condensate transfer and condensate jockey pumps take suction from the CCSTs above the 90,000 gallon level...." However, drawing M-35, Sheet 1, (UFSAR Figure 9.2-10) and actual plant configuration showed the condensate makeup, condensate transfer and condensate jockey pumps take suction from the 2/3 CCST "A" HPCI suction line at the bottom of the tank contrary to UFSAR descriptions.

Resolution of these UFSAR issues (Sections 2.2 through 2.6) will be tracked as an Unresolved Item pending review of the licensee's corrective actions (50-237;249/96002-11).

VI. Management Meetings

V1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on March 29, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary

PARTIAL LIST OF PERSONS CONTACTED

Licensee

S. Perry, Vice President, BWR Operations
S. Barrett, Radiation Protection Manager
R. Bax, Station Outage Manager
E. Connell, Design Engineering Superintendent

J. Chapdelaine, Work Control and Outage Manager
R. Freeman, Plant Engineering Superintendent
J. Heffley, Units 2 and 3 Station Manager
T. Nauman, Unit 1 Station Manager
T. O'Connor, Operations Manager
P. Swafford, Unit 2/3 Maintenance Superintendent

P. Tzomes, Support Services Director
R. Kundalkar, Site Engineering Manager
F. Spangenburg, Regulatory Assurance Manager
D. Winchester, Safety Quality Verification Director

INSPECTION PROCEDURES USED

IP 37551: On-site Engineering
IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 62703: Maintenance Observations
IP 64704: Fire Protection Program
IP 71707: Plant Operations
IP 82701: Operational Status of the Emergency Preparedness Program
IP 83822: Radiation Protection
IP 92901: Followup - Plant Operations
IP 92903: Followup - Engineering
IP 92904: Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-237/96002-01	URI	Inadequate Unit 2 drywell closeout inspection
50-237;249/96002-02	URI	Electrical and valve lineup checklist problems
50-237;249/96002-03	URI	Locked valve program problems
50-237;249/96002-04	IFI	ACAD operating band differences
50-237;249/96002-05A	VIO	Failure to follow EDG test procedure
50-237;249/96002-05B	VIO	Failure to adequately test emergency lighting
50-237;249/96002-06A	VIO	Inadequate corrective action to 4kV breaker maintenance
50-237;249/96002-06B	VIO	Inadequate corrective action for FME in CCSW
50-237;249/96002-07	URI	Untimely resolution of Operability Evaluations
50-237;249/96002-08	URI	Inadequate emphasis on design and licensing basis nonconforming conditions
50-237;249/96002-09	URI	Polyvinyl Chloride (PCV) usage was not well controlled.
50-237:249/96002-10	IFI	Completion of emergency lighting corrective actions
50-237:249/96002-11	URI	UFSAR Discrepancies

Closed

50-237/95015-08	URI Unexpected 100 psig discharge of all the HCU accumulators.
50-237;249/95002-06 IFI	Information regarding NRC and DOE emergency incident response was not included in EP training lessons plans.
50-237;249/95014-01 URI	Fuel pool cooling pump trips

Discussed

50-237;249/95009-04 IFI	Poor accident mitigation and lack of management direction in the TSC.
50-010/95015-06	URI Unit 1 ventilation practices.
50-237/94003-04	URI Licensee to rerun seismic and dead weight analyses on low pressure coolant injection piping.

LIST OF ACRONYMS USED

ACAD	Atmospheric Containment Atmosphere Dilution
BRC	Business Review Committee
CCST	Contaminated Condensate Storage Tank
CCSW	Containment Cooling Service Water
CFR	Code of Federal Regulations
CR	Control Room
DAP	Dresden Administrative Procedure
DATR	Dresden Administrative Technical Requirements
DES	Dresden Engineering Surveillance
DGP	Dresden General Procedure
DIS	Dresden Instrument Surveillance
DOA	Dresden Operating Abnormal
DOE	Department of Energy
DOP	Dresden Operations Procedure
DOS	Dresden Operations Surveillance
DTS	Dresden Technical Surveillance
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EMD	Electrical Maintenance Department
EOF	Emergency Operations Facility
EP	Emergency Preparedness
ERO	Emergency Response Organization
FHA	Fire Hazard Analysis
FME	Foreign Material Exclusion
gpm	Gallons Per Minute
GSEP	Generating Station Emergency Plan
HPCI	High Pressure Coolant Injection
HVAC	Heating, Ventilation, and Air Conditioning
IFI	Inspector Followup Item
IMD	Instrument Maintenance Department
IRB	Issues Review Board
kW	Kilowatt
LER	Licensee Event Report
LOCA	Loss Of Coolant Accident
MMD	Mechanical Maintenance Department
MW	Megawatt
NCAD	Nitrogen Containment Atmosphere Dilution
NSO	Nuclear Station Operator
NTS	Nuclear Tracking System
OSC	Operational Support Center
OE	Operability Evaluations
PIF	Problem Identification Form
psig	Pounds Square Inch Gage
PVC	Poly-Vinyl Chloride
RPT	Radiation Protection Technician

SQV	Site Quality Verification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item

Tab 20

DRESDEN 2 & 3

FIRE PROTECTION REPORT

Inspection Report Nos. 50-237/96012 and 50-249/96012

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
801 WARRENVILLE ROAD
LISLE, ILLINOIS 60532-4351

November 14, 1996

RECEIVED NOV 21 1996

EA 96-388
EA 96-389
EA 96-390

Mr. H. W. Keiser
Chief, Nuclear Operating Officer
Commonwealth Edison Company
Executive Towers West III
1400 Opus Place, Suite 300
Downers Grove, IL 60515

SUBJECT: NRC INSPECTION REPORT NOS. 50-237/96012(DRS);50-249/96012(DRS); 50-254/96016(DRS);AND 50-265/96016(DRS)AND NOTICE OF VIOLATION

Dear Mr. Keiser:

This refers to the inspection conducted on July 8 through October 17, 1996, at the Dresden and Quad Cities nuclear facilities. The purpose of the inspection was to determine whether activities authorized by the licenses were conducted safely and in accordance with NRC requirements. The inspection scope included a review of Appendix R hot short concerns (Dresden and Quad Cities); 4KV breaker hardened grease concerns (Dresden only); and previously identified electrical distribution system functional inspection (EDSFI) items (Dresden only). At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Based on the results of this inspection, one apparent violation was identified and 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. The apparent violation involved the failure to provide adequate protection to ensure that motor-operated valves necessary to achieve and maintain hot shutdown conditions were not susceptible to fire induced hot shorts. Spurious valve operation with mechanical damage to certain 10 CFR 50, Appendix R, designated valves could result in the loss of safe shutdown capability during a control room fire (Section E1.1.b(1)). The circumstances surrounding the apparent violation, the significance of the issue, and corrective actions were discussed with members of your staff at the exit meeting on October 17, 1996. As a result, it may not be necessary to conduct a predecisional enforcement conference in order to enable the NRC to make an enforcement decision. However, a Notice of Violation is not presently being issued for the inspection finding. Before the NRC makes its enforcement decision, we are providing you an opportunity to either: (1) respond to the apparent violation addressed in this inspection report within 30 days of the date of this letter; or (2) request a predecisional enforcement conference. Please contact Mr. Ronald Gardner at (630) 829-9751 within 7 days of the date of this letter to notify the NRC of your intended response.

In addition, the NRC has determined that a violation of NRC requirements occurred. The violation is cited in the enclosed Notice of Violation (Notice) and the circumstances surrounding it are described in detail in the subject inspection report. The violation concerns the use of an inadequate breaker maintenance procedure to maintain safety related 4KV breakers. This procedure directed an inappropriate sequence of lubrication steps, including the use of an incompatible degreaser. In addition, Dresden failed to control the use of incompatible chemicals, such as penetrating oils, that were used during breaker troubleshooting and maintenance. Also, a more rigorous review of 4KV Magne-Blast circuit breaker service advisory letters (SALs) may have led to identification of the hardened grease issue before the 3A low pressure coolant injection (LPCI) pump motor breaker failure on June 11, 1996 (Section E1.1.b(2)).

The NRC has concluded that information regarding the reason for the violation, the corrective actions taken and planned to correct the violation and prevent recurrence are already adequately addressed on the docket in Commonwealth Edison Company letter JSPLTR #96-0148, dated August 29, 1996, and this inspection report. Therefore, you are not required to respond to this letter unless the description therein does not accurately reflect your corrective actions or your position. In that case, or if you choose to provide additional information, you should follow the instructions specified in the enclosed Notice.

Your response to the apparent violation should be clearly marked as a "Response to An Apparent Violation in Inspection Report Nos. 50-237/96012(DRS);50-249/96012(DRS); 50-254/96016(DRS);50-265/96016(DRS)," and should include: (1) the reason for the apparent violation, or, if contested, the basis for disputing the apparent violation; (2) the corrective steps that have been taken and the results achieved; (3) the corrective steps that will be taken to avoid further violations; and (4) the date when full compliance will be achieved. Include in your response details describing management's decision process regarding the priorities and resource allocations that delayed correction of the hot short issue prior to 1996. You should include a discussion of assurances that similar nonconforming conditions do not exist at any of your other nuclear power plants and that site and/or corporate engineers are providing conservative recommendations to station management when addressing nonconforming conditions. In addition, Dresden did not consider the susceptibility of the Units 2 and 3 isolation condenser 1301-3 valve to IN 92-18 hot shorts to be a credible event. Include in your response the rationale behind Dresden's decision to not report this condition as outside the safe shutdown design basis of the plant (10 CFR 50.73(a)(2)(ii)(B)).

Your response should be submitted under oath or affirmation and may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate response is not received within the time specified or an extension of time has not been granted by the NRC, the NRC will proceed with its enforcement decision or schedule a predecisional enforcement conference.

In addition, please be advised that the characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review. You will be advised by separate correspondence of the results of our deliberations on this matter.

Two unresolved items were identified involving old EDSFI items. The first item involves the cable ampacity issue that was identified in 1991. About 350 cables require additional analyses. Even though Dresden was to complete their evaluation by the end of 1996, we consider your actions to be slow in resolving this issue. The second item involves the lack of 125 and 250Vdc breaker to breaker coordination for several nonsafety loads connected to the safety buses. If a nonsafety load faulted, the potential exists to lose the safety bus. This item is being referred to the Office of Nuclear Reactor Regulation (NRR) for further review.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response (if you choose to provide one) will be placed in the NRC Public Document Room (PDR). To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be placed in the PDR without redaction.

Sincerely,

Geoffrey E. Grant, Director
Division of Reactor Safety

Docket Nos. 50-237; 50-249
Docket Nos. 50-254; 50-265

Enclosures:
1. Notice of Violation
2. Inspection Report Nos.
   50-237/96012(DRS);
   50-249/96012(DRS);
   50-254/96016(DRS);
   50-265/96016(DRS)

See Attached Distribution

cc w/encls: J. S. Perry, Site Vice President
E. Kraft, Site Vice President
D. A. Sager, Vice President,
Generation Support
T. Nauman, Station Manager, Unit 1
M. Heffley, Station Manager, Units 2 and 3
L. W. Pearce, Station Manager
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N. Chrissotimos, Regulatory Assurance
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Richard Hubbard
Nathan Schloss, Economist,
Office of the Attorney General
State Liaison Officer
Chairman, Illinois Commerce Commission
J. R. Bull, Vice President, General &
Transmission, MidAmerican Energy Company

NOTICE OF VIOLATION

Commonwealth Edison Company
Dresden Station, Units 2 and 3

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

During an NRC inspection conducted on July 8 through October 17, 1996, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, the violation is listed below:

10 CFR 50, Appendix B, Criterion V, requires in part, that activities affecting quality be prescribed by documented procedures of a type appropriate for the circumstances and include appropriate qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Contrary to the above, Maintenance Procedure DES 6700-03, Revision 7, dated April 18, 1996, "Inspection and Maintenance of General Electric 4KV Magne-Blast Circuit Breakers Types AM-4.76-250-OD (Horizontal Drawout)," an activity affecting quality, was not appropriate for the circumstances in that it directed an inappropriate sequence of lubrication steps including the use of an incompatible degreaser. In addition, the licensee failed to control the use of incompatible chemicals, such as penetrating oils, that were used during breaker troubleshooting and maintenance. This resulted in hardened grease preventing the 3A Low Pressure Coolant Injection (LPCI) pump breaker from tripping open for ten seconds on June 11, 1996.

This is a Severity Level IV violation (Supplement I).

With regard to this violation, the NRC has concluded that the information regarding the reason for the violation, the corrective actions taken and planned to correct the violation and prevent recurrence and the date when full compliance was achieved is already adequately addressed in the enclosed inspection report (Nos. 50-237/96012(DRS); 50-249/96012(DRS)). However, you are required to submit a written statement or explanation pursuant to 10 CFR 2.201 if the description therein does not accurately reflect your corrective actions or your position. In that case, or if you choose to respond, clearly mark your response as a "Reply to a Notice of Violation" and send it to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555, with a copy to the Regional Administrator, Region III, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice).

Dated at Lisle, Illinois
this 14th day of November 1996

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-237; 50-249; 50-254; 50-265
License Nos:	DPR-19; DPR-25; DPR-29; DPR-30
Report Nos:	50-237/96012(DRS); 50-249/96012(DRS); 50-254/96016(DRS); 50-265/96016(DRS)
Licensee:	Commonwealth Edison Company
Facility:	Dresden Nuclear Station Units 2 and 3 Quad Cities Nuclear Station Units 1 and 2
Location:	6500 N. Dresden Road Morris, IL 60450 22712 206th Avenue North Cordova, IL 61242
Dates:	July 8 through October 17, 1996
Inspector:	D. S. Butler, Reactor Inspector
Approved By:	R. N. Gardner, Chief, Engineering Specialists 2 Division of Reactor Safety

EXECUTIVE SUMMARY

Dresden Nuclear Station Units 2 and 3
NRC Inspection Report Nos. 50-237/96012(DRS); 50-249/96012(DRS)
Quad Cities Nuclear Station Units 1 and 2
NRC Inspection Report Nos. 50-254/96016(DRS); 50-265/96016(DRS)

This regional inspection reviewed the licensee's efforts to address Appendix R hot short vulnerabilities (Dresden and Quad Cities), 4KV breaker hardened grease concerns and the status of previously identified electrical distribution system functional inspection (EDSFI) items (Dresden). The following weaknesses were identified:

Engineering

- Inadequate review of NRC and industry initiatives contributed to safe shutdown vulnerabilities (Dresden and Quad Cities) and contributed to 4KV breaker hardened grease concerns (Dresden).

- A more thorough OPEX program review of industry initiatives may have identified the hardened grease issue before Dresden's 3A LPCI pump breaker failed.

- Dresden's actions to address cable ampacity concerns have been slow in resolving this issue.

Report Details

III. Engineering

E1 Engineering Support of Facilities and Equipment

E1.1 Engineering Review of NRC and Industry Initiatives

a. Inspection Scope (37551)

The inspector reviewed the circumstances surrounding a potential condition outside the facility's Appendix R design basis and the corrective actions taken by the licensee to prevent hardened grease buildup in 4KV circuit breakers.

b. Observations and Findings

(1) Potential for Loss of Shutdown Capability During A Control Room Fire (Dresden and Quad Cities)

(a) Background

In the mid-1980s, the licensee identified the potential for hot shorts to affect motor operated valves (MOVs) during postulated plant fires. The Stations assumed these valves would be available for manual realignment following control room evacuation. Provisions were made in the safe shutdown procedures to open individual MOV circuit breakers in preparation for manual operation of the valves.

On February 28, 1992, the NRC issued IN 92-18. This IN described the potential for loss of remote shutdown capability during a control room fire. This fire could cause hot shorts, such as short circuits between motor operated valve (MOV) control circuit conductors and their control power source that initiate spurious operation of certain MOVs before the operators shift control of the valves to the remote/alternate shutdown panel. (Dresden and Quad Cities do not have remote/alternate shutdown panels, but rely on the opening of individual valve circuit breakers to remove electrical power.) Motor thermal overload (TOL) protection may be bypassed, set high or set with a longer tripping time to allow for additional valve duty cycles and/or reversing of the MOV during stroking. The IN identified that MOV torque and limit switches would not electrically disconnect a stroking valve due to the hot short bypassing the limit and torque switches. This had the potential to cause mechanical damage to the valve and/or damage the motor.

The IN was tracked in Dresden's Nuclear Tracking System (NTS) by item No. 237-103-92-01801 and had an Item Date of February 28,

1992. The NTS item indicated that a preliminary hot short assessment of Dresden and Quad Cities did not show an unanalyzed condition existed.

On August 13, 1992, the Nuclear Management and Resources Council (NUMARC) issued a letter to NUMARC administrative points of contacts regarding IN 92-18. The letter stated, "We suggest careful consideration by utility management of any plans regarding plant design changes in response to IN 92-18." This included a suggestion that the potential costs involved in making any design modifications to prevent the adverse effects of the hypothetical hot shorts, may be large compared with the risk significance.

Per an October 1, 1992, letter, the licensee determined that IN 92-18 was applicable to all ComEd Stations and suggested that the Nuclear Engineering Department (NED) conduct an in-depth review of the Safe Shutdown Analyses (SSAs).

On July 6, 1993, Sargent and Lundy (S&L) letter No. D-0686M identified to Dresden that three valves per Unit could be affected by the IN control room fire hot short scenario. S&L recommended rewiring the MOVs or resizing thermal overload (TOL) heaters to de-energize the valve contactors and stop valve movement before the valve assembly was physically damaged. No action was taken by the licensee.

On August 31, 1993, S&L letter No. Q-0745M identified to Quad Cities that about 30 valves per Unit could be affected by a control room fire. S&L recommended rewiring the MOVs or resizing thermal overload (TOL) heaters to de-energize the valve contactor and stop valve movement before the valve assembly was physically damaged. However, this S&L letter referenced the NUMARC letter and stated, "Before taking any action concerning this review, please review the enclosed NUMARC letter dated August 13, 1993." No action was taken by the licensee.

On March 26, 1994, Quad Cities site engineering evaluated (Chron # 0300239) IN 92-18. Support engineering determined that hot shorts did not pose a concern at Quad Cities based on the following:

- Quad Cities MOVs had TOL protection. The TOLs were sized to trip on excessive locked rotor current and prevent damage to the valve.

- MOV circuits were wired in various configurations such that a hot short may or may not bypass an MOV limit and/or torque switch. The probability of a hot short over-torquing a valve was considered low.

- The majority of the motor control circuits were wired as a floating (ungrounded) circuit. Therefore, a hot short of an MOV control conductor to an independent power source would not cause valve actuation for a control room fire. If the valve control circuit were grounded, then the above two considerations would protect the MOV.

- Safe shutdown procedures were designed to de-energize the power source to affected valves and sequentially close required equipment breakers as needed. Thus, "the QARP procedures affectively render the affects of Smart Hot Shorts originating from the Control Room void."

Per a December 22, 1994, letter, the licensee's probability risk assessment (PRA) group recommended that the valve control circuit design not be modified at Dresden and Quad Cities due to low probability of the hot short event.

In 1996, both Dresden (December 1995) and Quad Cities had initiated their biannual fire protection update. The Fire Protection Report (FPR) and Fire Protection Program Documentation Package (FPPDP) were updated during this review. This included the Appendix R Safe Shutdown Analysis and Fire Hazard Analysis Report. By May 1996, Quad Cities was informed by a fire protection contractor that TOLs may not protect a valve from mechanical damage for an IN 92-18 control room fire. The contractor had recently participated in an Appendix R review at another RIII licensed facility. Quad Cities notified Dresden and both Stations re-reviewed IN 92-18 and concluded they were susceptible to hot short induced valve mechanical damage.

(b) Discussion

Both Dresden and Quad Cities designs used TOLs to protect MOV motors. However, in some instances, the TOL tripping time had been increased to meet NRC Generic Letter No. 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," requirements. The licensees initiated weak-link reviews and concluded that certain MOVs may be mechanically damaged before the motor's TOL tripped. This could prevent an operator from repositioning valves that experienced spurious operation due to a hot short. Dresden identified three valves per Unit that required modification. One valve (MO 2(3)-1301-3, Isolation Condenser RX Inlet Isolation Valve), per Unit was modified. The remaining two isolation valves (MO 2(3)-1201-2 and -3) did not create a hot short concern since procedure steps already existed that isolated reactor water cleanup (RWCU) utilizing other valves. Approximately 30 Quad Cities valves per Unit were modified by electrically placing the torque and limit switches between the areas where potential hot shorts could occur and each valve's open and closed contactor. The modifications did not change the electrical operation of the valves. The difference in numbers of valves per Station was due to Dresden having an isolation condenser. The inspector reviewed several design packages from both Stations and concluded that the changes would alleviate the concern identified in the IN. All affected Appendix R valves have been modified at both Stations.

Although the licensee corrected the hot short concern once identified, engineering's initial IN 92-18 review was inadequate. Engineering had concluded the probability was low for Dresden and Quad Cities to have a hot short concern and recommended no corrective actions.

(c) Safety Significance

This issue has safety significance in that spurious operation induced mechanical damage to 10 CFR 50, Appendix R, designated valves could result in the loss of safe shutdown capability during a control room fire. Both Stations' safe shutdown procedures required manual manipulation of these Appendix R valves following electrical isolation.

Both Stations had multiple opportunities to identify the hot short concern. The failure to provide adequate protection to ensure operation of equipment necessary to achieve and maintain hot shutdown is considered an apparent violation (50-237/96012-01(DRS); 50-249/96012-01(DRS); 50-254/96016-01(DRS); 50-265/96016-01(DRS)) of 10 CFR 50, Appendix R, III.G.2 and III.G.3. This closes Unresolved Item 50-254/96008-11(DRS); 50-265/96008-11(DRS). This condition had existed since the mid-1980s.

(2) Hardened Grease in 4KV Magne-Blast Circuit Breakers (Dresden Only)

(a) Background

During the 1989 NRC maintenance team inspection, the NRC identified a corrective action violation (50-237/88029-02(DRS); 50-249/88030-02(DRS)) concerning a sticking 2D low pressure coolant injection (LPCI) pump 4KV breaker trip latch roller mechanism. The violation was issued to the licensee on April 4, 1989. The maintenance team identified that the root cause for the breaker failure was a lack of preventive maintenance. As part of the licensee's corrective actions, a review was initiated of 4KV maintenance procedures, surveillances, breaker manuals and updates to the manuals at all ComEd facilities.

On July 7, 1995, General Electric (GE) issued Service Advisory Letter (SAL) No. 352.1, which summarized past vendor correspondence and design updates for GE Magne-Blast breakers and cubicles.

On August 25, 1995, GE issued SAL No. 354.1, which delineated GE's recommendations for breaker lubrication practices and preventive maintenance frequencies.

On January 18, 1996, the licensee identified an adverse trend in the performance of horizontal lift 4KV breakers. An interdisciplinary team was assembled to investigate the trend.

During the February 14 through March 29, 1996, NRC inspection period (NRC Inspection Report Nos. 50-237/96002; 50-249/96002), the NRC reviewed past 4KV breaker maintenance history records and concluded the licensee had inadequately resolved previously identified 4KV breaker problems. A corrective action violation (50-237/96002-06A; 50-249/96002-06A) was issued to the licensee on May 20, 1996.

On June 11, 1996, the 3A LPCI pump breaker did not trip open during routine surveillance testing. The licensee began an extensive review of the breaker failure. Four spare breakers were inspected. Two of the four spare breakers inspected exhibited hardened grease symptoms. However, they both operationally tripped at a rated undervoltage of 70 volts.

On June 19, 1996, the licensee responded to corrective action violation 50-237/96002-06A; 50-249/96002-06A. In addition, the licensee's interdisciplinary team concluded that past ineffective corrective actions and the lack of technical documentation had contributed to inadequate breaker preventive maintenance. Management conservatively concluded that Unit 3 should be shut down to perform corrective maintenance on the 4KV breakers. Unit 2 was already shut down due to unrelated problems.

On June 20, 1996, the licensee formed an event response team. The team was chartered to establish the root cause, verify current breaker technical information, resolve discrepant conditions found during testing, recommend appropriate corrective actions, track as-found conditions in the breakers and recommend retests to assure reliable operation.

On July 17, 1996, the licensee amended their response to violation 50-237/96002-06A; 50-249/96002-06A. In part, the licensee's response indicated that the adverse 4KV breaker trend dealt exclusively with breaker and cubicle alignment problems associated with racking the breakers in and out. The identified failures were attributed to electrical switches and associated linkages that connect the breaker to the breaker cubicle and not the internal breaker mechanical sections.

(b) Discussion

The inspector reviewed the licensee's root cause investigation report, dated August 29, 1996, "4KV Breakers - Hardened Grease in Trip Latch Roller Bearings." The hardened grease issue was previously discussed in NRC Inspection Report Nos. 50-237/96006; 50-249/96006.

On June 11, 1996, the 3A LPCI pump breaker did not trip open during routine surveillance testing. The breaker tripped after the main control room switch was placed in pull-to-lock for about ten seconds. The breaker type was a General Electric (GE) magne-blast horizontal-lift, model AMH-4.76-250-OD. Licensee investigation identified that hardened grease on the trip latch roller bearing caused the trip mechanism to be unreliable. The increased frictional forces between the trip latch and the trip latch roller could not be overcome by the trip coil. Two of four spare breakers inspected also had symptoms of hardened grease. The licensee with GE assistance prepared and implemented a comprehensive 4KV breaker inspection, maintenance and test plan. Cubicles, linkages, auxiliary switches and breakers were examined and refurbished as required. All inservice 4KV safety related breakers were overhauled. In addition, tests were performed on several spare breakers obtained from Quad Cities. This included grease analysis and maintenance practice reviews. The first noted difference between the two Stations was that Dresden used a volatile degreaser applied from an aerosol can, where Quad Cities only used denatured alcohol when cleaning breaker parts. The second noted difference was in the maintenance procedure steps. Following cleaning, Quad Cities applied a light film of SAE 10 weight turbine oil while Dresden applied a light film of grease followed by a light film of SAE 20 to 30 weight oil. Analysis of Dresden's grease identified that the use of volatile degreasers "washed away" lighter lubrication components of the original "white" grease, leaving a thicker, stiffer grease. In addition, by applying the grease first, Dresden kept the oil from permeating the bearing and refreshing the grease. In actuality, Dresden was over-greasing and accelerating the grease hardening process. The root cause analysis also concluded that Dresden had used low quality penetrating oils during troubleshooting and maintenance. These oils appeared to have a short term benefit by freeing up sticking mechanical mechanisms. However, in the long term they were not refreshing the grease, since lightweight, volatile components of the penetrating oils evaporated over time. The uncontrolled use of different chemicals at Dresden may have caused a grease compatibility problem and accelerated the hardening of the grease. General Electric indicated in 1984 that low quality penetrating oils should not be used to revitalize grease and retracted their recommendation to use penetrating oils to refresh greases used in 480 volt AK-25 breakers. The Quad Cities grease analysis identified that their lubricating practices had refreshed the grease, slowed oxidation of the grease, and ensured the grease still had lubricating properties. The investigation team concluded that hardened grease caused the 3A LPCI pump breaker failure.

In addition, the licensee's team identified two concerns associated with the Operational Experience Report (OPEX) program. This program was used to review NRC Information Notices, Bulletins, Generic Letters and industry information. The licensee's team identified that GE SALs related to the 4KV breakers had been inadequately controlled. Although the SALs did not directly identify a hardened grease issue, a thorough review of the SALs may have led to the identification of the hardened grease issue before the 3A LPCI pump breaker failed. The second concern identified a recurring theme that breaker failures had been caused by inadequate lubrication.

(c) <u>Safety Significance</u>

During a design basis accident (DBA) concurrent with a loss of offsite power (LOOP), the failure of the LPCI motor (if already running) breaker to trip open had the potential to load the pump on the emergency diesel generator (EDG) out of sequence. The LPCI pump would restart when the EDG output breaker closed along with 480 volt auxiliary loads. This had minimal safety significance, since the EDG load at breaker closure would be less than the load when the core spray pump started with two LPCI pumps already running. Starting the LPCI pump early would not affect the safety analysis, since the pump would be operating on recirculation flow, which is the normal flow produced by the pump until reactor pressure decreases low enough to inject. The inspector reviewed portions of calculation No. 9389-46-19-3, Revision 0, "Diesel Generator 2/3 Loading Under Design Bases Accident Conditions." The MP45 Dead Load Pickup Capability lock rotor curve for Dresden's EDGs indicated that the voltage would recover to about 95% in less than one second during the starting of the LPCI pump and auxiliary loads. This would provide sufficient voltage to all starting loads and not affect continued EDG loading.

Dresden had multiple opportunities to identify deficient 4KV breaker maintenance. The inspector concluded that maintenance procedure DES 6700-03, Revision 7, "Inspection and Maintenance of General Electric 4KV Magne-Blast Circuit Breakers Types AM-4.76-250-OD (Horizontal Drawout)," was inadequate. The procedure approved the use of the degreaser and a sequence of procedure lubrication steps that contributed to the hardened grease issue. In addition, various unapproved chemicals were used when performing breaker maintenance. This is considered a violation (50-237/96012-02(DRS); 50-249/96012-02(DRS)) of 10 CFR 50, Appendix B, Criterion V. This closes Unresolved Item 50-237/96006-05;50-249/96006-05. Also, a more thorough OPEX program review of industry initiatives may have identified the hardened grease issue sooner and prevented the 3A LPCI pump-breaker failure.

c. Conclusion

The inspector concluded that engineering had performed inadequate reviews of the original Appendix R hot short design requirements, and weak reviews of NRC and industry initiatives for both of the above concerns. However, once the identified concerns were fully understood by the licensee, the Stations aggressively resolved the concerns and made conservative engineering and maintenance decisions.

E1.2 Resolution of Old (Original) Design Issues (Dresden Only)

a. Inspection Scope (37551)

Regional NRC inspectors had reviewed and closed all of the 1991 EDSFI items based on commitments made by the licensee. The following details describe the EDSFI items that are open in the licensee's tracking system.

b. Observations and Findings

(1) 4KV Breaker Overduty

Dresden's Updated Final Safety Analysis Report stated in Section 8.3.1, "AC Power Systems," that all protective circuit breakers were sized to interrupt the maximum available line-to-line or three phase short circuit current. The EDSFI team identified that certain 250MVA and 350MVA switchgear breakers could be subjected to fault currents that exceeded their maximum interrupting and momentary ratings.

In response, the licensee strengthened the bus bracing in the nonsafety 350MVA switchgear cubicles and upgraded safety related 250MVA breakers to 350MVA SF6 breakers. However, the 350MVA switchgear analysis identified that an overduty condition could still occur if two reactor feedwater pumps and two reactor recirculation pump motor-generator (MG) sets were fed from the same transformer. The licensee refined the short circuit analysis and concluded that the available fault current was within the original design breaker ratings. However, the breaker manufacturer indicated that they had decreased the nonsafety 350MVA breaker ratings.

During normal plant operation, a recirculation pump MG set and one motor-driven feedwater pump were fed from one transformer. The other recirculation pump and motor-driven feedwater pump were fed from a second transformer. A third non-running motor-driven feedwater pump was maintained in standby and would only be used if one of the running feedwater pumps tripped. In this alignment, the nonsafety 350MVA breakers could safely interrupt a three phase fault at the bus. The licensee concluded that the probably of a bus fault was low. In addition, a nonsafety 4KV motor load would only be added to the other transformer if it's own transformer feed was lost. The loss of a second transformer feed would place a Unit in a seven day Technical Specification (TS) limiting condition of operation (LCO) and initiate actions to restore the normal alignment. The overduty issue was not a concern during a design basis accident, since the recirculation pump MG sets would be automatically tripped.

The inspector reviewed the above information and concluded that the nonsafety 350MVA breaker overduty issue had minimal safety impact.

(2) Balance of Plant Electrical Load Monitoring System (ELMS)

The licensee developed a program to gather electrical voltage and current data for transformers, motors and other loads during various operating conditions. The collection of load flow data should be completed in 1997. Additional monitoring equipment was being purchased and installed. Because of EDSFI degraded voltage concerns, the licensee had developed a program to obtain similar information for safety related loads. This data was used to support degraded voltage setpoint calculations. Completing the collection of balance of plant load flow data should give the licensee a representative model of actual plant electrical and current requirements. The inspector had no further questions at this time.

(3) 480Vac Breaker Coordination

The EDSFI team identified that full electrical coordination did not exist from several load breakers to their upstream feed breaker. This was considered a design weakness by the EDSFI team; however, this design was consistent with the original design basis.

In response, the licensee acknowledged that better coordination was desirable. The licensee has replaced the original design EC-2 electro-mechanical trip devices with solid-state RMS-9 Micro Versa Trip devices. However, six breakers per Unit were in a harsh environment zone. To date, the licensee has not been successful in environmentally qualifying (EQ) the RMS-9 trip device. The licensee was continuing their efforts to obtain an environmentally qualified device. In both Units, the licensee has installed new EC-2 devices in the six EQ breakers. The licensee determined that full coordination existed except when divisional buses were crosstied. However, the paralleling of redundant buses was not permitted during power operation. The crosstie breakers were administratively controlled open. The inspector concluded the licensee had addressed 480Vac breaker coordination in an acceptable manner.

(4) Adequacy of Cable Ampacity

The licensee was unable to provide the EDSFI team documentation to establish that cables were properly sized.

In response, the licensee committed to evaluate cable ampacity concerns. The Sargent and Lundy Interactive Cable Engineering (SLICE) program was used to identify overloaded cables. Field temperature and current measurements were taken to determine a conservative means of qualifying geometric and system diversity. The licensee indicated that about 350 cables required additional analyses. This program was tentatively scheduled for completion by the end of 1996.

This is considered an Unresolved Item (50-237/96012-03(DRS); 50-249/96012-03(DRS)) pending NRC followup on the licensee's corrective actions, and review of the operability determinations for safety related cables with ampacity concerns. Resolution of this previously identified concern has been ongoing since 1991.

(5) DC System Coordination

The EDSFI team considered the lack of 125 and 250Vdc molded case to molded case circuit breaker coordination to be a design weakness. However, licensee reviews of original design and licensing documents did not identify any requirements or commitments to establish full coordination. The lack of full coordination was due to molded case circuit breakers connected in series. Selective coordination was achieved in the overcurrent (thermal) region, but coordination in the instantaneous (magnetic) region was difficult. Miscoordination in the instantaneous region occurred for faults at the bus. Cable faults would have to occur close to the breaker output terminals, since additional cable length would limit the fault current and may coordinate with the bus feed breaker. The inspector discussed this issue with the Office of Nuclear Reactor Regulation (NRR) electrical branch. NRR indicated that molded case circuit breaker coordination was difficult to establish in the instantaneous range. In addition, NRR indicated that the probability of a fault occurring at the bus or in the cable was low. The most probable fault would occur at the load.

The inspector was concerned that nonsafety loads supplied by safety related DC buses could fail during a design basis accident, and without full electrical coordination, cause safety related functions to be lost. The licensee initiated a calculation to determine if nonsafety loads had sufficient cable length to limit the fault current at the load. Calculation results indicated that several nonsafety motor loads would not fully coordinate with the bus feed breaker for a load fault. The licensee re-emphasized to the inspector that this was part of their original design. This is considered an Unresolved Item (50-237/96012-04(DRS); 50-249/96012-04(DRS)) for NRR to review safety related 125 and 250Vdc molded case circuit breaker coordination at Dresden. The licensee is not required to respond to this item at this time.

(6) Overcurrent Protection of Unit Substation Transformers

The EDSFI team noted that overcurrent relays did not fully protect 480 volt substation transformers for a secondary fault. However, reviews of original design and licensing documents did not identify any requirements or commitments by the licensee to establish full coordination. The team viewed this design weakness as a personnel safety issue.

In response, the licensee indicated that various design changes were being reviewed. Options included the installation of additional protective relays or replacing the transformers. The review determined that the above changes were not cost effective. The licensee indicated that full coordination would be considered if transformer replacement was deemed necessary. The inspector had no further questions at this time.

c. Conclusion

The inspector concluded that the on-site electrical engineering group was pursuing engineering solutions to old (original) design issues. However, engineering's resolution of cable ampacity concerns has not been completed. Although tentatively scheduled for completion in 1996, the cable ampacity concern has existed since 1991.

II. Management Meetings

The inspector 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 inspector 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
M. Heffley, Units 2 and 3 Station Manager
T. O'Connor, Operations Manager
R. Kundalkar, Site Engineering Manager
R. Holbrook, Training Manager
F. Spangenberg, Regulatory Assurance Manager
J. Brownell, Fire Protection Engineer, Quad Cities Station
W. Porter, Programs Group Lead, Quad Cities Station

NRC

C. Vanderniet, Senior Resident Inspector
J. Hansen, Resident Inspector
J. Hopkins, Regional Inspector
M. Urano, Nuclear Power Engineering Corporation, Japan

IDNS

C. Settles, Resident Inspector

INSPECTION PROCEDURE USED

IP 37551: On-Site Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-237/96012-01(DRS); 50-249/96012-01(DRS); 50-254/96016-01(DRS); 50-265/96016-01(DRS)	VIO	Inadequate safe shutdown, hot short design review (IN 92-18)
50-237/96012-02(DRS); 50-249/96012-02(DRS)	VIO	Inadequate 4KV breaker maintenance procedure
50-237/96012-03(DRS); 50-249/96012-03(DRS)	URI	Adequacy of cable ampacity
50-237/96012-04(DRS); 50-249/96012-04(DRS)	URI	Adequacy of the 125 and 250Vdc systems electrical coordination

Closed

50-237/96006-05(DRP); 50-249/96006-05(DRP)	URI	4KV breaker failure to trip
50-254/96008-11(DRS); 50-265/96008-11(DRS)	URI	Electrical hot shorts (IN 92-18)

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
DBA	Design Basis Accident
DES	Dresden Electrical Surveillance
EDG	Emergency Diesel Generator
EDSFI	Electrical Distribution System Functional Inspection
GE	General Electric
ELMS	Electrical Load Monitoring System
EQ	Environmental Qualification
FPPDP	Fire Protection Program Documentation Package
FPR	Fire Protection Report
IFI	Inspector Followup Item
IN	Information Notice
KV	Kilovolts
LCO	Limiting Condition of Operation
LOOP	Loss of Offsite Power
LPCI	Low Pressure Coolant Injection
MOV	Motor Operated Valve
MVA	Million Volt-Amperes
NED	Nuclear Engineering Department
NOV	Notice of Violation
NRR	Office of Nuclear Reactor Regulation
NTS	Nuclear Tracking System
NUMARC	Nuclear Management and Resources Council (NEI)
OPEX	Operational Experience Report Program
PRA	Probability Risk Assessment
QARP	Quad Cities Alarm Response Procedure
RX	Reactor
RWCU	Reactor Water Cleanup
SAL	Service Advisory Letter
SAE	Society of Automotive Engineers
S&L	Sargent & Lundy
SLICE	Sargent & Lundy Interactive Cable Engineering
SSA	Safe Shutdown Analyses
TOL	Thermal Overload
TS	Technical Specification
TSUP	Technical Specification Upgrade Program
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
Vac	Volts alternating-current
Vdc	Volts direct-current
VIO	Violation

ESK-96-224

December 12, 1996

U.S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Document Control Desk

Subject: Response to An Apparent Violation in Inspection Report Nos. 50-237/96012(DRS); 50-249/96012(DRS);50-254/96016(DRS); 50-265/96016(DRS)
Protection of Motor Operated Valves During Postulated Hot Shorts
NRC Docket Nos. 50-237/249 and 50-254/265

Reference: NRC Inspection Report Nos. 50-237/96012(DRS); 50-249/96012(DRS); 50-254/96016(DRS); 50-265/96016(DRS), dated November 14, 1996.

The Reference Inspection Report discusses the results of the NRC staff's special inspection regarding fire protection issues at Dresden and Quad Cities. In the Reference NRC Inspection Report, the NRC staff identified one apparent violation that is being considered for escalated enforcement action for Dresden and Quad Cities. In lieu of a predecisional enforcement conference, ComEd is submitting this letter in response to the Inspection Report.

The apparent violation identifies a concern with the protection of motor operated valves during a postulated control room fire leading to a "hot short". Under certain limited conditions, a fire induced hot short in the control circuit of a motor operated valve can lead to spurious valve operation and mechanical damage to the valve operator.

ComEd concurs that "hot shorts" with possible mechanical damage to the valve is a valid technical issue which is applicable to Dresden and Quad Cities Stations. We have expeditiously taken action at both sites to minimize its impact. However, ComEd does not believe this issue was part of our original design basis.

The circumstances surrounding the apparent violation, ComEd's response to these circumstances, the corrective actions already taken for the technical issue, and the significance of the issue are discussed in the attachment to this letter. The Quad Cities and Dresden responses may be found in Attachments A and B respectively. Attachment C provides the additional information requested in the Inspection Report.

By separate correspondence, ComEd will provide additional information with respect to the other ComEd sites and corporate and/or site engineering staff conservative recommendations.

ComEd appreciates the opportunity to respond to these concerns. If there are any further questions regarding this issue, please contact either Charles Peterson at Quad Cities or Frank Spangenberg at Dresden Station.

Respectfully,

E. S. Kraft, Jr.
Site Vice President
Quad Cities Station

Attachments (A), Quad Cities' Response to An Apparent Violation
(B), Dresden's Response to An Apparent Violation
(C), Request for Additional Information

cc: A. B. Beach, Regional Administrator - RIII
C. L. Vandemiet, Senior Resident Inspector - Dresden
C. G. Miller, Senior Resident Inspector - Quad Cities
J. F. Stang, Project Manager - NRR
R. M. Pulsifer, Project Manager - NRR
Office of Nuclear Facility Safety - IDNS
R. J. Singer, MidAmerican Energy
D. C. Tubbs, MidAmerican Energy
DCD License (both electronic and hard copy)

Subscribed and Sworn to before me on this
______ day of ______, 1996

____
Notary Public

ATTACHMENT A (Page 1 of 2)
ESK-96-224

Response to An Apparent Violation in Inspection Report Nos. 50-237/96012(DRS);
50-249/96012(DRS);50-254/96016(DRS);50-265/96016(DRS)
For Quad Cities Station

STATEMENT OF APPARENT VIOLATION

The failure to provide adequate protection to ensure operation of equipment necessary to achieve or maintain hot shutdown is considered an apparent violation of 10CFR50, Appendix R, III.G.2 and III.G.3.

REASON FOR VIOLATION

Quad Cities Station agrees with the violation. The cause of the event was a cognitive design analysis review error in that the original methodology used to review circuit failure modes for Appendix R safe shutdown (SSD) did not include mechanical damage from fire induced hot shorts as a failure mode.

Quad Cites Station was analyzed for the effects of hot short induced spurious operation of valves for each of the sixteen (16) SSD paths. However, the analysis did not address the potential for a hot short to bypass the torque and limit switches, which in some instances could result in damage to the valve or actuator. The resulting damage could potentially prevent the subsequent valve positioning required for performance of the safe shutdown procedure.

CORRECTIVE ACTIONS TAKEN AND RESULTS ACHIEVED

On July 8, 1996, as a result of an independent self assessment of fire protection, Quad Cities identified its vulnerability to hot short induced mechanical damage. A Problem Identification Form (PIF) was initiated.

The affected SSD paths were immediately declared inoperable and a subsequent ENS notification was made. Licensee Event Report 96-011 was submitted on August 7, 1996.

A thorough analysis was performed of all one hundred fourteen (114) Motor Operated Valves (MOV) required for SSD. The analysis identified MOVs vulnerable to a single fire induced hot short that could lead to self-disabling damage.

Prior to declaring the SSD paths operable, the circuitry of fifty nine (59) valves was modified to eliminate the vulnerability to fire induced hot shorts. The remaining fifty five (55) valves were not modified due to analyses either concluding that the valves were not susceptible to damage [seven (7) valves] or that revision of procedures adequately addressed the issue [forty eight (48) valves]. In addition, all sixteen (16) SSD procedures were revised so that procedural actions would be in place to mitigate the affects of a fire induced hot short.

ATTACHMENT A (Page 2 of 2)
ESK-96-224

Response to An Apparent Violation in Inspection Report Nos. 50-237/96012(DRS); 50-249/96012(DRS);50-254/96016(DRS);50-265/96016(DRS)
For Quad Cities Station

Discussion of Delayed Correction

The conditions noted in IEN 92-18 were reviewed by Quad Cities Station. The closure of this review in March 1994 concluded that this issue did not apply to Quad Cities, primarily because MOV thermal overloads were not bypassed. In 1996, information indicating that thermal overload protection retained in the circuit may not protect a MOV, became available to Quad Cities. This initiated our second review of IEN 92-18. Quad Cities' corrective actions occurred expeditiously upon determination that the technical issue had not been adequately resolved.

Currently, information notices are screened for applicability to Quad Cities, assigned a responsible department and assigned a tracking number to ensure timely completion. See Attachment C for further details.

ACTIONS TO PREVENT FURTHER OCCURRENCE

The site has taken steps to emphasize more conservative decision making when resolving engineering issues as evidenced by the number of issues recently reviewed and resolved. Some of these were reviews of previous decisions or resolution of long standing problems.

Spurious valve operation from hot shorts and the lessons learned from our resolution of this issue will be discussed in engineering continuing training and will be included in site initial training for new engineers.

No further actions are required since the vulnerability of SSD MOV's to the adverse affects of fire induced hot shorts on SSD have been eliminated.

DATE WHEN FULL COMPLIANCE WILL BE MET

Quad Cities is currently in full compliance.

ATTACHMENT B (Page 1 of 2)
ESK-96-224

Response to An Apparent Violation in Inspection Report Nos. 50-237/96012(DRS); 50-249/96012(DRS);50-254/96016(DRS);50-265/96016(DRS)
For Dresden Station

RESTATEMENT OF APPARENT VIOLATION

The failure to provide adequate protection to ensure operation of equipment necessary to achieve and maintain hot shutdown is considered an apparent violation of 10CFR50, Appendix R, III.G.2 and III.G.3.

REASON FOR APPARENT VIOLATION

Dresden Station accepts the violation. The design basis hot short condition was defined and evaluated in the Dresden Safe Shutdown Analysis (SSA). The consequences of a valve failure due to a fire was limited to the valve mispositioning to an undesired position (e.g., the valve fails in the open or closed position). The Dresden SSA was approved in January 1983.

CORRECTIVE ACTION TAKEN AND RESULTS ACHIEVED

Dresden Station installed modifications to ensure that the hot short would not effect the Isolation Condenser. Additionally, Dresden Station revised SSD procedures to ensure that if a hot short occurred in the Reactor Water Cleanup System, a non-motor operated valve was closed to ensure isolation. Full compliance is achieved.

ACTIONS TO PREVENT FURTHER OCCURRENCE

No further actions are required since the vulnerability of SSD MOV's to the adverse affects of fire induced hot shorts on SSD have been eliminated.

DATE WHEN FULL COMPLIANCE WILL BE MET

Dresden is currently in full compliance.

ATTACHMENT B (Page 2 of 2)
ESK-96-224

Response to An Apparent Violation in Inspection Report Nos. 50-237/96012(DRS); 50-249/96012(DRS);50-254/96016(DRS);50-265/96016(DRS)
For Dresden Station

REPORTABILITY

The Referenced Inspection Report requested ComEd to discuss the basis for Dresden's decision to not report the hot short issue once it was identified as a valid technical concern. Dresden did not report the condition because the concern was not considered safety significant due to the low probability of the event, the low number of valves requiring modification (three per unit), and the provisions of redundant safe shutdown systems in the event of a fire in the control room (e.g., High Pressure Coolant Injection (HPCI) and the Isolation Condenser).

ATTACHMENT C (Page 1 of 3)
ESK-96-224

Response to the Request for Additional Information
Inspection Report Numbers 50-237/96012(DRS);
50-249/96012(DRS); 50-254/96016(DRS); 50-265/96016(DRS)

RESOURCE ALLOCATION

The consequences of a valve spuriously actuating due to fire was limited to the functional failure state of a valve mispositioning to an undesired position and failing in that position. The Dresden SSA was approved in January 1983. The Quad Cities SSA was approved in December 1982. Valve damage resulting from hot shorts was not considered.

In 1992, IEN 92-18 was issued to inform licensees of the potential for mechanical valve damage resulting from fire induced hot shorts. ComEd concluded that the impact was minimal due to the low probability of a control room fire and valve damage from fire induced hot shorts.

In June 1996, as a result of increased corporate oversight, ComEd recognized that its past actions with respect to this issue did not address the consequences of spurious valve actuation and potential valve damage caused by a postulated "hot short". Specifically, ComEd revisited the concerns outlined in IEN 92-18 and recognized that thermal overload protection would not preclude mechanical damage for all motor operated valve control circuits. IEN 92-18 alerted licensees that under certain conditions, a postulated control room fire could result in a loss of capability to maintain the reactor in a safe shutdown condition. Assuming the postulated event occurs (i.e., a design basis fire with a hot short that leads to mechanical valve damage), safe shutdown may not be assured. As a result, all six (6) sites were directed to re-evaluate their original IEN 92-18 response.

In July 1996, after each site reviewed their original IEN 92-18 responses, ComEd Engineering classified the concern as a technical issue requiring resolution. Corporate fire protection worked with site engineers to develop a generic action plan for resolving the issue. Site specific action plans were then developed and implemented. As a result, the issue of a fire induced "hot short" resulting in spurious actuation with valve damage was aggressively pursued, and conservative actions were implemented. For Dresden and Quad Cities, this action included control circuit modifications to certain motor operated valves which are critical for assuring safe shutdown capability. These modifications were completed prior to returning the units to service.

ComEd now has addressed the merits of the technical issue and taken action prior to startup of both the Dresden and Quad Cities Stations. Prior to 1996, ComEd historically took the position that for Appendix R compliance, the consequences of a valve spuriously operating due to fire was limited to the valve mispositioning to an undesired position (e.g., valve fails opened or closed) and that the probability for valve mechanical damage was sufficiently low. This does not impact our decision in recent months to address and resolve the technical issue.

ATTACHMENT C (Page 2 of 3)
ESK-96-224

Response to the Request for Additional Information
Inspection Report Numbers 50-237/96012(DRS);
50-249/96012(DRS); 50-254/96016(DRS); 50-265/96016(DRS)

MITIGATION FACTORS

A. Self-Identification

ComEd self-identified and resolved the technical issue related to hot shorts prior to returning the Dresden and Quad Cities units to service. This specific technical issue was not considered during initial design.

The failure to modify the motor operated valve circuits in a more timely manner was a result of a lack of sensitivity to the specific hot short technical concern now at issue. Since that time, ComEd Corporate Engineering has instituted oversight and assessment policies to increase the sensitivity to fire protection issues which led to the re-evaluation IEN 92-18.

B. Conservative Recommendations

This issue is an example of how the corporate engineering staff and the site engineering staffs are working together. It is this cooperation between organizations that identified the issue and initiated the recent consistent conservative review of the issue of hot shorts at all of the ComEd stations.

C. Safety Significance

Safe Shutdown in the unlikely event of a design basis fire occurring at Dresden is assured by a defense in depth approach to fire protection, including administrative controls and procedures to prevent fires, rapid detection and suppression systems, and containment of fires that spread unsuppressed for an extended period of time. However, in the unlikely event of a design basis fire, the hot short issue has the potential to pose a safety concern. For this reason corrective actions, including design changes to ensure systems important to safe shutdown will remain available during a postulated design basis fire event, were taken.

Safe Shutdown in the unlikely event of a design basis fire occurring at Quad Cities is assured by a defense in depth approach to fire protection, including administrative controls and procedures to prevent fires, rapid detection and suppression systems, and containment of fires that spread unsuppressed for an extended period of time. However, in the unlikely event of a design basis fire, the hot short issue is a safety concern. Prior to these design changes, in the absence of operator mitigating actions, a design basis fire could have resulted in mechanical valve damage such that SSD could not be achieved as written in the SSD procedures.

ATTACHMENT C (Page 3 of 3)
ESK-96-224

Response to the Request for Additional Information
Inspection Report Numbers 50-237/96012(DRS);
50-249/96012(DRS); 50-254/96016(DRS); 50-265/96016(DRS)

Although ComEd believes that the overall safety significance was low due to the low probability for a hot short condition leading to mechanical damage, ComEd has taken corrective action based on the consequences of such a failure.

CONCLUSION

ComEd acknowledges that the concern involves a valid technical issue, and has conservatively acted to resolve the issue.

ComEd

December 20, 1996

U. S. Nuclear Regulatory Commission
Attn. Document Control Desk
Washington, D. C. 20555

SUBJECT: Supplemental Response to An Apparent Violation in Inspection Report Nos. 50-237/96012(DRS); 50-249/96012(DRS);50-254/96016(DRS);50-265/96016(DRS) Protection of Motor Operated Valves During Postulated Hot Shorts NRC Docket Nos. 50-237/249 and 50-254/265

REFERENCE.

1. NRC Inspection Report Nos. 50-237/96012(DRS); 50-249/96012(DRS);50-254/96016(DRS);50-265/96016(DRS), dated November 14, 1996.

2. E. S. Kraft letter (ESK-96-224) to USNRC, Response to an Apparent Violation, dated December 12, 1996.

The Reference (1) Inspection Report discusses the results of the NRC staff's special inspection regarding fire protection issues at Dresden and Quad Cities. In the Inspection Report, the NRC staff identified one apparent violation that is being considered for escalated enforcement action for Dresden and Quad Cities. The apparent violation identifies a concern with the protection of motor operated valves during a postulated control room fire leading to a "hot short". Under certain limited conditions, a fire induced hot short in the control circuit of a motor operated valve can lead to spurious valve operation and mechanical damage to the valve operator.

Also in this Inspection Report, the NRC staff requested that ComEd include a discussion of assurances that other nonconforming conditions do not exist at any of our other nuclear power plants, and that site and/or corporate engineers are providing conservative recommendations to station management when addressing nonconforming conditions.

Reference 2 provided the response to the apparent violation for Dresden and Quad Cities stations. The discussion with respect to other ComEd plants, including long term corrective actions and interim compensatory measures, may be found in Attachment A.

ComEd appreciates the opportunity to respond to these concerns. If there are any further questions regarding this issue, please contact Roger Gavankar at Downers Grove.

Sincerely,

John B. Hosmer

John B. Hosmer
Engineering Vice President
Downers Grove

Attachment: A - Discussion with Respect to Other ComEd Plants

cc: A. B. Beach, Regional Administrator - RIII
C. L. Vandemiet, Senior Resident Inspector - Dresden
C. G. Miller, Senior Resident Inspector - Quad Cities
R. A. Capra, Project Directorate - NRR
J. F. Stang, Project Manager - NRR
R. M. Pulsifer, Project Manager - NRR
Office of Nuclear Facility Safety - IDNS

ATTACHMENT A

Response to the Request for Additional Information Inspection Report Numbers 50-237/96012(DRS); 50-249/96012(DRS); 50-254/96016(DRS); 50-265/96016(DRS)

Discussion of Other ComEd Plants

BACKGROUND

In 1992, IEN 92-18 was issued to inform licensees of the potential for mechanical valve damage resulting from fire induced hot shorts. The IEN correctly stated that the information contained in the notice was not an original license requirement. Consistent with the industry positions at that time, ComEd sites concluded that no specific actions were required due to one or more of the following reasons:

a. Initial concurrence with the August 13, 1992, Nuclear Management and Resources Council (NUMARC) recommendation regarding careful consideration by utility management of any plans for plant design changes with respect to IEN 92-18.

b. The premise that thermal overload protection would preclude mechanical damage.

c. Low probability of a control room fire <u>and</u> valve damage from fire induced hot shorts.

In June 1996, due to increased corporate engineering oversight, ComEd recognized that its past actions with respect to this issue did not address the "consequences" of spurious valve actuation and potential valve damage caused by a postulated "hot short". Specifically, ComEd revisited the concerns outlined in IEN 92-18 and recognized that, contrary to the suggestion in IEN 92-18, thermal overload protection would not preclude mechanical damage for all motor operated valve control circuits, and that dismissing the concern to low probability at some sites did not assure safe shutdown. Assuming the postulated event occurs (e.g, a design basis control room fire with a hot short that leads to mechanical valve damage), safe shutdown could be compromised. As a result, all six (6) sites were directed to re-evaluate their original IEN 92-18 response.

In July 1996, after each site reviewed their original IEN 92-18 responses, ComEd engineering classified the concern as a technical issue requiring resolution. Corporate fire protection worked with site engineers to develop a generic action plan for resolving the issue. Site specific action plans were then developed and are being implemented. As a result, the issue of a fire induced hot short resulting in spurious actuation with valve damage was aggressively pursued, and conservative interim compensatory actions are implemented for units at power operation if it is determined that mechanical damage could complicate or prevent safe shutdown.

Interim compensatc neasures include increasing awareness ˜control room personnel by informing them of the potential condition and necessary mitigating actions (e.g., establishing alternate flow paths or isolations), and prohibiting conditions that increase the probability of a control room fire (e.g., hot work, transient combustibles that are not integral to plant operation). These actions further minimize the probability of a fire in the control room, and provide reasonable assurance that safe shutdown will be achieved, until long term corrective actions are complete (e.g., procedure enhancements, modifications, training).

DESIGN BASIS

ComEd concurs that "hot shorts" with possible mechanical damage to the valve is a valid technical issue, and we have taken action at each site to minimize its impact. However, ComEd does not believe this issue was part of our original design basis analyses. In our safe shutdown analyses (SSA), the consequences of a valve spuriously actuating due to fire was limited to the functional failure state of a valve mispositioning to an undesired position (e.g., valve fails open or closed). Postulating hot shorts that cause mechanical damage and preclude manual operation of a valve was not a failure state considered in the original design basis analyses. These analyses, and the approach to consideration of spurious valve operation, were consistent with the industry and subsequent guidance provided in Generic Letter 86-10, "Implementation of Fire Protection Requirements." The approval of these analyses confirm that our initial approach with respect to spurious valve actuation satisfied Appendix R requirements.

PLANT STATUS

- Dresden / Quad:

  Re-review of IEN 92-18 is complete. Corrective actions completed to adequately mitigate the concern outlined in IEN 92-18 were provided in Reference 1.

- LaSalle:

  Re-review of IEN 92-18 is complete. Long term corrective actions to adequately mitigate the concern outlined in IEN 92-18 (e.g., circuit modifications) are scheduled to be completed prior to restart of Unit 1 and Unit 2, respectively.

- **Zion:**

  Re-review of IEN 92-18 is complete. MOV's were screened out in cases where mechanical damage is precluded by administratively isolating the MOV circuit during power operation (e.g., 480 vac power is turned off). The circuits for the remaining MOV's were reviewed. To date, no circuit modifications are required because the MOV circuits are not susceptible to the hot short concern. Formal documentation of the re-review is expected to be completed by January 31, 1997.

- Byron / Braidwood:

Re-review of IEN 92-18 is complete. The concern outlined in IEN 92-18 will not prevent safe shutdown. However, in order to ensure the safe and conservative operation of the plants, and to enhance the capability to respond to the postulated events, procedure revisions are being evaluated and implemented. Procedure changes are desirable to enhance the ability of the operators to diagnose and respond to the event postulated in IEN 92-18 in the event of a control room fire, but are not essential to achieve safe shutdown of the units. Procedure changes will be implemented in a timely manner. During the interim, until the procedure revisions are complete, compensatory measures include heightening operator awareness of mitigating actions via tailgate sessions, and prohibiting conditions that increase the probability of a fire in the control room (e.g., hot work, transient combustibles).

In addition, even though the postulated event is considered to be outside the design and licensing basis of the Byron/Braidwood stations, modifications are being evaluated. Modifications, if implemented, would be for the purpose of enhancing continued safe and conservative operation of the units.

CONCLUSION

ComEd acknowledges that the concern involves a valid technical issue, and has conservatively acted to resolve the issue. While consideration of mechanical damage as a result of hot shorts was outside the original design and licensing basis of the plant, ComEd is addressing the merits of the technical issue at each site.

Several licensees, including ComEd, historically took the position that for Appendix R compliance, the consequences of a valve spuriously operating due to fire was limited to the valve mispositioning to an undesired position (e.g., valve fails opened or closed). This does not impact our decision in recent months to address and resolve the technical issue. However, ComEd believes that the matter should be addressed consistently as a resolution of a generic industry issue.

:1400 Opus Place
Downers Grove, IL 6051 '01

March 6, 1997

ComEd

U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Attention: Document Control Desk

Subject: Byron Station Units 1 and 2
Braidwood Station Units 1 and 2
Dresden Station Units 2 and 3
LaSalle Co. Station Units 1 and 2
Quad Cities Station Units 1 and 2
Zion Station Units 1 and 2
Protection of Motor Operated Valves During Postulated Hot Shorts
NRC Docket Nos. 50-237, 249, 254, 265, 295, 304, 373, 374, 454, 455, 456 and 457

References:

1. NRC Inspection Report Nos. 50-237/96012 (DRS); 50-237/96012 (DRS); 50-254/96016 (DRS); 50-265/96016 (DRS), dated November 14, 1996.

2. E.S. Kraft letter (ESK-96-224) to USNRC, Response to an Apparent Violation, dated December 12, 1996.

3. J. B. Hosmer letter to USNRC, Supplemental Response to Apparent Violation, dated December 20, 1996.

4. Letter 96-016-00 for LaSalle Co.

Reference (2) provided the response to the apparent violation for Dresden and Quad Cities Stations, described in reference (1), a concern with a postulated control room fire induced "hot short" in a motor operated valve circuit. Reference (3) described the status and corrective actions being taken for this issue at the other ComEd stations.

Based on questions received from the NRC staff, the purpose of this letter is to clarify the ComEd position with respect to the actions taken to address IN 92-18, and how the contents of the Information Notice impact each stations' ability to achieve safe shutdown in accordance 10CFR50, Appendix R.

A Unicom Company

The completed ComEd re-reviews show, when postulating the event in IN 92-18, that Byron, Braidwood and Zion were always able to achieve a safe shutdown condition in accordance with their respective SSA. Dresden would be able to achieve a safe shutdown condition in accordance with their respective SSA, in all but one condition. At Dresden, if a hot short causes a spurious actuation of the Isolation Condenser isolation valve in the closed position, the valve may be damaged in that position due to the increased closing torque value established to assure valve closure as required by the GL 89-10 program. With a fire in the control room, station procedures require deenergizing the HPCI system by pulling fuses and opening circuit breakers to provide load shedding. With a damaged Isolation Condenser valve and a deenergized HPCI system, both safe shutdown paths would not be available, until the HPCI system is reenergized.

For Quad Cities, as stated in reference (2) and LaSalle, as stated in reference (4), postulating the event described in IN 92-18 would compromise achieving safe shutdown as described in the plant specific SSAs.

If there are any further questions regarding this issue, please contact me at the Downers Grove office.

Sincerely,

John B. Hosmer
Engineering Vice President
Downers Grove

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cc: A. Beach, Regional Administrator - RIII
R. Capra, Director of Directorate III-2, NRR
G. Dick, Byron Project Manager, NRR
R. Assa, Braidwood Project Manager, NRR
J. Stang, Dresden Project Manager, NRR
D. Skay, LaSalle Project Manager, NRR
R. Pulsifer, Quad Cities Project Manager, NRR
C. Shiraki, Zion Project Manager, NRR
C. Phillips, Senior Resident Inspector (Braidwood)
S. Burgess, Senior Resident Inspector (Byron)
C. Vandemiet, Senior Resident Inspector (Dresden)
M. Huber, Senior Resident Inspector (LaSalle)
C. Miller, Senior Resident Inspector (Quad Cities)
R. Westberg, Acting Senior Resident Inspector (Zion)
Office of Nuclear Facility Safety - IDNS

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
801 WARRENVILLE ROAD
LISLE, ILLINOIS 60532-4351

December 30, 1997

EAs 96-388, 96-389,
and 96-390

Mr. O. Kingsley
President, Nuclear Generation Group
and Chief Nuclear Officer
Commonwealth Edison Company
Executive Towers West III
1400 Opus Place, Suite 300
Downers Grove, IL 60515

SUBJECT: EXERCISE OF ENFORCEMENT DISCRETION (NRC INSPECTION REPORTS 50-237/96012(DRS); 50-249/96012(DRS); 50-254/96016(DRS); AND 50-265/96016(DRS))

Dear Mr. Kingsley:

This refers to a fire protection inspection conducted from July 8 through October 17, 1996, at the Commonwealth Edison Company's (ComEd) Dresden and Quad Cities nuclear stations. An apparent violation was identified during the inspection. This apparent violation concerned the failure to protect motor operated valves (MOVs) from the effects of hot shorts during a postulated control room fire. The report documenting the inspection was sent to ComEd by letter dated November 14, 1996.

During May 1996, employees at the Quad Cities Station learned of the potential inability to reposition MOVs following a postulated control room fire, and subsequently notified personnel at the Dresden Station. On July 8, 1996, ComEd notified the NRC in a report made pursuant to 10 CFR 50.72. ComEd issued a Licensee Event Report on August 6, 1996. Based on the information provided in the ComEd reports, information developed during the inspection, and provided by ComEd on December 12 and 20, 1996, in response to the inspection report, the NRC has determined that a violation of NRC requirements occurred. The violation concerned the failure of ComEd to provide adequate protection to ensure operation of equipment for systems necessary to achieve and maintain hot shutdown conditions, or to maintain a dedicated safe shutdown capability.

In its December 1996 submittals, ComEd agreed with the violation; however, ComEd indicated that the issue with "hot shorts" was not a part of the original design basis. ComEd asserted that its safe shutdown analyses satisfied the requirements of 10 CFR Part 50, Appendix R, and the consideration within those analyses of the consequence of a spurious valve actuation due to fire was limited to mispositioning a valve to an undesired position, and did not include possible mechanical damage to the valve.

The NRC disagrees with the ComEd position. Consistent in NRC requirements and guidance to the industry has been the requirement for licensees to demonstrate that fire induced failures from "hot shorts" will not prevent operation, or cause maloperation of the alternative or dedicated shutdown method. This guidance was communicated in Generic Letter 81-12, "Fire Protection Rule" and Generic Letter 86-10, "Implementation of Fire Protection Requirements." This issue involved MOVs that were potentially unable to perform the post-fire, safe shutdown functions in accordance with 10 CFR Part 50, Appendix R, Section III.G, because the control circuits were susceptible to fire induced "hot shorts." This design issue is a violation of 10 CFR Part 50, Appendix R, and represents a failure to ensure that a redundant train of safe shutdown equipment would remain free from fire damage and available to maintain a unit in "hot shutdown." The violation is safety significant because the potential existed for each unit to not be able to achieve a safe shutdown condition for a control room fire.

This matter was considered for escalated enforcement and a possible civil penalty. However, after consultation with the Director, Office of Enforcement, I have been authorized to neither issue a Notice of Violation, nor propose a civil penalty in this case, in accordance with Section VII.B.3 of the General Statement of Policy and Procedures for NRC Enforcement Actions, "Enforcement Policy," NUREG-1600. This decision was made after considering that this issue was discovered by the ComEd staff, and would not have likely been identified by routine efforts. The initial evaluation performed by the ComEd staff of NRC Information Notice (IN) 92-18, "Potential for Loss of Remote Shutdown Capability During a Control Room Fire," determined that an unanalyzed condition did not exist, and the installed MOV thermo-overloads provided adequate protection at both the Dresden and Quad Cities stations. However, during May 1996, ComEd identified that MOVs were susceptible to "hot short" induced mechanical damage. ComEd's understanding of Appendix R requirements, and reliance on a 1992 recommendation from the Nuclear Management and Resources Council (NUMARC), which was not endorsed by the NRC, may have caused confusion during the ComEd evaluation of IN 92-18. The NRC, therefore, has credited ComEd with the identification of the violation. The NRC also considered that ComEd's corrective actions, following identification of the issue during May 1996 were appropriate. These corrective actions included modifications for all affected equipment. The NRC also considered that this issue was not reasonably linked to current performance. The exercise of enforcement discretion recognizes ComEd's efforts in identifying and correcting a significant design problem.

The NRC has concluded that information regarding the reason for the violation, the corrective actions taken, plans to correct the violation and prevent recurrence, and the date when full compliance was achieved is already adequately addressed on the docket in Inspection Reports 50-237/96012(DRS), 50-249/96012(DRS), 50-254/96016(DRS) and 50-265/96016(DRS), and your responses dated December 12 and 20, 1996. Therefore, you are not required to respond to this letter unless the description therein does not accurately reflect your corrective actions or your position. In that case, or if you choose to provide additional information, your correspondence should be sent to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator, NRC Region III, 801 Warrenville Road, Lisle, IL 60532-4351, and a copy to the NRC Resident Inspector at the Dresden and Quad Cities Stations.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter will be placed in the NRC Public Document Room (PDR).

Sincerely,

A. Bill Beach
Regional Administrator

Docket Nos. 50-237; 50-249;
50-254; and 50-265
License Nos. DPR-19; DPR-25;
DPR-29; and DPR-30

cc: M. Wallace, Senior Vice President
Corporate Support
D. A. Sager, Vice President,
Generation Support
E. Kraft, Vice President, BWR Operations
J. S. Perry, Site Vice President - Dresden
L. W. Pearce, Site Vice President - Quad Cities
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HBell, OIG
GCaputo, OI
TMartin, AEOD
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PAO:RIII
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DRP
Docket File

TAB 21

DRESDEN 2&3

FIRE PROTECTION REPORT

Inspection Report Nos. 50-237/97021 and 50-249/97021

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
801 WARRENVILLE ROAD
LISLE, ILLINOIS 60532-4351

March 6, 1998

EA 98-122

Mr. Oliver D. Kingsley
President, Nuclear Generation Group
Commonwealth Edison Company
ATTN: Regulatory Services
Executive Towers West III
1400 Opus Place, Suite 500
Downers Grove, IL 60515

SUBJECT: NRC INSPECTION REPORT 50-237/97021(DRS); 50-249/97021(DRS) AND NOTICE OF VIOLATION

Dear Mr. Kingsley:

This letter refers to the inspection conducted on October 21, 1997 through January 27, 1998, at the Dresden Nuclear facility. The purpose of the inspection was to evaluate the effectiveness of your engineering organization in performing routine and reactive site activities, including controls for the identification, resolution and prevention of technical issues and problems that could degrade the quality of plant operations or safety. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Overall, the inspection determined that your engineering staff was effective in the identification and resolution of technical issues. Self-assessments exhibited a pro-active trend in the attempt to disclose performance problems within the engineering organization. The quality of engineering reviews were in most cases technically sound. As a result, we have concluded that all commitments and corrective actions identified by Confirmatory Action Letter (CAL) No. RIII-96-016, dated November 21, 1996, including those activities associated with the Dresden Engineering Assurance Group (DEAG) have satisfied NRC requirements. The CAL was closed.

Based on the results of this inspection, the NRC has determined that three violations of NRC requirements occurred. The first violation identified that a written safety evaluation had not been performed when a prior inadvertent change to the control room ventilation system design deleted the automatic smoke purge mode transfer capability. The second violation identified that the Fire Protection Report had not been updated and submitted to the NRC for approximately three years. The third violation identified that the fire protection pre-plans had not been updated for approximately five years. The three violations were of concern because they involved the fire protection program and were related to an inadequate awareness of fire protection program requirements.

These violations are cited in the enclosed Notice of Violation (Notice), and the circumstances surrounding the violations are described in detail in the subject inspection report. Please note that you are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response will be placed in the NRC Public Document Room.

We will gladly discuss any questions you have concerning these inspections.

Sincerely,

John A. Grobe, Director
Division of Reactor Safety

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

Enclosures:
1. Notice of Violation
2. Inspection Report 50-237/97021(DRS); 50-249/97021(DRS)

cc w/encls:
M. Wallace, Senior Vice President
D. Helwig, Senior Vice President
G. Stanley, PWR Vice President
J. Perry, BWR Vice President
D. Farrar, Regulatory Services Manager
I. Johnson, Licensing Director
DCD - Licensing
M. Heffley, Site Vice President
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F. Spangenberg, Regulatory Assurance Manager
Richard Hubbard
Nathan Schloss, Economist Office of the Attorney General
State Liaison Officer
Chairman, Illinois Commerce Commission

NOTICE OF VIOLATION

Commonwealth Edison Company
Dresden Station, Units 2 and 3

Docket Nos. 50-237; 50-249
License Nos. DPR-19; DPR-25
EA 98-122

During a Nuclear Regulatory Commission (NRC) inspection conducted on October 21, 1997 through January 27, 1998, three violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, the violations are listed below:

1. 10 CFR 50.59 permits the licensee, in part, to make changes to the facility, and procedures, as described in the safety analysis report, without prior Commission approval, provided the changes do not involve an unreviewed safety question (USQ). Records of these changes must include a written safety evaluation which provides the bases for the determination that the changes do not involve an USQ.

   Prior to March 22, 1996, the Dresden Updated Final Safety Analysis Report, Sections 6.4.2 and 6.4.4.3, in part, stated that for fire and smoke protection, the control room heating, ventilation, and air conditioning (HVAC) system was designed to isolate and maintain the design conditions within the control room during fires. The control room Train A HVAC system was capable of both automatic and manual transfer from the normal operating mode to the smoke purge mode. Automatic transfer to the smoke purge mode was initiated by smoke detectors, located in the control room return air ducts.

   Contrary to the above, in November 1994, the licensee identified that a prior inadvertent change to the Dresden Station's control room ventilation system design deleted the automatic smoke purge mode transfer capability. From November 1994 to March 1996, the licensee failed to perform a written safety evaluation to provide the bases for the determination that the change did not involve an USQ.
   (VIO 50-237/249-97021-02(DRS))

   This is a Severity Level IV violation (Supplement 1).

2. 10 CFR 50.71(e) states, in part, that the licensee shall submit revisions containing updated information to the Final Safety Analysis Report (UFSAR) to the NRC annually or six months after each refueling outage provided the interval between successive updates does not exceed 24 months.

   Contrary to the above, from November 1994 through November 21, 1997, the Fire Protection Report, referenced as part of the UFSAR, had not been updated and the required revision updates submitted to the NRC. (VIO 50-237/249-97021-03(DRS))

   This is a Severity Level IV violation (Supplement 1).

3. Technical Specification 6.2.A states, in part, that written procedures shall be established and implemented covering the activities referenced in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, dated February 1978. The activities listed in RG 1.33 included procedure review and the approval process.

   Dresden Fire Protection Program Procedure (DFPP) 4100-01, "Fire Protection Program," Revision 1, Section G.2.a.(7) required that fire pre-plans be reviewed on an annual basis, and revised as appropriate.

   Contrary to the above, as of November 21, 1997, the fire pre-plans had not been reviewed or revised since September 1992. (VIO 50-237/249-97021-04(DRS))

   This is a Severity Level IV violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, Commonwealth Edison Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with a copy to the Regional Administrator, Region III, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be placed in the NRC Public Document Room (PDR), to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be placed in the PDR without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you <u>must</u> specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.790 (b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated at Lisle, Illinois
this 6th day of March 1998

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-237; 50-249
License Nos:	DPR-19; DPR-25
Report No:	50-237/97021(DRS)
Report No:	50-249/97021(DRS)
Licensee:	Commonwealth Edison Company
Facility:	Dresden Generating Station, Units 2 and 3
Location:	6500 North Dresden Road Morris, IL 60450-9765
Dates:	October 21, 1997 through January 27, 1998
Inspectors:	George M. Hausman, Reactor Inspector Gerry F. O'Dwyer, Reactor Inspector Darrell L. Schrum, Reactor Inspector Tom Tella, Reactor Inspector
Approved by:	Ronald N. Gardner, Chief Engineering Specialists Branch 2 Division of Reactor Safety

EXECUTIVE SUMMARY

Dresden Generating Station, Units 2 and 3
NRC Inspection Report 50-237/97021(DRS); 50-249/97021(DRS)

An announced core inspection that reviewed the engineering and technical support (E&TS) organization's effectiveness in the performance of routine and reactive site activities including identification and resolution of technical issues and problems. As a result of the inspection, three violations (VIOs) of Nuclear Regulatory Commission (NRC) requirements were identified and one unresolved item (URI) was issued.

- Overall the inspection concluded that the engineering staff was effective in the identification and resolution of technical issues. Self-assessments exhibited a pro-active trend in the attempt to disclose performance problems within the engineering organization. The quality of engineering activities was in most cases technically sound. (Section All)

- The team had concerns that the UFSAR did not accurately characterize the plant's design-basis or the plant's capability to respond to a potential Dresden Lock and Dam failure. As a result, the team concluded that further review by the licensee and NRC was required. An NRC URI was initiated to document these concerns. (Section E3.4; URI 50-237/249-97021-01(DRS))

- The team concluded that all commitments and corrective actions identified by Confirmatory Action Letter (CAL) No. RIII-96-016, dated November 21, 1996, including those activities associated with the Dresden Engineering Assurance Group (DEAG) have satisfied NRC requirements. The CAL was closed. (Section E6).

- In November 1994, the licensee identified that a prior inadvertent change to the Dresden Station's control room ventilation system design deleted the automatic smoke purge mode transfer capability. From November 1994 to March 1996, the licensee failed to perform a written safety evaluation to provide the bases for the determination that the change did not involve an unreviewed safety question. (Section F2; VIO 50-237/249-97021-02(DRS))

- From November 1994 through November 21, 1997, the Fire Protection Report, referenced as part of the UFSAR, had not been updated and the required revision updates submitted to the NRC. (Section F3; VIO 50-237/249-97021-03(DRS))

- As of November 21, 1997, the fire pre-plans had not been updated since September 1992. (Section F3; VIO 50-237/249-97021-04(DRS))

Report Details

III. Engineering

E1 Conduct of Engineering

E1.1 Performance and Effectiveness

a. Inspection Scope (IP37550; IP40500)

The purpose of the inspection was to evaluate the effectiveness of the E&TS organization in the performance of routine and reactive site activities including identification and resolution of technical issues and problems. The inspection focused on system engineering functions, modifications, technical problem resolution, and engineering support to other plant organizations. In addition, the licensee's corrective action process was evaluated.

The criteria used to assess the E&TS performance was quality of technical work produced, understanding of plant design, and active involvement in preventing and solving plant problems.

b. Observations and Findings

Overall, the engineering staff was effective in the identification and resolution of technical issues. The inspection showed engineers to be knowledgeable and involved with the work conducted in their respective areas of responsibility. Engineers and immediate supervisors were cognizant of the current status of assigned systems and components, as well as, recent problems and deficiencies that had been identified. The quality of the reviews conducted by the engineering staff was in most cases technically sound. However, minor discrepancies were observed in many of the engineering products and activities. These discrepancies indicated that the licensee's engineering staff should be thorough and exhibit more attention to detail. The DEAG reviews were in most cases thorough and technically sound. However, the team was concerned that many DEAG members were no longer employed at the Dresden site and such loss of experienced personnel might degrade the licensee's ability to maintain an improving trend in engineering performance.

c. Conclusions

The inspection team concluded that conduct of engineering was satisfactory.

E1.2 Problem Identification and Root Cause Determination

a. Inspection Scope (IP37550; IP40500)

The team reviewed several PIFs generated by the plant staff and verified whether the PIFs were properly processed for root cause determination and corrective actions.

b. Observations and Findings

The team reviewed selected PIFs for adequate description of the problem and to verify whether the PIFs were properly prioritized and followed up as necessary. The team also reviewed whether the PIFs were reviewed for root cause determination and corrective actions when required. A nuclear tracking system (NTS) number was assigned to follow up PIFs. The team reviewed a few NTS items to verify whether they were adequately followed up by the licensee for completion. The team noticed that the reasons for NTS due date extensions were not always adequately justified. An example was PIF 97-12037 dated January 30, 1997, regarding allowable battery temperatures. This PIF was tracked by NTS Item 237-201-97-12001. The reason for extending this NTS item for about five months was "to provide new DC system engineer time to evaluate other options."

The team attended a PIF screening meeting on November 3, 1997. The team noted that the department managers/supervisors were present as necessary. The PIFs received were adequately discussed and assigned to the responsible departments for further follow up.

c. Conclusion

The team concluded that a low threshold exists for generation of PIFs. The team observed that the PIFs were promptly processed and assigned to a department for follow up. The root causes for important PIFs were identified for further corrective actions. However, adequate justification was not always provided for extending corrective action due dates.

E2 Engineering Support of Facilities and Equipment

E2.1 4kV Breaker Auxiliary Switch Failures

a. Inspection Scope (IP 37550; IP40500)

The team reviewed the licensee's corrective actions for Merlin-Gerin 4.1kV breaker auxiliary switch failures.

b. Observations and Findings

The licensee's corrective actions involved the installation of nylon tie-wraps around the breaker's auxiliary switches. The auxiliary switches on the breakers were made of a phenolic material and were observed to develop cracks at the Dresden and Quad Cities Stations.

The manufacturer and the local distributor of the breakers, Pacific Breaker Systems, Inc. and Golden Gate Switchboard Co., were informed of the defects. A 10 CFR Part 21 notification was issued by Golden Gate Switchboard Co. on April 11, 1997, regarding the cracking and breakage of the circuit breaker auxiliary switches in the mounting area.

The cracking and breakage in the mounting area resulted in unacceptable contact resistance readings.

The licensee developed a temporary fix that used nylon tie-wraps around the two auxiliary switches on each breaker and qualified the fix for a period of 18 months. The qualification test was performed by testing the breaker for 225 cycles and performing a seismic test at Wyle Laboratories. The Plant Operations Review Committee approved the modification for only one plant operating cycle.

The team noted that the root cause(s) for the failure of the auxiliary switches had not been identified by the manufacturer. Potential corrective actions, such as a change in the type of switch material, had not been provided to the licensee.

However, the licensee performed a root cause evaluation during August 1997, which concluded that the primary root cause(s) for the failures were a design weakness in the auxiliary switch mounting and inappropriate torque values for the mounting T-bolts. The evaluation led to the licensee's immediate corrective action of using nylon tie-wraps around the auxiliary switches.

For a semi-permanent fix, the licensee intended to qualify the nylon tie-wraps for a period of six years. The breakers were tested with the nylon tie-wraps for 750 cycles at Commonwealth Edison Company's (ComEd's) C-Team facility and seismically qualified at the Wyle Lab for six years. The licensee intended to use stainless steel U-bolts (in place of the tie-wraps) as a permanent fix.

The licensee's root cause evaluation indicated that the original design created tensile forces where the phenolic material was not sufficiently strong.. The team noted that the tie-wraps had reduced the tensile forces to some extent; however, the licensee's root cause effort did not address the weakness of the switch material and the potential need to change to an alternate (stronger) material that could withstand the higher tensile forces.

The team expressed concern that the tie-wrapped auxiliary switches were considered for extended use, prior to the completion of the manufacturer's root cause evaluation and without considering an alternate material. The team considered the potential for cracking the auxiliary switches during operation remained even with the tie-wraps or U-bolts in place.

c. Conclusion

The licensee's actions to temporarily extend the life of the auxiliary switches with nylon tie-wraps were acceptable. However, the licensee's and vendor's failure to address the weakness of the phenolic material and not considering an alternate (stronger) material for the auxiliary switches was considered a weakness.

E2.2 Plant Walkdowns

a. Inspection Scope (IP 37550)

The team walked down several areas of the plant to assess the material condition of equipment and general plant condition.

b. Observations and Findings

The team walked down the intake structure and some electrical areas, such as the diesel generators, switchgear areas, and battery rooms.

The areas walked down were generally kept clean. The equipment observed, such as safety-related batteries, diesel generators and safety-related electrical switchgear were maintained in good condition.

c. Conclusions

The team concluded that the plant areas walked down were well maintained and no deficiencies were observed.

E3 Engineering Procedures and Documentation

E3.1 Design Change Packages, Modifications and Temporary Alterations

a. Inspection Scope (IP 37550)

The team reviewed the following design change packages (DCPs), modifications and temporary alteration (Temp Alt):

- DCP 9700202 — Install 70 Amp Breaker in Cubicle 39-2-C3
- DCP 9700207 — Change out of Control Transformers in Turbine Oil Tank Vapor Extractor Breaker
- E12-3-95-224 — Limit Switch Replacement on Motor Operated Valve (MOV) 3-205-24
- M12-0-97-001A — Auxiliary Electrical Equipment Room Heating, Ventilation, and Air Conditioning (HVAC) Modification
- M12-2-85-302 — Unit 2 - 125 Volt DC Charger Upgrades
- M12-3-96-008 — Time Delay Addition on Valve 3-2301-15
- P12-3-94-284 — Gearset Replacement on MOV 3-1501-28B
- Temp Alt III-09-97 — Install Portable Air Compressor Outside Crib House

b. Observations and Findings

The team observed that the above DCPs and modifications clearly described the proposed alterations and justifications. Each design change contained an adequate 10 CFR 50.59 screening or safety evaluation. The design issues worksheets considered several additional issues. Adequate interdepartmental reviews were performed as necessary.

The team reviewed several calculations made in support of the design changes. The calculations included acceptable assumptions and were adequately reviewed and approved. No problems were identified with the calculations.

Several work requests were reviewed that implemented the design changes. The team found that the design changes did not always include the results of post-modification testing (PMT). An example was the PMT performed for DCP E12-3-95-224 (level switch replacement on MOV 3-205-24) that was completed on June 11, 1997. The team had to obtain a copy of the completed procedure from central files to verify whether the PMT was completed.

The team observed that Temp Alt III-09-97 provided the reasons for the alteration, an adequate safety evaluation and a date for the expected removal of the alteration (five months after installation). The team's walk down of the temporary alteration found the Temp ALT installation in good condition.

c. Conclusion

The team concluded that the modifications, DCPs and temporary alteration reviewed were adequately implemented. However, some DCPs did not include PMT results.

E3.3 Calculations/Evaluation

a. Inspection Scope (IP 37550)

The team reviewed the following calculations/evaluation and associated DEAG reviews:

- Calculation DRE 97-0171, "Determination of Acceptance Criteria for CCSW One and Two Pump NPSH Testing - Units 2 & 3," Revision 0

- Calculation DRE 97-0172, "Vortexing at CCSW Intakes - Units 2 & 3," Revision 0

- Document ID # 5543459, "Evaluation, Re: Low Pressure Coolant Injection (LPCI) System, Hydraulic Calculation for Containment Cooling and Containment Cooling Spray Modes," dated October 29, 1997

b. Observations and Findings

Calculation DRE 97-0171:

The team observed that the calculation used the pump suction centerline as the pump datum plane.

The team determined that this method of calculation was non-conservative and introduced an error into the calculation. The team's assessment of the DEAG review identified that the DEAG did not detect this error, but did note conservatism in the calculation. The team determined that the conservatism compensated for the non-conservative error.

The team observed that not all of the logic thought processes and equation derivations were documented in the calculation, making the methodology more difficult to understand (e.g., the gage error effect was not bounded). These weaknesses indicated a need for more attention to detail. The DEAG review recommended similar clarifications to make the calculation a better source of information for future users.

Calculation DRE 97-0172:

The Vortexing calculation stated the maximum CCSW intake flow rate was 7,200 gpm. The calculation's design input reference was the Hydraulic Institute Standards, ANSI/HI 1.3.3.6.1-1.3.3.6.3, American National Standard for Centrifugal Pumps, approved May 23, 1994.

As flow rates increase the distance between intake centerlines must be increased to prevent vortexing. The calculation identified the actual distance between the CCSW intake centerlines as 42 inches. The design input reference stated the minimum distance between the intake centerlines should be 52 inches for a 7,200 gpm flow rate and that at 42 inches the flow rate should be limited to 5,400 gpm.

Although the actual distance did not meet the design input reference's recommendation for a 7200 gpm flow rate, the calculation concluded that the distance was acceptable because the CCSW system was required to be maintained at 20 psid higher than the LPCI system. The 20 psid differential was maintained by throttling the CCSW flow rate below 7,200 gpm.

The team was concerned that the amount of throttling was not specified and given the right operating configuration, vortexing might occur due to insufficient distance between intake centerlines. In response, the licensee obtained and documented in Nuclear Design Information Transmittal (NDIT) S040-DH-0513 the vendor's confirmation that a 42 inch distance was acceptable for flows as high as 7,200 gpm. The team determined that the specific vendor statement took precedence over the general recommendation in the design input reference. Therefore, the calculation's conclusion that CCSW pump intake bay dimensions were adequate was correct. The DEAG reviewer stated the reason he did not comment on the absence of a specified maximum flow rate was that it was common knowledge within Dresden Engineering that the 20 psid restriction required throttling the CCSW flow.

Document ID # 5543459:

The 12 System Key Parameter Verification Program (LPCI System Discrepancy #4) identified that no formal hydraulic calculation existed which demonstrated that the LPCI system could provide the required 5,000 gpm flow through the containment cooling heat exchanger to ensure adequate containment cooling.

This evaluation documented that the LPCI system could provide the required flow. The capability was demonstrated primarily by Dresden Operating Surveillance (DOS) 1500-10, "LPCI System Pump Operability Test with Torus Available and Inservice Testing (IST) Program," Revision 30 and NFS-BSA-D-97-03, "Sensitivity Analysis Post-LOCA Containment Performance for Dresden Units 2/3," dated March 12, 1997. The team determined that the evaluation was technically sound.

c. Conclusions

The team concluded that the calculations and evaluation were technically sound. However, the documentation of logic employed and the common site specific knowledge used was not always evident and could have been improved with more attention to detail.

E3.4 Updated Final Safety Analysis Report

a. Inspection Scope (IP 37550)

The team reviewed sections of the UFSAR and the licensee's corrective action documentation associated with a potential Dresden Lock and Dam failure.

b. Observations and Findings

The team expressed a number of concerns with regards to the validity of some UFSAR statements contained within Section 9.2.5.3.1, "Dam Failure during Normal Operations," and Section 9.2.5.3.2, "Dam Failure Coincident with a LOCA."

The team observed that the UFSAR did not accurately characterize the plant's design-basis or the plant's capability to respond to a potential Dresden Lock and Dam failure. As a result, the team had concerns with the ability of the plant to respond to a dam failure as stated in the UFSAR.

The team's review of the licensee's "Summary of Dresden NRC Requirements for 1997," dated September 30, 1997, indicated that the licensee was aware of similar concerns, although not identical to the team's. The licensee stated that several PIFs related to this issue were in the corrective action process. The PIFs identified were:

- PIF 227A-12-1997-012788, "UFSAR Implied One CCSW Pump Operation After a Dam Failure Coincident With a LOCA," dated February 25, 1997

- PIF D1997-05554, "UFSAR CCSW Piping Statement Discrepancy" dated June 25, 1997

- PIF D1997-05955, "UFSAR LPCI Flow Timing Discrepancy," dated June 24, 1997

- PIF D1997-06487, "Incorrect Source Document Referenced for Diesel Generator Cooling Water Pump in a Calculation," dated August 27, 1997

- PIF D1997-08290, "NRC Concerns About CCSW System Performance After a Dam Failure Coincident With a LOCA," dated November 25, 1997

  This PIF was issued as a result of the team's concern that no high-point vent valves were installed to vent trapped air during the reflood of the CCSW intake bay, which was not considered by DOA-0010-01, "Dresden Lock and Dam Failure," Revision 6.

In addition, the licensee stated that an evaluation had not been completed to determine whether the Dresden Nuclear Plant Design Basis required the plant to be capable of a safe shutdown after a dam failure coincident with a Unit 2 or 3 LOCA and a loss of offsite power (LOOP).

c. Conclusions

The team had concerns that the UFSAR did not accurately characterize the plant's design-basis or the plant's capability to respond to a potential Dresden Lock and Dam failure. As a result, the team concluded that further review by the licensee and NRC was required. An NRC URI was initiated to document these concerns. (URI 50-237/249-97021-01(DRS))

E4 Engineering Staff Knowledge and Performance

a. Inspection Scope (IP 37550)

The team observed the performance of the engineering staff, interviewed both system and design engineering personnel, and walked down plant systems with some system engineers.

b. Observations and Findings

All engineers interviewed appeared to be experienced and well qualified. However, the turnover rate for some system engineers appeared to be high. The system engineer for

DC systems was only on the job for about six months. The system engineers for several other systems were only on the job for about six months to 1½ years. However, the team did not identify any specific problems directly linked to the lack of experience on the part of the system engineers.

The team noted that the system engineers interviewed maintained good system notebooks. The system engineers were required to walk down their systems periodically. The team walked down selected plant systems with the system engineers, and considered them knowledgeable on their assigned systems.

The team observed a surveillance test on the Unit 2 125 Volt alternate battery. The test was modified performance test per procedure Dresden Engineering Surveillance (DES) 8300-52. As the DC system engineer at Dresden was relatively new to this test, it was performed under the supervision of a system engineer from Braidwood. The battery testing was done smoothly and no major problems were observed. The team noted good communications with operations and maintenance during these tests.

c. Conclusion

The team concluded that the system engineering department was adequately staffed. The team determined that the engineers interviewed were qualified and experienced in the areas assigned. Good inter-departmental communications were noted between system engineering, operations and maintenance during the special test observed.

E6 Engineering Organization and Administration

a. Inspection Scope (IP 37550; IP 92703)

The team evaluated the performance and effectiveness of the DEAG to determine if the CAL commitments and corrective actions were completed and had satisfied NRC requirements.

b. Observations and Findings

On November 21, 1996, CAL No. RIII-96-016, was issued by the NRC as a result of significant concerns with the station's control of calculations and with the overall performance of site and corporate engineering activities. The CAL identified various planned corrective actions to improve the performance of the engineering organization. One of the planned activities was the formation of an engineering assurance group or DEAG that was composed of senior ComEd engineering personnel and experienced outside experts. The function of the group was to provide oversight of key engineering activities until normal engineering functions had improved to the point where the reviews were no longer necessary.

In NRC Inspection Report 50-237/249-97008(DRS), the NRC evaluated the CAL activities and determined that the CAL commitments and corrective actions were completed, except for those activities associated with the DEAG. The inspection identified that initial DEAG implementation was not effective as an oversight organization. As a result, the CAL remained open until effective DEAG performance was demonstrated.

The team reviewed most of the DEAG review sheets for the period between June 1997 and October 1997, and determined that the DEAG reviews had in most cases, documented relevant significant problems and appropriately required those documents to be corrected. As a result, the DEAG reviews have improved the quality of the engineering products. The DEAG reviews provided good recommendations for improvements in methodology, technical content, and clarification and documentation improvements that would make the engineering products a better source of information for future users.

Since June 1997, the DEAG provided monthly reports to engineering management that summarized the scope of the DEAG activities and the results of the DEAG reviews. The DEAG observations were consistent through November 1997, in identifying areas that needed improvement. The improvement areas were identified as follows:

- Understanding of Regulatory or Design-Basis Requirements on Work Performed
- Attention to Detail
- Interdiscipline Reviews

The team observed that the DEAG reviews were generally thorough and technically sound and produced similar observations with other licensee self-assessment efforts, as described in Section E7. The DEAG efforts showed that the quality of the engineering documentation has improved. However, the team was concerned that many of the DEAG members, who were engineering contractors, were no longer employed at the Dresden site and such loss of experienced personnel might degrade the licensee's ability to maintain an improving trend in engineering performance. Full staffing of qualified personnel in the DEAG was a continuing problem.

c. Conclusions

The team concluded that all commitments and corrective actions identified by Confirmatory Action Letter (CAL) No. RIII-96-016, dated November 21, 1996, including those activities associated with the Dresden Engineering Assurance Group (DEAG) have satisfied NRC requirements. The CAL was closed.

E7 Quality Assurance in Engineering Activities

a. Inspection Scope (IP37550; IP40500)

The team reviewed the following self-assessment documents to assess quality and proposed corrective actions:

- Report Number 237-230-97-00300, "Common Cause Analysis and Investigation of an Adverse Trend in Human Performance Error-Related Licensee Event Report (LER) Rate for the First Two Quarters of 1997 Which Resulted in Exceeding the Dresden 50.54(f) Performance Criterion Action Level, Caused by Failure to Make Timely Change and Inadequate Work Practices," Revision 0

- Report Number 237-251-97-05000, "Plant Engineering Work Management and Support Responsiveness," dated November 18, 1997

- DOC ID# 5549414, "Assessment of Engineering Department Safety Evaluation," Revision 0

b. Observation and Findings

The team's review of the documents identified above indicated that the licensee had taken a pro-active position in an attempt to disclose the performance problems within the organization. Many of the weaknesses identified described similar problems previously identified by the NRC, but the make-up and the openness of the licensee's conclusions indicated a positive trend. For example, the LER common cause analysis investigation identified that the most prevalent problems were associated with personnel acceptance of insufficient time to perform consistent quality technical reviews due to shortcuts taken and inaccurate assumptions made during validation and verification activities. The licensee stated that the same type of errors were occurring station wide and in a variety of processes. In addition, as discussed in Section E6, the DEAG consistently identified that the problems associated with engineering rework were predominately due to inattention to detail as a result of not taking the time to perform an adequate detailed review.

The team observed that the self-assessment documents identified above were focused, provided detailed and relevant observations, and provided a quality product. The self-assessment corrective action recommendations were appropriate for the identified weaknesses. For example, the insufficient time pressure problem was addressed by the LER common cause analysis investigation by the implementation of an Engineering Rapid Response Team (ERRT) to remove short duration emergent work activities from the system engineer's responsibility. In addition, an engineering reporting system (ERS) was developed and implemented to provide a workload scheduling and tracking tool to assist engineering personnel in managing workload.

The team observed that the proposed self-assessment corrective actions have not been fully effective for all proposed recommendations. For example, the ERRT was effective in reducing some of the reactive workload; however, the ERS was too complex and not user friendly to effectively prioritize and manage the engineers workload. The DEAG, as discussed in Section E6, provided quality reviews that contributed to the overall effectiveness of the licensee's self-assessments activities.

c. Conclusions

The team concluded that the licensee's self-assessment activities were pro-active and for the most part effective.

IV. Plant Support Areas

F2 Status of Fire Protection Facilities and Equipment

a. Inspection Scope (IP40500; IP92904)

The team reviewed the licensee's corrective actions concerning problems associated with the control room's HVAC system automatic smoke purge mode.

b. Observations and Findings

During testing of the control room's HVAC system exhaust ducts in November 1994, the licensee discovered that a prior inadvertent change to the control room's HVAC system deleted the automatic smoke purge mode transfer capability as described in UFSAR, Section 6.4.4.3. A URI 50-237/249-96002-07 was generated to track the concern and is discussed further in Section F8.2.

The UFSAR stated that the control room's HVAC system was designed to isolate and maintain design conditions within the control room during fires. In the event of smoke in the control room, the smoke purge mode would allow 100% outside air intake with no recirculation of exhaust air into the control room HVAC zone (envelope). The UFSAR further stated that smoke detectors automatically switched the control room's HVAC system (Train A) to the smoke purge mode.

The licensee concluded that the problem occurred as a result of control room modifications M12-2/3-82-1, M12-0-87-005, and M12-0-86-006. The smoke detectors were inadvertently isolated as a result of modifications to the control room's envelope, which deleted the automatic smoke purge mode transfer capability. As a result, control room operators were required to take manual action to initiate the HVAC smoke purge mode. A safety evaluation to ascertain whether the problem was an unreviewed safety question was not initially performed by the licensee. Following NRC concerns, the licensee performed a safety evaluation prior to startup from the 1996 Unit 2 refuel outage. The licensee concluded that an unreviewed safety question did not exist.

A recent modification, M12-0-96-001, "Control Room HVAC Fire Protection System Modification" corrected the deleted automatic smoke purge mode transfer capability by installing smoke detectors in the remaining ventilation system. However, the team identified that the description of the system's automatic initiation capability had been removed from the UFSAR. Removal of the UFSAR's reference to the control room's automatic transfer to the smoke purge mode was made during the performance of the safety evaluation made in March 1996, just prior to the Unit 2 startup. The UFSAR change was made to accommodate the inadvertent change to the control room HVAC system by only referencing the manual mode. The licensee stated that as a result of two engineers not communicating, one engineer had taken the description for the automatic initiation of the smoke purge mode out of the UFSAR.

The safety evaluation performed in June 1996, for Modification M12-0-96-001, neglected to identify that a change to the UFSAR was required. As a result, during this inspection, the licensee issued PIF# D1997-08239 to correct the affected UFSAR sections concerning the control room HVAC system's automatic initiation.

c. Conclusions

The failure to perform a safety evaluation from November 1994 until March 1996, until identified by the NRC, was a violation of 10 CFR 50.59.
(VIO 50-237/249-97021-02(DRS))

F3 Fire Protection Procedures and Documentation

a. Inspection Scope (IP40500; IP92904)

The team reviewed the licensee's corrective actions concerning problems associated with the Fire Protection Report (FPR).

b. Observations and Findings

The NRC previously identified that polyvinyl chloride (PVC) drain piping was installed during a 1986 control rod drive modification and that the licensee had not performed a safety evaluation nor added the increased combustible fire loading to the FPR's Fire Hazards Analysis (FHA). In addition, the NRC also identified that the construction of a turbine deck concrete building, which was another combustible fire load, had not been added to the FHA. The licensee committed to perform a safety evaluation, investigate/identify other unevaluated plant PVC usage, and specifically evaluate PVC usage during the modification process and to include the identified combustible fire loads in the next update to the FHA. A URI 50-237/249-96002-09(DRS) was generated to track the concern and is discussed further in Section F8.3.

Branch Technical Position Auxiliary Power Conversion System Branch (BTP APCSB) 9.5.1, "Guidelines for Fire Protection for Nuclear Power Plants," dated May 1976, was an FPR requirement, which required the minimization of PVC usage in the plant. The team determined that the safety evaluation completed as part of the licensee's corrective action was acceptable. During the licensee's investigation, additional in-plant PVC usage was identified. In addition, the licensee had changed the modification process to ensure that PVC usage was minimized in the plant.

The team observed, however, that the combustible fire load items were never added to the FHA, which included the PVC usage and turbine deck concrete building previously identified. The reason that the combustible fire load items had not been incorporated into the FHA was that the FPR had not been updated since 1994. The FHA is part of the FPR and the FPR was considered part of the UFSAR.

Generic Letter (GL) 86-10, "Implementation of Fire Protection Requirements," dated April 24, 1986, stated that fire protection plans and programs shall be incorporated as part of the UFSAR and therefore, would be updated and submitted to the NRC in accordance with the requirements of 10 CFR 50.71(e). GL 86-10 also stated, "All changes to the approved program shall be reported annually to the Director of the Office of Nuclear Reactor Regulation, along with the UFSAR revisions required by 10 CFR 50.71(e)." The failure to submit revised portions of the FPR to the NRC was a violation of 10 CFR 50.71(e). (VIO 50-237/249-97021-03(DRS))

The team also observed a weakness within the licensee's corrective action process concerning these earlier identified FPR problems. Following NRC Inspection Report 96002 (February 14, 1996, through March 29, 1996), Quality and Safety Assessment (Q&SA) wrote Corrective Action Record (CAR) 12-96-151 "Fixed Combustible Loading." The CAR identified that, contrary to the requirements of GL 86-10 and Engineering Procedure ENC-QE-85, "Control and Revision of the Fire Protection Program Documentation," updates to the FHA Report, which was part of the FPR, had not been submitted to the NRC. A PIF and NTS item were generated on December 12, 1996, 10 months after the identification of the earlier FPR problems. NTS history indicated that completion of the FPR update was extended from June 30, 1997, to September 1, 1997, and then to December 18, 1998. In addition, on November 7, 1997, Q&SA identified that there was no process to receive, evaluate, track, and update FPR information.

On November 19, 1997, the licensee opened NTS Item #237-225-97R12-97242 to track the development of a procedure to control updating of the FPR and provide interim tracking of FHA changes. A due date of September 4, 1998, was assigned to the NTS item. Currently, the FPR does not represent plant conditions. The identification and corrective actions for FPR problems were not timely.

The team further identified that fire risks associated with the additional combustible fire loading had not been incorporated into the fire pre-plans. Technical Specification (TS) 6.2.A stated that written procedures shall be established and implemented covering these activities. Dresden Fire Protection Procedure (DFPP) 4100-01, Revision 1, "Fire Protection Program," required that Fire Pre-Plans be updated annually. The Dresden "Fire Pre-Plans," Revision 2, had not been updated since September 1992. The licensee's failure to comply with these requirements was a violation of TS 6.2.A. (VIO 50-237/249-97021-04(DRS))

c. Conclusions

Failure to update and submit the revised portions of the FPR to the NRC was a violation of 10 CFR 50.71(e). (VIO 50-237/249-97021-03(DRS)) Failure to update the fire pre-plans was a violation of TS 6.2.A. (VIO 50-237/249/97021-04(DRS))

F8 Miscellaneous Fire Protection Issues (IP92904)

F8.1 (Closed) VIO 50-237/249-96002-05B(DRS): This violation was issued for not performing a full 8 hour discharge test on 47 Appendix R emergency lighting units as required by DES 4153-04, "Emergency Lighting Discharge Test," Revision 0. The licensee changed the procedure/surveillance to ensure that the batteries were discharge tested for the full 8 hours. The team reviewed two years of surveillance data and determined that the licensee's corrective actions were effective. This item was closed.

F8.2 (Closed) URI 50-237/249-96002-07(DRP): This unresolved item was issued for inadvertently deleting the control room HVAC system automatic smoke purge mode transfer capability as described in UFSAR, Section 6.4.4.3. The change to the automatic smoke purge mode had been made as a result of a control room modification. A recent modification corrected the control room's HVAC system automatic smoke purge mode problem. However, a violation was issued for not performing a safety evaluation as discussed in Section F2. This item was closed.

F8.3 (Closed) URI 50-237/249-96002-09(DRS): This unresolved item was issued for using PVC during a modification without performing a safety evaluation. The licensee completed the safety evaluation and concluded there was no unreviewed safety question. During the team's review, the FPR was observed as not having been updated for PVC usage and the addition of a turbine deck concrete building. As a result, a violation was issued for not having updated the FPR since 1994 as discussed in Section F3. This item was closed.

V. Management Meetings

X1 Exit Meeting Summary

The team presented the final inspection results to members of licensee management at the conclusion of the inspection on January 27, 1998. The team initially met with the licensee's representatives to summarize the scope and findings of the on-site inspection activities on November 26, 1997. During both of these meetings, the team questioned licensee personnel as to the potential for proprietary information being included or retained in the inspection report material as discussed at the exits. No proprietary information was identified as included or retained.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

G. Abrell, NRC Coordinator, Regulatory Assurance
D. Ambler, Regulatory Assurance Supervisor (Acting), Regulatory Assurance
H. Anagnostopoulos, Corrective Action Process (CAP) Supervisor, Quality & Safety Assessment
R. Book, CAP Staff, Quality & Safety Assessment
A. Casillo, Mechanical Lead (M1), Design Engineering
W. Clover, Design Engineer, Design Engineering
J. Dawn, DEAG Supervisor, Plant/Engineering Programs
F. Fink, Business Manager, Dresden
M. Friedmann, HP Technical Lead, Health Physics
R. Freeman, Site Engineering Manager, Dresden
W.Halcott, Auxiliary System Lead, Systems Engineering
M.Heffley, Site Vice President, Dresden
K. Housh, ISEG Engineer, Quality & Safety Assessment
L. Jordan, Training Manager (Acting), Training
A. Khanna, Design Lead, Design Engineering
J. Kish, CCSW System Engineer, Systems Engineering
W. Lipscomb, Assessor, Site Vice President Staff
R. Mahendranathan, Mechanical Engineer, Design Engineering
T. McGowan, DC System Engineer, Electrical System & Components
E. Netzel, Director, Supplier Evaluation Services/Nuclear Oversight
K. Peterman, Supervisor, Configuration & Administration Management; DEAG Member
P. Planing, Superintendent, Systems Engineering
P. Racicot, AC System Engineer, Electrical System & Components
C. Richards, Audit Supervisor, Quality & Safety Assessment
E. Salinas, System Engineer, Systems Engineering
B. Shete, Mechanical Engineer, Design Engineering
F. Spangenberg, Regulatory Assurance Manager, Dresden
D. Spencer, Electrical System & Components Lead, Systems Engineering
S. Tutich, Electrical Lead, Design Engineering
L. Weir, Superintendent, Design Engineering
D. Winchester, Manager, Quality & Safety Assessment

ComEd Contractors

H. Campbell, Member, DEAG (Titan)
C. Kinstler, Engineer (Sargent & Lundy)
H. McCullough, Site Lead (Acting), Design Basis Initiative (Sargent & Lundy)

LIST OF INSPECTION PROCEDURES USED

IP 37550:	Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 92703:	Followup of Confirmatory Action Letters
IP 92904:	Followup - Plant Support

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-237/249-97021-01(DRS)	URI	UFSAR Dam Failure Discrepancies
50-237/249-97021-02(DRS)	VIO	Failure to Perform 50.59 Evaluation
50-237/249-97021-03(DRS)	VIO	Failure to Update FPR and Submit to NRC
50-237/249-97021-04(DRS)	VIO	Failure to Update Fire Pre-plans

Closed

50-237/249-96002-05B(DRS)	VIO	Failure to Adequately Test Emergency Lighting
50-237/249/96002-07(DRP)	URI	Untimely Resolution of Operability Evaluations
50-237/249-96002-09(DRS)	URI	Polyvinyl Chloride (PCV) Usage Not Well Controlled

LIST OF ACRONYMS

ATTN	Attention
BWR	Boiling Water Reactor
CAL	Confirmatory Action Letter
CAR	Corrective Action Record
CCSW	Containment Cooling Service Water
CFR	Code of Federal Regulations
ComEd	Commonwealth Edison
DAP	Dresden Administrative Procedure
DEAG	Dresden Engineering Assurance Group
DES	Dresden Engineering Surveillance
DFPP	Dresden Fire Protection Procedure
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
DTI	Desk Top Instruction
E&TS	Engineering and Technical Support
GL	Generic Letter
HVAC	Heating, Ventilation, and Air Conditioning
ISEG	Independent Safety Engineering Group
JSPLTR	ComEd (J.S. Perry) Letter
LOCA	Loss of Coolant Accident
LPCI	Low Pressure Coolant Injection
LPM	Licensing Project Manager
MSL	Mean Sea Level
NEP	Nuclear Engineering Procedure
NOC-BOD	Nuclear Operating Committee-Board of Directors
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NTS	Nuclear Tracking System
PDR	Public Document Room
PIF	Problem Identification Form
PVC	Polyvinyl Chloride
Q&SA	Quality and Safety Assessment
RBCCW	Reactor Building Closed Cooling Water
RG	Regulatory Guide
SRI	Senior Resident Inspector
SW	Service Water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
USQ	Unreviewed Safety Question
VIO	Violation

PARTIAL LIST OF DOCUMENTS REVIEWED

DOCUMENT NUMBER	DOCUMENT DESCRIPTION	REVISION OR DATE ISSUED
CAL No. RIII-96-016	Confirmatory Action Letter	November 21, 1996
CAR 12-96-151	Fixed Combustible Loading	December 23, 1996
CAR 12-97-105	Fire Protection Report	November 7, 1997
DAP 02-27	The Integrated Reporting Process (IRP)	Revision 7
DAP 21-03	Processing Plant Design Changes	Revision 13
DEAG Review Sht 8.10	Removal of Description of Acid & Caustic Equipment from UFSAR	August 21, 1997
DEAG Review Sht 8.11	Troubleshooting of a Stator Leak	August 22, 1997
DEAG Review Sht 8.16	Clarification of Information on an Overhead Crane	August 22, 1997
DEAG Review Sht 8.17	Clarification of Spent Fuel Pool Liner Thickness	August 22, 1997
DEAG Review Sht 8.28	Security Position Title Change in the UFSAR	August 28, 1997
DES 4153-04	Emergency Lighting Discharge Test	Revision 0
DFPP 4100-01	Fire Protection Program	Revision 1
-------	Dresden Engineering Assurance Group Activities for May, 1997 (1st DEAG Monthly Report)	June 26, 1997
DOC ID # 0005458065	Dresden Engineering Assurance Group Activities for June, 1997	July 11, 1997
DOC ID # 0005491140	Dresden Engineering Assurance Group Activities for July, 1997	August 18, 1997
DOC ID # 0005503264	Dresden Engineering Assurance Group Activities for August, 1997	September 8, 1997
DOC ID # 0005558157	Dresden Engineering Assurance Group Activities for October, 1997	November 17, 1997

DRE 97-0171	Calculation for Determination of Acceptance Criteria for CCSW One and Two Pump NPSH Testing - Units 2 & 3	Revision 0
DRE 97-0172	Calculation to Determine Submergence for Excessive CCSW Intake Vortexing Prevention.	Revision 0
DTI-DE-15	Roles and Responsibilities of the Dresden Engineering Assurance Group	Revisions 0, 1, 2
ENC-QE-85	Control and Revision of the Fire Protection Program Documentation	
Eval Doc ID #5543459	CAL Action Item Update Report Following First Monthly Status Meeting Held December 19, 1996	December 30, 1996
GL 86-10	Implementation of Fire Protection Requirements	April 24, 1986
JSPLTR: 97-0005	ComEd Interim Response to NRC Independent Safety Inspection Report	January 13, 1997
JSPLTR: 97-0041	ComEd Response to NRC Independent Safety Inspection Report	February 26, 1997
JSPLTR: 97-0043	Verification Screening of Key Parameters for Twelve Risk Significant Systems	Revision 0
M12-0-96-001	Control Room HVAC Fire Protection System Modification	
NEP-04-01DR	Dresden Plant Modification Site Appendix	Revision 2
NEP 10-03	Disposition of Design Basis Discrepancies	Revision 0
NEP 12-01	Preparation, Review, and Approval of Design Input Requirements	Revision 2
NEP 12-02	Preparation, Review, and Approval of Calculations	Revision 4
NSWP-A-15	ComEd Nuclear Division Integrated Reporting Program	Revision 0 & 1
OP EVAL 97-81	Minimum Water Level in CCSW Intake Bay	July 8, 1997
PIF # D1997-05554	UFSAR CCSW Piping Statement Discrepancy	June 25, 1997

PIF # D1997-05556	UFSAR Safety Grade Cold Shutdown Capability Discrepancy	June 25, 1997
PIF # D1997-05955	UFSAR LPCI Flow Timing Discrepancy	June 24, 1997
PIF # D1997-06487	Incorrect Source Document Referenced for Diesel Generator Cooling Water Pump in a Calculation	August 27, 1997
PIF # D1997-08239	UFSAR Deletion/Addition	November 21, 1997
PIF # D1997-08290	NRC Concerns About CCSW System Performance After a Dam Failure Coincident With a LOCA	November 25, 1997
PIF # 227A-12-1997-012788	UFSAR Implied One CCSW Pump Operation After a Dam Failure Coincident With a LOCA	February 25, 1997
Report Base NTS Number: 237-251-97-05000	Plant/Programs Engineering Sel Assessment 3-7 Nov 97	November 18, 1997
-------	Fire Protection Report (FPR)	Amendment 10 December 1994

Commonwealth Edison Company
Dresden Generating Station
6500 North Dresden Road
Morris, IL 60450
Tel 815-942-2920

ComEd

April 6, 1998

JMHLTR: #98-0083

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555

Subject: Dresden Nuclear Power Station Units 2 and 3
Reply to a Notice of Violation; Inspection Report 50-237/249/97021
<u>NRC Docket Numbers 50-237 and 50-249</u>

Reference: (a) J.A. Grobe letter to O.W. Kingsley, dated March 6, 1998, transmitting NRC Inspection Report 50-237/249/97021 and Notice of Violation

(b) J.M. Heffley (ComEd) to USNRC letter dated March 13, 1998, Design Basis Initiative Program

(c) J.M. Heffley (ComEd) to USNRC letter dated March 31, 1998, Design Basis Initiative Program

The purpose of this letter is to provide ComEd's reply to the three violations denoted in the Notice of Violation transmitted by reference (a). The first violation was for failure to perform a written safety evaluation following the inadvertent change to the control room ventilation system which deleted the automatic smoke purge capability. The second violation was for failure to update the Fire Protection Report as required by 10 CFR 50.71(e). The third violation was for failure to review and revise the Fire Preplans in accordance with the Dresden Fire Protection Program. The responses to each of these items are found in the attachments.

Included in reference (a) was an Unresolved Item URI 50-237/249-97021-01 (DRS). The team had concerns that the Updated Final Safety Analysis Report (UFSAR) did not accurately characterize the plant's design-basis or the plant's capability to respond to a potential Dresden Lock and Dam failure. During the meeting with NRC representatives at Region III headquarters on March 4, 1998, ComEd identified several discrepancies in Section 9.2.5.3.2 "Dam Failure Coincident with a Loss of Coolant Accident (LOCA)" of Dresden's Updated Final Safety Analysis Report.

Reference (b) identified these discrepancies and concluded that a review of Dresden's design criteria reveals that postulating a dam failure coincident with a LOCA was not part of its original design basis. It also stated that Dresden was preparing a Proposed License Amendment to clarify the licensing basis with respect to dam failure.

Dresden has subsequently concluded that a License Amendment is not necessary and that clarifications to the UFSAR may be made through the provisions of 10 CFR 50.59. Reference (c) provided the basis for this conclusion.

This response contains no proprietary or safeguards information. If there are any questions concerning this letter, please refer them to Mr. Frank Spangenberg, Dresden Station Regulatory Assurance Manager, at (815) 942-2920 extension 3800.

Sincerely,

J. M. Heffley
Site Vice President
Dresden Station

Attachment

cc: A. Bill Beach, Regional Administrator, Region III
M. Ring, Branch Chief, Division of Reactor Projects, Region III
L. Rossbach, Project Manager, NRR (Unit 2/3)
K. Riemer, Senior Resident Inspector, Dresden
Office of Nuclear Facility Safety - IDNS

ATTACHMENT
RESPONSE TO NOTICE OF VIOLATION
NRC INSPECTION REPORT
50-237/97021, 50-249/97021
9702102

VIOLATION:

10CFR 50.59 permits the licensee, in part, to make changes to the facility, and procedures, as described in the safety analysis report, without prior Commission approval, provided the changes do not involve an unreviewed safety question (USQ). Records of these changes must include a written safety evaluation which provides the bases for the determination that the changes do not involve an USQ.

Prior to March 22, 1996, the Dresden Updated Final Safety Analysis Report, Sections 6.4.2 and 6.4.4.3, in part, stated that for fire and smoke protection, the control room heating, ventilation, and air conditioning (HVAC) system was designed to isolate and maintain the design conditions within the control room during fires. The control room Train A HVAC system was capable of both automatic and manual transfer from the normal operating mode to the smoke purge mode. Automatic transfer to the smoke purge mode was initiated by smoke detectors, located in the control room return air ducts.

Contrary to the above, in November 1994, the licensee identified that a prior inadvertent change to the Dresden Station's control room ventilation system design deleted the automatic smoke purge mode transfer capability. From November 1994 to March 1996, the licensee failed to perform a written safety evaluation to provide the bases for the determination that the change did not involve an USQ.
(VIO 50-237/249-97021-02(DRS))

This is a Severity Level IV violation (Supplement 1).

REASON FOR VIOLATION:

Personnel conducting the surveillance testing of Control Room Ventilation System Smoke Detectors did not perform an operability evaluation of the system when the automatic feature of the smoke purge mode failed in November 1994. Had this been done, a safety evaluation of the system without automatic smoke purge would have been conducted. The personnel performing the test believed there to be a problem with the field installation and continued their efforts to find the problem. In March of 1996, they determined that there was an error in the design which prevented operation of the automatic purge mode and performed the safety evaluation at that time. Additional details are provided below:

Upon completion of surveillance testing of smoke detectors, Special Procedure (SP) 94-100, on November 14, 1994, some unexpected test results were encountered. Work

Request (WR) 940099080 and Problem Identification Form (PIF) 237-201-94-MM72300 were generated to document that ventilation dampers 2/3-9472-023 and 24 would not operate and to repair them. Engineering determined that the field installation of the detectors did not meet design wiring diagrams. Engineering Requests (ERs) 9501913 and 9502320 were initiated to resolve the installed configuration with the design. On May 20, 1995, the Control room habitability concerns were addressed by Engineering and the manual purge mode was allowed for emergency use to clear smoke and fumes from the Control Room. This was a temporary fix until the ERs were addressed. The result of the ERs was a modification package to resolve identified deficiencies with smoke detectors in March 1996. During the modification process a 10 CFR 50.59 Safety Evaluation was performed covering the modification of the smoke detector installations. Surveillance activities were delayed when smoke detector design and installation deficiencies were identified. The installation was determined to be in accordance with the design, but the design did not function in the automatic smoke purge mode. Once this was identified, a modification package was generated to correct the deficiencies

From November 1994 to March 1996, the personnel working with the Smoke Purge Mode Installation did not question the design and did not perform a 10 CFR 50.59 safety evaluation for an USQ. A safety evaluation was performed on Smoke Purge Mode design function prior to installation.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED:

When the design deficiencies were identified in March 1996, a 10 CFR 50.59 safety evaluation was performed by Design Engineering. This safety evaluation determined that the removal of the automatic smoke purge capability of the control room HVAC was not an USQ. Branch Technical Position APCSB 9.5.1, "Fire Protection Requirements," requires only manual purge operation, which was maintained. However, Dresden ~~will~~ re-installed the automatic purge function in accordance with current industry practices.

In a parallel effort, a UFSAR change to remove the automatic smoke purge function was initiated and a modification package was initiated to resolve the deficiencies. The UFSAR change was completed while the field installation for the modification package was being implemented in the field.

The field installation of the modification was delayed from January 1997 through August 1997 because dampers 2/3-9472-023 and 024 were damaged. The dampers were installed in August 1997 and the smoke detector surveillance was satisfactorily completed. The automatic smoke purge mode was found acceptable on August 21, 1997.

NTS item # 2372609754301A, planned for completion by July 1, 1998, was initiated to change the UFSAR to reflect that the Control Room HVAC System has both automatic and manual initiation of the smoke purge mode.

CORRECTIVE STEPS TAKEN TO AVOID FURTHER VIOLATION:

Active involvement of the System Manager and Engineering is required to ensure the plant design basis is maintained and equipment operates in accordance with designed functions. To ensure these elements:

1. Engineering Support Personnel Training has been implemented to develop a questioning attitude among Engineering personnel. If equipment does not respond or operate in accordance with the design, actions should be implemented to document, troubleshoot, and resolve the problems. Documentation that should be generated are PIFs, ERs, and as applicable, safety evaluations, and operability determinations as defined in Corporate and Dresden procedures.

2. The Plant Engineering Handbook has been developed to define responsibilities of the System Manager including definition and resolution of design and operability concerns In part, the handbook requires that Plant Engineering be aware of design basis and applicable license requirements and helps ensure that maintenance, operations, and testing activities are conducted in accordance with these requirements.

The above actions have been implemented to prevent reoccurrence through personnel training, engineering guidance, and procedures to control activities more rigorously. The current administrative programs and procedures have been continuously assessed and revised over the time span covered by these deficiencies and have matured to be more comprehensive.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED:

Full compliance will be obtained when the UFSAR is changed to incorporate the automatic smoke purge function in the UFSAR is completed on July 1, 1998.

ATTACHMENT
RESPONSE TO NOTICE OF VIOLATION
NRC INSPECTION REPORT
50-237/97021, 50-249/97021
97021-03

VIOLATION:

10 CFR 50.71(e) states, in part, that the licensee shall submit revisions containing information to the Final Safety Analysis Report (UFSAR) to the NRC annually or six months after each refueling outage provided the interval between successive updates does not exceed 24 months.

Contrary to the above, from November 1994 through November 21, 1997, the Fire Protection Report, referenced as part of the UFSAR, had not been updated and the revision updates submitted to the NRC.

This is a Security Level IV violation (Supplement 1).

REASON FOR VIOLATION:

Prior to December 1997 Dresden did not clearly understand that the Fire Protection Report (FPR) was part of the UFSAR and subject to the requirements in 10 CFR 50.71(e) for updating the UFSAR. In December 1997, ComEd Corporate personnel reviewed Dresden's License Amendments 106 and 101 for Dresden Units 2 and 3, respectively, and the NRC's Safety Evaluation Report for those amendments. It was concluded that the Dresden Fire Protection Report is part of the UFSAR with regard to the periodic report of changes required by 10 CFR 50.71(e).

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED:

Dresden has identified and understands the requirements for updating the FPR and reporting those changes to the NRC. In accordance with NRC Generic Letter 86-10, all changes to the approved Fire Protection Program shall be reported along with the UFSAR revisions required by 10 CFR 50.71(e). The current revision policy for the Dresden UFSAR is to submit the revision to the UFSAR to the NRC no later than 24 months from the date of the previous revision submittal.

Dresden is working on the 1996 FPR update, which is scheduled for completion and submittal to the NRC by August 30, 1998. This activity is being tracked by NTS Item No. 237-315-96-15101.

CORRECTIVE STEPS TAKEN TO AVOID FURTHER VIOLATION:

ComEd will develop a procedure to control the updating of the Fire Protection Report. This procedure will reflect the updating and reporting requirements identified above. This work is being tracked by NTS Item No. 237-225-97-R12-97242.

The 1998 FPR Update is presently scheduled for completion to coincide with Dresden's present 24 month schedule for submitting UFSAR updates to the NRC. This work is being tracked by NTS Item No. 237-100-97-210302.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED:

Full compliance will be achieved with the UFSAR submittal in the second quarter of 1999.

RESPONSE TO NOTICE OF VIOLATION
NRC INSPECTION REPORT
50-237/97021, 50-249/97021
97021-04

VIOLATION:

Technical Specification 6.2.A states, in part, that written procedures shall be established and implemented covering the activities referenced in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, dated February 1978. The activities listed in RG 1.33 included procedure review and the approval process.

Dresden Fire Protection Program Procedure (DFPP) 4100-01, "Fire Protection Program," Revision 1, Section G.2.a.(7) required that fire pre-plans be reviewed on an annual basis, and revised as appropriate.

Contrary to the above, as of November 21, 1997, the fire pre-plans had not been reviewed or revised since September 1992. (VIO 50-237/249-97021-04(DRS))

This is a Security Level IV violation (Supplement 1).

REASON FOR VIOLATION:

Previous reviews of the Dresden fire pre-plans were not adequately documented. When Dresden formed the Safety and Property Loss Prevention Group, the review of the fire pre-plans was not added as an annual surveillance (predefine). Consequently there was no mechanism to assure the review would be completed and documented.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED:

When it was determined that the fire pre-plans had not been updated, a Problem Identification Form (PIF) was generated. An apparent cause evaluation was performed identifying the need for a predefine to track the review of the fire pre-plans and the documentation to show the review was completed.

CORRECTIVE STEPS TAKEN TO AVOID FURTHER VIOLATION:

An Action Request was initiated to create the predefine for future reviews and revisions to the fire pre-plans (completed)

Current fire pre-plans are in the process of being updated. This update will be completed by May 15, 1998. (NTS #237-315-98-00501A)

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED:

Full compliance will be achieved with the completion of the fire pre-plan review and documented results on May 15, 1998.

TAB 22

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
801 WARRENVILLE ROAD
LISLE, ILLINOIS 60532-4351

December 18, 1998

Mr. Oliver D. Kingsley
President Nuclear Generation Group
Commonwealth Edison Company
ATTN: Regulatory Services
Executive Towers West III
1400 Opus Place, Suite 500
Downers Grove, IL 60515

SUBJECT: NRC INSPECTION REPORT 50-237/98029(DRS); 50-249/98029(DRS)

Dear Mr. Kingsley:

On December 3, 1998, the NRC completed an inspection of your fire protection program at the Dresden Nuclear Power Station, Units 2 and 3. The enclosed report presents the results of the inspection.

Areas examined within your fire protection program are identified in the report. Within those areas, the inspection consisted of a selective examination of procedures and representative records, interviews with personnel, and observation of activities in progress. The objective of the inspection effort was to determine whether activities authorized by the license were conducted safely and in accordance with NRC requirements. Based on the results of this inspection, no violations of NRC requirements were identified.

Our inspection concluded that your fire protection program was good. Fire protection equipment was well maintained and transient combustibles were well controlled.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and the enclosed report will be placed in the NRC Public Document Room.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

Ronald N. Gardner

Ronald N. Gardner, Chief
Engineering Specialist Branch 2
Division of Reactor Safety

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

Enclosure: Inspection Report 50-237/98029(DRS); 50-249/98029(DRS)

See Attached Distribution

cc w/encl: D. Helwig, Senior Vice President
H. Stanley, PWR Vice President
C. Crane, BWR Vice President
R. Krich, Regulatory Services Manager
D. Greene, Licensing Director
DCD - Licensing
M. Heffley, Site Vice President
P. Swafford, Station Manager
F. Spangenberg, Regulatory Assurance Manager
R. Hubbard
M. Aguilar, Assistant Attorney General
State Liaison Officer
Chairman, Illinois Commerce Commission

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos.:	50-237; 50-249
License Nos.:	DPR-19; DPR-25
Report No.:	50-237/98029(DRS); 50-249/98029(DRS)
Licensee:	Commonwealth Edison Company
Facility:	Dresden Generating Station Units 2 and 3
Location:	6500 North Dresden Road Morris, IL 60450
Dates:	December 1 to 3, 1998
Inspector:	D. Chyu, Reactor Engineer
Approved by:	Ronald Gardner, Chief, Engineering Specialists Branch 2 Division of Reactor Safety

EXECUTIVE SUMMARY

Dresden Nuclear Power Plant, Units 2 and 3
NRC Inspection Report 50-237/98029(DRS); 50-249/98029(DRS)

This inspection reviewed the fire protection program, an aspect of Plant Support. This was an announced inspection conducted by one regional inspector. The following strengths and weaknesses were identified:

- Housekeeping was good and combustible material was well controlled. Required fire protection features appeared to be well maintained. One unresolved item was identified regarding fire stops and fire retardant coatings on redundant cable trays which were no longer maintained by the licensee in risk sensitive areas (Section F2).

- The inspector concluded that the fire protection procedures reviewed provided adequate fire protection controls and were adequately implemented by station personnel (Section F3).

- The performance of the observed fire drill was good. A weakness was identified where the offsite fire department had not participated in fire drills with onsite fire brigade members since 1994 (Section F6).

- Fire protection quality assurance audit reports and checklists were thorough and contained substantive findings (Section F7).

Report Details

IV. Plant Support

F2 Status of Fire Protection Facilities and Equipment

a. Inspection Scope

The inspector toured selected areas of the turbine and reactor buildings, and 2/3 crib house to observe the adequacy and control of combustibles, dampers, fire doors, hose stations, detection equipment, extinguishers, sprinkler systems, emergency lights, fire pumps, fire carts, and housekeeping. The inspector also reviewed the fire protection features as described in applicable safety evaluation reports (SERs) and verified the installation of these fire protection features in several risk sensitive areas.

b. Observation and Findings

Minimal amounts of combustible material were noted in the plant. The general housekeeping was good. Fire protection features reviewed appeared to be well maintained and functional as verified by completed surveillance procedures. Based on the licensee's IPEEE submittal report dated December 1997, the core damage frequency (CDF) resulting from fire scenarios was 2.5E-04 per reactor-year for Unit 2 and 2.8E-04 for Unit 3. The inspector toured the following risk-sensitive areas:

- Unit 2 turbine building mezzanine, Fire Zone 8.2.6.A (30% of Unit 2 fire CDF)
- Unit 2/3 turbine building mezzanine central, Fire Zone 8.2.6.C (29% of Unit 2 CDF and 23% of Unit 3 CDF)
- Unit 3 track way and switchgear area, Fire Zone 8.2.5.E (21% of Unit 3 fire CDF)
- Unit 3 reactor building 545' elevation, Fire Zone 1.1.1.3 (20% of Unit 3 fire CDF)
- Unit 2 reactor building 545' elevation, Fire Zone 1.1.2.3 (12% of Unit 2 CDF)

In the turbine building ground and mezzanine areas, the inspector verified that fire suppression systems were installed around the track ways, turbine oil reservoirs, hydrogen seal oil units, electro-hydraulic control oil reservoirs, and Unit 2 instrument air compressors. The suppression systems were adequately positioned to cover potential fire hazards. Manual CO_2 and hose stations were installed throughout these fire areas. The manual actuation stations for the hydrogen seal oil deluge systems were located away from the areas of concern. A booster hose station was also installed in the area of Switchgears 23 and 24 for fighting an electrical fire. The inspector verified that fire detection systems were installed above Switchgears 21, 22, 23, 25, 26, 31, 32, 33, 34, 35, and 36. The inspector also reviewed Dresden Fire Protection Surveillance (DFPS) 4175-05, "Safety-Related Electrical Cabinets Visual Inspection," Revision 2, to ensure that the top of Switchgears 23 and 24, and motor control centers (MCCs) 28-3, 29-2, and 29-3 were properly sealed against the entry of water during manual fire suppression activities.

In the Units 2 and 3 reactor building (545' elevations), the inspector verified that the fire detection system was installed above and below the metal water shields covering Switchgears 23-1, 24-1, 33-1, and 34-1. The inspector also verified that the barrier walls between Switchgears 23-1 and 24-1 and between Switchgears 33-1 and 34-1, were extended to the underside of the metal water shield as described in applicable SERs.

As stated in the Office of Nuclear Reactor Regulation Safety Evaluation Report dated March 22, 1978, the licensee committed to make certain plant modifications to improve the Dresden fire protection program. The licensee committed to install fire stops in cable trays which provided a continuity of combustible material between two different divisions of safety related cables. Furthermore, fire retardant coatings were to be applied to cables on each side of the fire stops for a distance of 3 feet in horizontal trays and 5 feet in vertical trays wherever stacked or open cable trays existed (Sections 3.1.14 and 4.10 in March 1978 SER). In addition, the licensee also committed to apply a fire retardant coating to cables in the auxiliary electrical equipment room and at 4KV and 480V switchgear and MCCs where the separation of redundant cables was less than 5 feet vertically and 3 feet horizontally (Sections 3.1.20, 5.4, and 5.9.4 in March 1978 SER).

During the plant tours, the inspector identified that these fire protection features were no longer maintained by the licensee in the Units 2 and 3 track way areas (Fire Zones 8.2.5.A and 8.2.5.E). In the area of Switchgears 35 and 36 and Buses 31 and 32, the inspector noted that cables (combustibles) were routed between two divisions of safety related cable trays. However, there were no fire stops in these cable trays to prevent a fire in one division from propagating to the other division.

In the Unit 2 track way area, the inspector noted two trays of redundant cables were joined to a T-shape cable tray. However, there were no fire stops installed at the junctions. In the vicinity of MCC 26-8, the inspector observed that no fire retardant coatings were applied to cables where the distance between Divisions I and Division II cable trays (stacked) was less than 5 feet vertically. The above examples were not all-inclusive of the cable trays in the Units 2 and 3 track way areas.

The licensee's evaluation, "Guidelines of Appendix A to APCSB 9.5-1," Revision 2, dated February 1986, stated that for a fire involving redundant cable trains in a fire area, an alternate shutdown path would be available outside the affected area. The licensee further stated that the fire stops identified in the 1978 SER Section 3.1.14 no longer needed to be maintained except for those located on the first floor of the Units 2 and 3 reactor building. This change in commitment was not previously reviewed and approved by the NRC.

The licensee's facility operating license No. DPR-19 and 25, Section 2.E required that the licensee shall implement and maintain all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report for the facility and as approved in the Safety Evaluation Report dated March 22, 1978 and other supplements. As stated in Generic Letter 86-10 and the license condition, the licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown conditions in the event of a fire.

Units 2 and 3 track ways contain redundant trains of cables and require alternate shutdown methodology to achieve and maintain safe shutdown conditions during a postulated fire. The alternate shutdown method relies on the isolation condenser, 2/3 diesel generator, and control rod drive pump. The fire protection features for these areas are required to limit fire damage to safety related cables such that the unit can be shut down with minimal fire damage and without instituting the alternate shutdown methodology. The licensee committed to provide additional documentation to demonstrate the basis for not maintaining fire stops and fire retardant coatings as discussed above. This is considered an unresolved item pending NRC review of additional licensee documentation (URI 50-237/249-98029-01).

c. Conclusion

Plant housekeeping was good and minimal combustible material was noted. Required fire protection features appeared to be well maintained. Concerns were identified regarding fire stops and fire retardant coatings of redundant cable trays which were no longer maintained by the licensee in risk-sensitive areas.

F3 Fire Protection Procedures and Documentation

a. Inspection Scope (64704)

The inspectors reviewed the following fire protection procedures:

- DAP 07-48, "Control of Lay Down, Storage Area, and Equipment in Use," Revision 6
- DHP 0230-02, "Fire Protection for Transient Combustibles," Revision 2
- DFPP 4100-03, "Fire Watch Procedure," Revision 02
- DFPP 4123-11, "Emergency Response Drills," Revision 06

b. Observations and Findings

During the plant tours, the inspector noted an area adjacent to Switchgears 35 and 36 which the licensee set up as an asbestos removal change-out area. Since combustible material was introduced in that area, the licensee had initiated a transient combustible permit for the area. Based on a review of this area, the inspector concluded that the licensee was controlling transient combustibles in accordance with procedure DHP 0230-02.

During the tours in the turbine building mezzanine central zone (Fire Zone 8.2.6.C) and Unit 2 track way, the inspector noted the storage of resins and protective clothing. The inspector verified that the fire hazard analysis included resins and protective clothing as part of the fixed combustible material fire loading analysis. This was considered acceptable.

The inspectors noted that the licensee's definition for continuous fire watch stated, "that each location, within the specified area, be observed at least once every 15 minutes with a margin of five minutes." The inspector was concerned that this definition did not meet the underlying purpose of a continuous fire watch requirement. The licensee indicated that in a letter transmitted to all ComEd stations, limitations were imposed for implementing the requirement of continuous fire watch. The limitations were as follows:

- An area to be patrolled has easy access which meant no locked doors, step-off pads, or hazards that would impede the observation of each location within the specified area.

- A specified area may consist of more than one fire zone provided easy access can be demonstrated.
- At no time should more than one fire area or elevation be specified for observation.

The licensee added the limitations to the fire watch procedure. In addition, the Dresden Administrative Technical Requirement (DATR) contained adequate controls and limits for inoperable fire protection equipment. For each inoperable water suppression system or for a specified number of inoperable detectors, the DATR specified required compensatory actions such as continuous or hourly fire watch. In addition, the licensee implemented an administrative limiting condition for operation (LCO) which required the restoration of inoperable fire protection equipment within 14 days or the initiation of a problem identification form (PIF) to track corrective actions.

In 1998, there were about 340 entries into DATR LCOs for inoperable water suppression and fire detection equipment. None of the repairs exceeded the 14-day LCO restoration requirement; therefore, no PIFs were initiated. In 1997, there were 5 PIFs initiated for exceeding the 14-day LCO due to planned outage work on the underground piping systems. In 1996, there were no PIFs associated with exceeding the 14-day DATR LCO. The inspector concluded that the licensee took prompt corrective actions for inoperable water suppression and fire detection equipment and did not rely on compensatory actions such as continuous or hourly fire watches in lieu of operable equipment. The inspector considered the incorporation of additional limitations into the fire watch procedure and the administrative controls provided for inoperable fire protection equipment to be acceptable.

In a recent self-assessment of the fire protection program, the licensee identified that fire drill evaluators were credited as having participated in the drills. The licensee committed to revise the procedure so that only personnel responding in turnout gear will be credited as having participated in future fire drills.

a. Conclusion

The inspectors concluded that the fire protection procedures reviewed provided adequate fire protection controls and were adequately implemented by station personnel.

F4 Fire Protection Staff Knowledge and Performance

a. Inspection Scope (64704)

On December 2, 1998, the inspector observed an unannounced fire drill in the 2/3 crib house and the subsequent drill critique.

b. Observations and Findings

The brigade leader and members arrived in an emergency response vehicle at the west side of the crib house with their turnout gear in the vehicle. The brigade leader initiated a security check to ensure that no one was in the fire area. Two brigade members entered the area with dry chemical extinguishers. However, the drill evaluator had not informed the responding brigade members of the stimulated conditions in the room. Therefore, two brigade members entered into the area standing up instead of stooping low on the floor. The first two brigade members subsequently identified a potential fire exposure because the simulated fire was in front of the diesel driven fire pump day tank. The brigade leader contacted the control room to secure the 3A circulating water pump which was in the vicinity of the day tank. The two brigade members formed a hose team and simulated actions to cool the potential exposure. After the first team exited the area, two other brigade members entered the area to search for potential victims and simulated actions to start the room ventilation for removing smoke. The inspector observed that the actions described in the pre-fire plan were well executed during this drill.

During the critique, brigade members indicated that they need more prompting on size of fire and intensity of heat and smoke for future drills. The fire brigade function was turned over to the operations department in November 1998. Therefore, this unannounced fire drill was the first since the turnover. The inspector considered the performance acceptable.

The inspector questioned the last time the offsite fire department had participated in an onsite drill with brigade members. The licensee indicated that the last drill with the offsite fire department was in 1994. The inspector considered not having offsite fire department in onsite fire drills to be a weakness. Fire drills with the offsite fire department were important because the drills would allow the licensee to assess the following:

- The readiness of the offsite fire department which was considered the backup fire brigade to the onsite brigade.
- The effectiveness of communication between the offsite fire department and the onsite personnel.
- The ability to expeditiously process offsite fire department personnel through the security gatehouse.
- The transfer of command and control between the offsite and onsite brigade members.

Dresden Fire Protection Procedure (DFPP) 4123-11, "Emergency Response Drills," Revision 6, required that fire drills should include offsite fire department participation where possible. In addition, the procedure stated that at least annually the offsite fire department will be offered the opportunity to participate in any of the fire drills. The licensee could not locate the annual invitation letters. In a memorandum dated December 14, 1998, the Fire Chief in the Coal City fire protection district stated that the licensee had consistently invited the fire department to participate in training sessions and exercises at the facility in the past. Therefore, this was not a violation of any procedural requirement. The licensee initiated a predefined activity in the surveillance program to remind the fire marshal to annually invite the offsite fire department to participate in site drills.

c. Conclusion

The performance of the observed drill was good and the brigade team adequately executed the guidelines listed in the fire pre-plan for that area. One minor weakness was noted where the evaluator did not provide information of the fire size, heat intensity, and relative visibility from the smoke to the brigade members so that brigade members could respond in a realistic manner. A second weakness was noted where the fire drills had not included the offsite fire department since 1994.

F7 Quality Assurance in Fire Protection Activities

The inspector reviewed the QA audit reports from 1996 to 1998 and a recently performed self-assessment using guidance from Temporary Instruction 2515/XXX, "Fire Protection Functional Inspection." The associated audit checklists were also reviewed to determine the scope of each audit performed. The inspector considered the checklists used to be thorough and the audit reports contained substantive findings. There were several PIFs issued as a result of the self-assessment that mirrored the NRC fire protection functional inspection (FPFI). The licensee also completed the evaluation of 206 applicable Appendix R technical issues identified at Quad Cities. The inspector did not review the report because it was still in draft. The report evaluating the 206 issues for applicability at Dresden and resolutions to the PIFs initiated from the self-assessment will be reviewed in the future.

V. Management Meetings

X1 Exit Meeting Summary

The inspector presented the inspection results to the members of licensee management at the conclusion of the inspection on December 3, 1998. The licensee acknowledged the findings presented.

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

PARTIAL LIST OF PERSONS CONTACTED

Licensee

P. Swafford	Station Manager
P. Chabot	Engineering
S. Chingo	Staff Engineer
M. Dillion	Fire Protection Engineer
R. Kelly	NRC Coordinator
J. Lindsey	Operations Training Coordinator
A. Lintakas	Program Engineer
R. Peak	Engineering Design Manager
P. Planning	Engineering Programs Supervisor
D. Roberts	Staff Engineer
D. Schupp	Operations
F. Spangenberg	Regulatory Assurance Manager
B. Speek	Nuclear Oversight Auditor
J. Steiner	Fire Protection Engineer

NRC

K. Riemer	Senior Resident Inspector
D. Roth	Resident Inspector
B. Dickson	Resident Inspector
R. Lerch	Project Engineer

INSPECTION PROCEDURES USED

IP 64704 Fire protection

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-237/249-98029-01	URI	Lack of fire stops and fire retardant coating for redundant cables on Units 2 and 3 turbine building ground floor elevation

LIST OF ACRONYMS USED

CDF	Core Damage Frequency
CFR	Code of Federal Regulation
DAP	Dresden Administrative Procedure
DATR	Dresden Administrative Technical Requirements
DFPP	Dresden Fire Protection Procedure
DFPS	Dresden Fire Protection Surveillance Procedure
DRS	Division of Reactor Safety
FPFI	Fire Protection Functional Inspection
FSAR	Final Safety Analysis Report
IPEEE	Individual Plant Examination-External Event
LER	Licensee Event Report
MCC	Motor Control Center
MOV	Motor Operated Valve
PIF	Problem Identification Form
QA	Quality Assurance
SER	Safety Evaluation Report
URI	Unresolved Item

LIST OF DOCUMENTS REVIEWED

- NFPA 13-1968 Edition, "Standard for the Installation of Sprinkler Systems"
- DHP 0220-02, "Compressed Gas Cylinder Controls," Revision 2, dated April 17, 1998.
- DHP 0230-01, "Control of Hot Work," Revision 3, dated April 20, 1996.
- DHP 0230-02, "Fire Protection for Transient Combustibles," Revision 02, dated April 9, 1998.
- DES 4153-03, "Unit 2(3) Balance of Plant Emergency Lighting Routine Inspection, "Revision 11.
- DES 4153-04, "Emergency Lighting Discharge Test," Revision 11, dated November 3, 1998.
- DFPP 4100-03, "Fire Watch Procedure," dated February 19, 1998.
- DFPS 4114-04, "Fire Extinguisher Maintenance Inspection," Revision 9.
- DFPS 4114-05, "Fire Hose Inspection/Service Test," Revision 13.
- DFPS 4114-12, "Fire Equipment Cart Inspection," Revision 5, dated March 20, 1997.
- DFPS 4175-05, "Safety Related Electrical Cabinets Visual Inspection," Revision 2.
- DFPS 4175-07, "Fire Door/Oil Spill Barrier Surveillance," Revision 9.
- DFPS 4175-13, "Fire Door Maintenance," Revision 3.
- DFPS 4183-05, "Unit 3 Heat/Smoke Detector Operability Test, "Revision 8.
- DAP 03-12, "Plant Cleaning Program and in Pant Permanent Storage Areas," Revision 2, dated February 24, 1995.
- DAP 07-48, "Control of Lay Down, Storage Areas, and Equipment in Use," Revision 6, dated September 25, 1998.
- DOA 0010-10. "Fire/Explosion," Revision 05, dated April 24, 1996.

TAB 23

June 19, 2002

Mr. John L. Skolds, President
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: DRESDEN NUCLEAR POWER STATION
NRC INSPECTION REPORT 50-237/02-06(DRS); 50-249/02-06(DRS)

Dear Mr. Skolds:

On May 10, 2002, the NRC completed an inspection at your Dresden Nuclear Power Station facility. The enclosed report documents the inspection findings which were discussed on May 10, 2002, with Mr. R. Hovey and other members of your staff.

The inspection examined the effectiveness of activities conducted under your license as they related to implementation of your NRC approved Fire Protection Program. The inspection consisted of a selected examination of design drawings, calculations, analyses, procedures, audits, field walkdowns, and interviews with personnel.

Based on the results of this inspection, the inspectors identified one issue of very low safety significance (Green). This issue was determined to involve a violation of NRC requirements. However, because of its very low safety significance and because the issue has been entered into your corrective action program, the NRC is treating this issue as a Non-Cited Violation, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny this Non-Cited Violation, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Dresden Nuclear Power Station facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your responses will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA by Roy Caniano Acting For/

John A. Grobe, Director
Division of Reactor Safety

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

Enclosure: Inspection Report 50-237/02-06(DRS); 50-249/02-06(DRS)

cc w/encl: Site Vice President - Dresden Nuclear Power Station
Dresden Nuclear Power Station Plant Manager
Regulatory Assurance Manager - Dresden
Chief Operating Officer
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional Operating Group
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing - Mid-West Regional Operating Group
Manager Licensing - Dresden and Quad Cities
Senior Counsel, Nuclear, Mid-West Regional Operating Group
Document Control Desk - Licensing
M. Aguilar, Assistant Attorney General
Illinois Department of Nuclear Safety
State Liaison Officer
Chairman, Illinois Commerce Commission

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Director Licensing - Mid-West Regional Operating Group
Manager Licensing - Dresden and Quad Cities
Senior Counsel, Nuclear, Mid-West Regional Operating Group
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M. Aguilar, Assistant Attorney General
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U.S. NUCLEAR REGULATORY COMMISSION
REGION III

Docket Nos: License Nos:	50-237; 50-249 DPR-19; DPR-25
Report No:	50-237/02-06(DRS); 50-249/02-06(DRS)
Licensee:	Exelon Generation Company
Facility:	Dresden Nuclear Power Station, Units 2 and 3
Location:	6500 North Dresden Road Morris, IL 60450
Dates:	April 22 through May 10, 2002
Lead Inspector:	R. Langstaff, Senior Reactor Inspector Mechanical Engineering Branch
Inspectors:	D. Chyu, Reactor Inspector Electrical Engineering Branch R. Daley, Reactor Inspector Electrical Engineering Branch
Approved By:	Ronald N. Gardner, Chief Electrical Engineering Branch Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000237-02-06(DRS), 05000249-02-06(DRS), on 04/22-05/10/02-01, Exelon Generation Company, Dresden Nuclear Power Station. Fire Protection Triennial.

The inspection was conducted by a team of three Region III inspectors. The inspection identified one Non-Cited Violation (NCVs). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609m, "Significance Determination Process." The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/reactors/operating/oversight.html.

A. Inspector-Identified Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified, that in the event of a fire, reactor water level could decrease to below the top of active fuel. Although the licensee had taken credit for tripping the reactor recirculation pumps, the procedures for alternative safe shutdown did not direct operators to trip the pumps. The additional heat load from the reactor recirculation pumps would cause additional reactor coolant to be lost through the safety relief valves resulting in a lower reactor water level than assumed. The failure to ensure reactor water level would remain above the top of active fuel is a violation of 10 CFR Part 50, Appendix R, Section III.L.2.b.

  The finding was greater than minor because the failure to ensure that reactor water level would remain above the top of active fuel resulted in a reduction of safety margin. The finding was determined to be Green because the water level would remain above two thirds core height and core damage would not occur. Because the finding was of very low safety significance, and the finding was captured in the licensee's corrective action system, this finding is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (Section 1R05.1.b.1).

Report Details

Summary of Plant Status: Both Unit 2 and Unit 3 were operated at or near 100 percent power throughout the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events and Mitigating Systems

1R05 Fire Protection (71111.05)

The purpose of this inspection was to review the Dresden Nuclear Power Station fire protection program for selected risk-significant fire areas. Emphasis was placed on verifying that the post-fire safe shutdown capability and the fire protection features were maintained free of fire damage to ensure that at least one post-fire safe shutdown success path was available. The inspection was performed in accordance with the NRC regulatory oversight process using a risk-informed approach for selecting the fire areas and attributes to be inspected. The lead inspector used the Dresden Individual Plant Examination for External Events (IPEEE) to choose several risk-significant areas for detailed inspection and review. The fire areas and zones chosen for review during this inspection were:

Fire Area	Fire Zone	Description of Fire Zones Reviewed Within Fire Area
TB-I	8.2.5.A	Unit 2 North Trackway/Switchgear Area
	9.0.A	Unit 2 Diesel Generator
TB-V	2.0	Control Room
	6.2	Auxiliary Electric Equipment Room (AEER)

The primary focus for this inspection was on the safe shutdown procedures and safe shutdown methodology for fire area TB-V and the fire protection features for fire zone 6.2, i.e., the AEER. To a lesser extent, the fire protection features for fire zones 8.2.5.A and 9.0.A of fire area TB-I were also reviewed. The determination of license commitments and changes to the fire protection program were reviewed for both fire areas.

.1 Systems Required to Achieve and Maintain Post-Fire Safe Shutdown

10 CFR Part 50, Appendix R, Section III.G.1, required the licensee to provide fire protection features that were capable of limiting fire damage to structures, systems, and components important to safe shutdown. The structures, systems, and components that were necessary to achieve and maintain post-fire safe shutdown were required to be protected by fire protection features that were capable of limiting fire damage to the structures, systems, and components so that:

- One train of systems necessary to achieve and maintain hot shutdown conditions from either the control room or emergency control station(s) was free of fire damage; and
- Systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station(s) could be repaired within 72 hours.

Specific design features for ensuring this capability were specified by 10 CFR Part 50, Appendix R, Section III.G.2.

a. Inspection Scope

The inspectors reviewed the plant systems required to achieve and maintain post-fire safe shutdown to determine if the licensee had properly identified the components and systems necessary to achieve and maintain safe shutdown conditions for each fire zone selected for review. Specifically, the review was performed to determine the adequacy of the systems selected for reactivity control, reactor coolant makeup, reactor heat removal, process monitoring, and support system functions. This review included the fire protection safe shutdown analysis.

The inspectors also reviewed the operators' ability to perform the necessary manual actions for achieving safe shutdown including a review of procedures, accessibility of safe shutdown equipment, and the available time for performing the actions.

The inspectors reviewed the updated final safety analysis report and the licensee's engineering and/or licensing justifications (e.g., NRC guidance documents, license amendments, technical specifications, safety evaluation reports, exemptions, and deviations) to determine the licensing basis.

b. Findings

b.1 Performance Criteria for Achieving Shutdown Conditions Not Met

The inspectors identified a Non-Cited Violation for failure to meet the performance goal of maintaining the reactor coolant level above the top of the core as required for an alternative shutdown area by 10 CFR Part 50 Appendix R, Section III.L.2.b.

The Dresden Nuclear Power Station safe shutdown analysis for area TB-V assumed that reactor vessel makeup would be restored within 30 minutes of the analyzed fire event. The licensee had calculated that without makeup to the vessel, reactor vessel water level would decrease to the top of active fuel in 32 minutes due to loss of inventory thereby providing a margin of 2 minutes.

The Dresden Nuclear Power Station analysis which determined that vessel level would decrease to the top of active fuel within 32 minutes assumed that the recirculation pumps would be tripped off within 10 minutes of the fire event. However, the procedure for the fire scenario, DSSP 0100-CR, "Hot Shutdown Procedure - Control Room Evacuation," did not contain a step for tripping the recirculation pumps. Consequently, if this fire had occurred, the recirculation pumps could have continued to run contributing additional heat (approximately nine megawatts) to the reactor coolant system. This additional heat would have caused more inventory to be lost from the reactor coolant system through the safety relief valves. During the inspection, the licensee had calculated that the extra loss of inventory could have resulted in the reactor vessel water level decreasing to the top of active fuel in 29 minutes, i.e., before reactor vessel makeup was assumed to be established.

10 CFR Part 50, Appendix R, Section III.L.2.b, requires that the reactor coolant makeup function shall be capable of maintaining the reactor coolant level above the top of the core for boiling water reactors. Dresden Nuclear Power Station is a boiling water reactor and fire area TB-V was an alternative shutdown area for which the licensee was required to comply with Section III.L of 10 CFR Part 50, Appendix R. The inspectors determined that the finding associated with the failure to ensure that reactor coolant level would remain above the top of active fuel in the event of a fire was greater than minor because the margin for preventing core damage was reduced to the point that the performance criteria of 10 CFR Part 50, Appendix R, Section III.L.2 would not be met. The inspectors determined that the finding was of very low safety significance because the reactor coolant level would have remained above two thirds core height and core damage would not have occurred. The failure to ensure that reactor coolant level would remain above the top of active fuel in the event of a fire is a violation of 10 CFR Part 50, Appendix R, Section III.L.2.b. This violation is associated with a finding that is characterized by the Significance Determination Process as having very low risk significance (i.e., Green) and is being treated as a Non-Cited Violation (NCV), consistent with Section VI.A.1 of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as Condition Report (CR) 00105408 (NCV 50-237/02-06-01; 50-249/02-06-01).

b.2 <u>Emergency Diesel Generator Testing</u>

During review of emergency power supplies used for safe shutdown, the inspectors determined that load testing of the 2/3 emergency diesel generator (EDG) at Dresden Nuclear Power Station was based upon the continuous load rating of 2600 kilowatts (kW). The continuous rating of the 2/3 EDG for Dresden Nuclear Power Station historically was bounded by the loads predicted for a loss of coolant accident (LOCA) coincident with a loss of offsite power (LOOP). However, because of recent changes to the predicted loads in the EDG loading calculation for Dresden Nuclear Power Station, the revised LOOP-LOCA predicted loads of 2677 kW for the 2/3 EDG exceeded the EDG continuous load rating. As a result, from a design basis accident perspective, the EDG testing requirements at Dresden Station were non-conservative. The inspectors reviewed a recent surveillance for the 2/3 EDG and did not identify any violations of surveillance requirements as specified by Technical Specification Sections, SR 3.8.1.3 and SR 3.8.1.15. The inspectors noted that Technical Specification Sections SR 3.8.1.3, SR 3.8.1.11, and SR 3.8.1.15 used a load band of 2340 kW to 2600 kW based on 90 to 100 percent of the 2/3 EDG continuous ratings of 2600 kW as basis for acceptability. The inspectors also noted that, for the surveillance reviewed, the 2/3 EDG had been tested within 90 to 100 percent of the predicted design basis loads as well. However, the inspectors questioned whether the Technical Specification surveillance requirements should have been revised to reflect the design basis loads which exceeded the EDG continuous ratings. This issue will be tracked as unresolved item (URI) pending further NRC review (URI 50-237/02-06-02; 50-249/02-06-02).

.2 Fire Protection of Safe Shutdown Capability

10 CFR Part 50, Appendix R, Sections III.G.2, required separation of cables and equipment and associated circuits of redundant trains by a fire barrier having a three hour rating. If the requirements cannot be met, then alternative or dedicated shutdown capability and its associated circuits, independent of cables, systems or components in the area, room, or zone under consideration should be provided (Section III. G.3).

a. Inspection Scope

For each of the selected fire areas, the inspectors reviewed the licensee's safe shutdown analysis to ensure that at least one post-fire safe shutdown success path was available in the event of a fire. This included a review of manual actions required to achieve and maintain hot shutdown conditions and make the necessary repairs to reach cold shutdown within 72 hours. The inspectors also reviewed procedures to verify that adequate direction was provided to operators to perform these manual actions. Factors, such as timing, access to the equipment, and the availability of procedures, were considered in the review.

The inspectors also evaluated the adequacy of fire suppression and detection systems, fire area barriers, penetration seals, and fire doors to ensure that at least one train of safe shutdown equipment was free of fire damage. To do this, the inspectors observed the material condition and configuration of the installed fire detection and suppression systems, fire barriers, and construction details and supporting fire tests for the installed fire barriers. In addition, the inspectors reviewed license documentation, such as deviations, detector placement drawings, fire hose station drawings, carbon dioxide pre-operational test reports, smoke removal plans, fire hazard analysis reports, safe shutdown analyses, and National Fire Protection Association (NFPA) codes to verify that the fire barrier installations met license commitments.

b. Findings

No findings of significance were identified.

.3 Post-Fire Safe Shutdown Circuit Analysis

10 CFR Part 50, Appendix R, Section III.G.1, required that structures, systems, and components important to safe shutdown be provided with fire protection features capable of limiting fire damage to ensure that one train of systems necessary to achieve and maintain hot shutdown conditions remained free of fire damage. Options for providing this level of fire protection were delineated in 10 CFR Part 50, Appendix R, Section III.G.2. Where the protection of systems whose function was required for hot shutdown did not satisfy 10 CFR Part 50, Appendix R, Section III.G.2, an alternative or dedicated shutdown capability and its associated circuits, was required to be provided that was independent of the cables, systems, and components in the area. For such areas, 10 CFR Part 50, Appendix R, Section III.L.3, specifically required the alternative or dedicated shutdown capability to be physically and electrically independent of the specific fire areas and capable of accommodating post-fire conditions where offsite power was available and where offsite power was not available for 72 hours.

a. Inspection Scope

On a sample basis, the inspectors investigated the adequacy of separation provided for the power and control cabling of redundant trains of shutdown equipment. This investigation focused on the cabling of selected components in systems important for safe shutdown. The inspectors' review also included a sampling of components whose inadvertent operation due to fire may adversely affect post-fire safe shutdown capability. The purpose of this review was to determine if a single exposure fire, in one of the fire areas selected for this inspection, could prevent the proper operation of both safe shutdown trains.

b. Findings

No findings of significance were identified.

.4 Alternative Safe Shutdown Capability

10 CFR Part 50, Appendix R, Section III.G.1, required that structures, systems, and components important to safe shutdown be provided with fire protection features capable of limiting fire damage to ensure that one train of systems necessary to achieve and maintain hot shutdown conditions remained free of fire damage. Options for providing this level of fire protection were delineated in 10 CFR Part 50, Appendix R, Section III.G.2. Where the protection of systems whose function was required for hot shutdown did not satisfy 10 CFR Part 50, Appendix R, Section III.G.2, an alternative or dedicated shutdown capability independent of the area under consideration was required to be provided. Additionally, alternative or dedicated shutdown capability must be able to achieve and maintain hot standby conditions and achieve cold shutdown conditions within 72 hours and maintain cold shutdown conditions thereafter. During the post-fire safe shutdown, the reactor coolant process variables must remain within those predicted for a loss of normal alternating current (AC) power, and the fission product boundary integrity must not be affected (i.e., no fuel clad damage, rupture of any primary coolant boundary, or rupture of the containment boundary).

a. Inspection Scope

The inspectors reviewed the licensee's systems required to achieve alternative safe shutdown to determine if the licensee had properly identified the components and systems necessary to achieve and maintain safe shutdown conditions. The inspectors also focused on the adequacy of the systems to perform reactor pressure control, reactivity control, reactor coolant makeup, decay heat removal, process monitoring, and support system functions.

b. Findings

No findings of significance were identified.

.5 Operational Implementation of Alternative Shutdown Capability

10 CFR Part 50, Appendix R, Section III.L.2.d, required that the process monitoring function should be capable of providing direct readings of the process variables necessary to perform and control the functions necessary to achieve reactivity control, reactor coolant makeup, and decay heat removal.

a. Inspection Scope

The inspectors performed a walkdown of a sample of the actions defined in procedure DSSP 0100-CR, "Hot Shutdown Procedure - Control Room Evacuation," which was the procedure for performing a plant alternative shutdown from outside the control room for fire area TB-V. The inspectors verified that operators could reasonably be expected to perform the procedure actions within the identified applicable plant shutdown time requirements and that equipment labeling was consistent with the procedure.

The inspectors' reviews of the adequacy of communications and emergency lighting associated with these procedures are documented in Sections 1R05.6 and 1R05.7 of this report.

b. Findings

No findings of significance were identified.

.6 Communications

For a fire in an alternative shutdown fire area such as the cable spreading room, control room evacuation is required and a shutdown is performed from outside the control room. Radio communications are relied upon to coordinate the shutdown of both units and for fire fighting and security operations. 10 CFR Part 50, Appendix R, Section III.H., required that equipment provided for the fire brigade include emergency communications equipment.

a. Inspection Scope

The inspectors reviewed the adequacy of the communication system to support plant personnel in the performance of alternative safe shutdown functions and fire brigade duties.

b. Findings

No findings of significance were identified.

.7 Emergency Lighting

10 CFR Part 50, Appendix R, Section III.J., required that emergency lighting units with at least an eight-hour battery power supply be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto.

a. Inspection Scope

The inspectors performed a walkdown of a sample of the actions defined in procedure DSSP 0100-CR. As part of the walkdowns, the inspectors verified that sufficient emergency lighting existed for access and egress to areas and for performing necessary equipment operations.

b. Findings

No findings of significance were identified.

.8 Cold Shutdown Repairs

10 CFR Part 50, Appendix R, Section III.L.5, required that equipment and systems comprising the means to achieve and maintain cold shutdown conditions should not be damaged by fire; or the fire damage to such equipment and systems should be limited so that the systems can be made operable and cold shutdown achieved within 72 hours. Materials for such repairs shall be readily available onsite and procedures shall be in effect to implement such repairs.

a. Inspection Scope

The inspectors reviewed the licensee's procedures to determine if any repairs were required to achieve cold shutdown. The inspectors determined that the licensee did require repair of some equipment to reach cold shutdown based on the safe shutdown methods used. The inspectors reviewed the procedures for adequacy.

b. Findings

No findings of significance were identified.

.9 Fire Barriers and Fire Zone/Room Penetration Seals

10 CFR Part 50, Appendix R, Section III.M, required that penetration seal designs be qualified by tests that are comparable to tests used to rate fire barriers.

a. Inspection Scope

The inspectors reviewed the test reports for three-hour rated barriers installed in the plant and performed visual inspections of selected barriers to ensure that the barrier installations were consistent with the tested configuration.

b. Findings

No findings of significance were identified.

.10 Fire Protection Systems, Features, and Equipment

a. Inspection Scope

The inspectors reviewed the material condition, operations lineup, operational effectiveness, and design of fire detection systems, fire suppression systems, manual fire fighting equipment, fire brigade capability, and passive fire protection features. The inspectors reviewed deviations, detector placement drawings, fire hose station drawings, halon and carbon dioxide (CO_2) system pre-operational test reports, and fire hazard analysis reports to ensure that selected fire detection systems, sprinkler systems, portable fire extinguishers, and hose stations were installed in accordance with their design, and that their design was adequate given the current equipment layout and plant configuration.

b. Findings - AEER Fixed Suppression Systems

The inspectors identified one finding with respect to the Halon and CO_2 fixed suppression systems in the AEER. The finding is being treated as an unresolved item pending NRC review of whether the inspectors' positions represent a backfit as described by 10 CFR 50.109, Backfitting.

b.1 General Information

The AEER at Dresden Station is located directly below the control room. The AEER contained electrical switchgear and cabinets at the floor level with a cable spreading area above the electrical switchgear and cabinets. Additionally, the fire area envelope of the AEER included a portion of a cable tunnel and a computer room. Fixed suppression for the AEER was provided by both an automatically actuated Halon suppression system and a manually actuated CO_2 suppression system.

b.2 Historical Background

In the Branch Technical Position (BTP) APCSB 9.5-1, Appendix A, review documented in the Safety Evaluation Report (SER), dated March 22, 1978, the NRC requested additional information in the form of design details to ensure that the design was acceptable prior to actual implementation of the automatic Halon suppression system and the manually actuated CO_2 suppression system for the AEER and computer room.

The licensee submitted the AEER gas suppression system hydraulic calculations (further discussed below) and design drawings in a letter dated September 28, 1978. As a result of the NRC review, the NRC requested, by letter dated October 27, 1980, that additional nozzles be provided in the underfloor of the computer room and in the small tunnel area. By letter dated February 6, 1981, the licensee committed to provide discharge nozzles in the underfloor area of the computer room and in the tunnel area of the AEER. Based on the licensee's commitment, the NRC concluded in a SER dated February 12, 1981, that the gas suppression systems were acceptable.

In 1982, the NRC conducted a review of the Halon and CO_2 systems. The results of this review were documented in Inspection Report 50-237/82-02; 50-249/82-02 as an open item. The following is an excerpt from the inspection report:

> The inspector toured the new HALON CO_2 fire protection system to verify installation and equipment operability, and found the equipment satisfactory. A review of the station documentation package for the modification indicated that adequate controls were used for procurement, installation, design, and shop testing of equipment. Records of onsite testing for correctness of installation and equipment operability were largely missing from the documentation. The licensee included a memorandum to file in the package to note this fact; however, the overall adequacy of the equipment (operability, etc.) has not been documented.

In 1984, the above open item was administratively closed out with the following discussion:

> The licensee acquired a copy of the installation test results from the manufacturer and placed it in the modification package. Discussion with the fire marshal revealed that the licensee conducted a review of the system against as-built drawings and reviewed the design philosophy, and found them to be as required.

During the Appendix R review process in the late 1980's, the licensee submitted a copy of their fire hazard analysis (FHA), Amendment 2, dated February 1986. The submitted FHA included a comparison table of guidelines of Appendix A to BTP APCSB 9.5-1 and whether the licensee met or the reason for deviating from the guidelines. The licensee indicated the following in the FHA:

NRC Position in Guidelines of Appendix A to BTP APCSB 9.5-1	Implementation of Justification for Noncompliance (Licensee Position)
E.4 <u>Halon Suppression Systems</u> The use of Halon fire extinguishing agents should as a minimum comply with the requirements of NFPA 12A and 12B, "Halogenated Fire Extinguishing Agent System - Halon 1301 and Halon 1211."	Comply with intent: Dresden Units 2 and 3 utilize Halon 1301 for protection of the Auxiliary Electric Equipment Room. This installation meets the requirement of NFPA 12A. NFPA 12A was reviewed and deviations justified (FPPDP Volume 5)

E.5 Carbon Dioxide Suppression Systems The use of carbon dioxide extinguishing systems should as a minimum comply with the requirements of NFPA, "Carbon Dioxide Extinguishing Systems." Particular consideration should also be given to: (a) minimum requirement CO_2 concentration and soak time;	Partial comply: (a) NFPA 12 was used in design although installation acceptance tests were not specifically performed.
(b) toxicity of CO_2;	(b) all carbon dioxide systems have predischarge alarms.
(c) possibility of second thermal shock (cooling damage);	(c) Nozzles do not discharge directly on equipment
(d) offsetting requirements for venting during CO_2 injection to prevent overpressurization versus sealing to prevent loss of agent;	(d) See part (a).
(e) design requirements from overpressurization.	(e) See part (a).

The inspectors reviewed the Fire Protection Program Documentation Package (FPPDP) Volumes 8 and 9 which documented the licensee's NFPA code conformance review. For gaseous suppression systems, the licensee did not identify any deviations from the NFPA codes regarding a lack of acceptance testing for CO_2 and Halon systems installed in AEER.

During the NRC Appendix R onsite audit conducted in 1988 (documented in Inspection Report 50-237/88010; 50-249/88012), the licensee had provided total flooding CO_2 suppression systems for the diesel generator rooms, day tank rooms, and the AEER. During that inspection, the NRC requested to review the CO_2 discharge test result for the emergency diesel generator rooms. The NRC identified the lack of concentration tests documented for these areas and requested the licensee to perform discharge tests for the rooms reviewed. The licensee subsequently completed the concentration tests for the Unit 2, Unit 2/3, and Unit 3 EDG rooms in November 1988, January 1989, and June 1988, respectively.

b.3 Gas Suppression System Design - Concentration and Soak Time

The inspectors reviewed the sizing calculations for the Halon and CO_2 systems for the AEER. The design specifications for the gas suppression systems were as follows:

	Halon	CO_2
Concentration	5%	50%
Soak Time	10 minutes	10 minutes

The licensee stated during this inspection that the design for Halon and CO_2 systems with the above specifications was to extinguish surface and deep-seated fires, respectively. The vendor stated in the CO_2 calculation for AEER that the CO_2 system was designed for a deep seated fire hazard. The inspectors noted that the design concentration and soak times for the Halon system were consistent with Halon systems designed for suppression surface fires. Specifically, Section 2420 of NFPA 12A-1973, "Halogenated Fire Extinguishing Agent Systems," the code of record for Dresden stated:

> These fires [solid surface fires] are easily extinguished with low concentration (e.g., 5%) of Halon 1301. Although glowing embers may remain at the surface of the fuel following extinguishment of flames, these embers will be completed extinguished with a short time (e.g., 10 minutes).

However, the inspectors could not determine that the concentration and soak time for CO_2 system were adequate to suppress a deep-seated fire. NFPA 12-1973, "Carbon Dioxide Extinguishing Systems," considered as the code of record, provided the following requirements for deep seated fires:

Section 1322	These plans shall contain sufficient detail to enable the authority having jurisdiction to evaluate the hazard or hazards and to evaluate the effectiveness of the system.
Section 241	The quality of carbon dioxide for deep seated type fires is base on fairly tight enclosure because the concentration must be maintained for a substantial period of time to assure complete extinguishment. Any possible leakage shall be given special consideration since no allowance is included in the basic flooding factors.
Section 2421	The flooding factor for dry electrical, wiring insulation hazards in general was established to be at 50%.
App. A-21	For deep-seated fires the critical concentration required for extinguishment is less definite and has in general been established by practical test work.

NFPA 12-1973 did not specify the soak time for a deep-seated fire. Although the calculation for CO_2 was submitted to the NRC during the Appendix A to BTP APCSB 9.5-1 review as discussed above, the licensee did not provide justification, through either empirical or experimental data, that the soak time of 10 minutes was adequate to suppress a deep-seated fire. During this inspection, the licensee stated their position was that the NRC had approved the concentration and soak time for both the Halon and CO_2 systems because the NRC had reviewed the design calculations for both systems in the AEER and had no concerns except for the placement of discharge nozzles. Although the calculations were sent to the NRC, the inspectors could not determine whether the NRC had granted tacit approval for the Halon and CO_2 system concentration and soak times. The inspectors noted that the licensee had not submitted a technical justification which supported the design concentrations and soak times for suppressing a deep-seated fire to the NRC during either the Appendix A review or this inspection.

The Halon and CO_2 systems were approved for installation in February 1978 (Mod M12-2/3-7639). Installation of the system was completed on June 4, 1979 and QA approval on February 16, 1981. The licensee did not commit to install additional nozzles in the sub-floor area of the computer room and in the small area of the cable tunnel until February 6, 1981. During this inspection, the licensee could not determine when additional nozzles were installed and speculated that the nozzle addition was completed as part of the modification.

Based on fire tests conducted by Sandia National Laboratory, the NRC determined that the minimum concentrations and soak times required to suppress a deep-seated electrical fire involving IEEE-383 rated cables were as outlined below. (See Table 9 of NUREG/CR-3656, "Evaluation of Suppression Methods for Electrical Cable Fires," dated October 1986, for additional information.)

	Halon	CO_2
Concentration	6%	50%
Soak Time	15 minutes	15 minutes

During this inspection, the licensee stated that some IEEE [Institute of Electrical and Electronics Engineers] -383 rated cables were installed in the AEER at the time the Halon and CO_2 systems were installed. The licensee estimated that at the time of this inspection, approximately 24% of the cables installed in the AEER were IEEE-383 cables. The majority of IEEE-383 cables had been installed during the late 1980s and early 1990s.

Based on the above information, the inspectors were not able to conclude that either the installed Halon system or installed CO_2 system was capable of a extinguishing fire in the AEER.

b.4 <u>Lack of Discharge Testing for the Gas Suppression Systems</u>

The inspectors noted that there were no discharge tests performed to ensure that the required concentration and soak time were achievable with the room configuration.

For the Halon systems, the inspectors noted that NFPA 12A-1973 stated the following testing requirements:

Section 1310 The specifications shall include all pertinent items necessary for the proper design of the system such as the designation of the authority having jurisdiction, variance from the standard to be permitted by the authority having jurisdiction and the type and extend of the approval testing to be performed after installation of the system.

Section 1340 The completed system shall be tested by qualified personnel to meet the approval of the authority having jurisdiction. These tests shall be adequate to determine that the system has been properly installed and will function as intended.

App. A-1340 A suitable discharge test or concentration analysis should be made when conditions prevail that make it difficult to determine adequately the system requirement or design

The inspectors noted that the purpose of Appendix A in NFPA-12A was to explain the basic principles, agent and equipment characteristics, and maintenance and installation practices. As discussed on Page 6 of NFPA 12A, the word "shall" was intended to indicate requirements and the word "should" was intended to indicate recommendations or that which was advised but not required. As such, the inspectors considered the wording of Section 1340 to take precedence over the recommendations specified in Section A-1340. The inspectors did not consider it possible to adequately determine that a Halon system is properly installed and will function as intended without measuring concentrations resulting from a full discharge test.

With respect to the CO_2 system, NFPA 12-1973 stated the following requirements:

Section 134 The completed system shall be tested by qualified personnel to meet the approval of the authority having jurisdiction. These tests shall be adequate to determine that the system has been properly installed and will function as intended.

Section 213 Total flooding systems shall be designed, installed, tested and maintained in accordance with the applicable requirements in the previous chapter and with the additional requirements set forth in this chapter.

The inspectors considered the word "tests," as used in the NFPA code, to include a discharge test. The NRC considers that a discharge test is necessary to demonstrate that total flooding gaseous suppression systems have been properly installed and will function as intended. In this case, the Halon and CO_2 systems depend heavily on a reasonably well enclosed space in order to minimize losses of the extinguishing medium. Additionally, the AEER contains significant fire hazards (i.e., electrical cables) in the upper portions of the room. The inspectors noted that it would be more difficult to establish and maintain minimum concentrations in the upper portions of the room because both Halon and CO_2 are heavier than air and would tend to sink to the lower portions of the room. Without a discharge test, there is no reasonable assurance that the enclosure is adequate to enable the required concentration to be built up and maintained at all necessary elevations for the required period of time to ensure the effective extinguishment of the fire. Based on review of the codes of record for both the Halon and CO_2 systems, the inspectors determined that neither system had been adequately tested to demonstrate that the system had been properly installed and will function as intended.

During this inspection, the licensee stated that the design review performed by the NRC during the Appendix A to BTP APCSB 9.5-1 review, the Appendix R review, and the previous NRC inspection granted the approval for the lack of discharge testing. The inspectors noted the following:

- During the Appendix A to BTP APCSB 9.5-1 review, the licensee did not specifically request not to perform discharge tests for both systems.

- In 1982 and 1984, Region III inspectors did review the modification package for installation of Halon and CO_2 systems. At that time, the majority of package documentation was missing and the open item was administratively closed out based on discussion with plant personnel.

- During the Appendix R review, the licensee did inform the NRC that the installation acceptance test was not performed for the CO_2 system. During the Appendix R inspection, the inspectors noted the lack of discharge testing for the EDG rooms and requested the licensee to perform such tests accordingly. The AEER was not specifically reviewed during that inspection because it was not part of the inspection sample. The licensee did not inform the NRC that discharge testing was not performed for the Halon system.

The inspectors determined that there was no explicit request, recognition, or acknowledgment for a lack of discharge testing for both Halon and CO_2 systems by either the licensee or the NRC during plant licensing. As such, the licensee was expected to comply with design basis requirements set forth in Guidelines of Appendix A to BTP APCSB 9.5-1 which required the Halon and CO_2 systems to comply with the requirements of NFPA 12A and 12, respectively. Furthermore, as discussed above, the codes of record required testing to meet the approval of the authority having jurisdiction (AHJ) and to demonstrate the systems were properly installed and will perform their intended functions.

The inspectors reviewed the sizing calculations to see if the design could be proven acceptable analytically. The Halon calculation, dated April 1979, considered room volume for initial and extended discharges. However, the calculation failed to address the acceptability of the extended discharge since it did not address room leakage from openings such as fire doors, the east turbine building ventilation dampers, and rated fire dampers (actuated by heat instead of Halon actuation). Therefore, when the Halon system actuated, the envelope may not be sufficiently sealed to ensure the required concentration and soak time could be maintained. The inspectors identified similar issues with respect to the CO_2 system sizing calculation.

During this inspection, a contractor for the licensee performed additional calculations with the intent of demonstrated that the Halon and CO_2 systems would meet original design specifications for concentrations and soak times. The inspectors did not have the opportunity to review the calculations in detail because the calculations were completed after the on-site portion of the inspection. However, the inspectors noted the following with respect to the calculation results: (1) the Halon system would not be able to achieve a 6% concentration in the AEER; and (2) the CO_2 system would not be able to maintain a 15 minute soak time in the cable tunnel area. The inspectors did not consider the additional calculations to provide substantial assurance that either the Halon or the CO_2 suppression system was functionally capable of suppressing a deep-seated fire.

b.5 Regulatory Requirements for Suppression System in AEER

10 CFR 50.48 (a)(1) required, in part, that each operating nuclear power plant have a fire protection plan that satisfies Criterion 3 of appendix A to this part. Criterion 3 of 10 CFR Part 50, Appendix A, "Fire Protection," required, in part, fire detection and fire fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. 10 CFR 50.48 (b)(2) required, in part, that with respect to all other fire protection features covered by Appendix R, all nuclear power plants licensed to operate before January 1, 1979, must satisfy the applicable requirements of Appendix R to this part, including specifically the requirements of Sections III.G, III.J, and III.O. 10 CFR Part 50, Appendix R, Section III.G.3, required, in part, that fire detection and a fixed fire suppression system shall be installed in the area, room, or zone under consideration for alternative or dedicated shutdown capability. The AEER was an alternate shutdown area and, as such, required a fixed fire suppression system of appropriate capacity and capability. During this inspection, the inspectors could not conclusively determine that the gas suppression systems, namely Halon and CO_2 systems installed for AEER, were of appropriate capacity and capability to minimize the adverse effects of and to suppress fires in AEER which required alternative shutdown capability. This issue will remain an Unresolved Item pending further NRC review. The NRC review will specifically determine: (1) whether the lack of discharge testing was previously accepted by the NRC for the AEER Halon and CO_2 systems; and (2) whether the design concentration and soak times were previously accepted by the NRC for the AEER Halon and CO_2 systems (URI 50-237/02-06-03; 50-249/02-06-03).

.11 Compensatory Measures

a. Inspection Scope

The inspectors conducted a review to verify that adequate compensatory measures were put in place by the licensee for out-of-service, degraded or inoperable fire protection and post-fire safe shutdown equipment, systems, or features. The inspectors also verified that short term compensatory measures were adequate to compensate for a degraded function or feature until appropriate corrective actions were taken.

b. Findings

No findings of significance were identified.

.12 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the corrective action program procedures and samples of corrective action documents to verify that the licensee was identifying issues related to fire protection at an appropriate threshold and entering them in the corrective action program. The inspectors reviewed selected samples of condition reports, work orders, design packages, and fire protection system non-conformance documents.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA6 Meeting(s)

Exit Meeting

On May 10, 2002, at the conclusion of the on-site inspection activities, the inspectors presented their initial findings to Mr. R. Hovey and other members of licensee management at the Dresden Nuclear Power Station. The licensee representatives acknowledged the findings presented. The inspectors identified the proprietary information reviewed during the inspection and noted that the information would be handled accordingly. The licensee did not identify any other material reviewed during the inspection as being proprietary.

KEY POINTS OF CONTACT

Licensee

D. Bost, Station Manager
K. Bowman, Operations Manager
R. Hovey, Site Vice-President
T. Luke, Engineering Manager
B. Rybak, Acting Regulatory Assurance Manager

NRC

R. Caniano, Deputy Director, Division of Reactor Safety
R. Gardner, Chief, Electrical Engineering Branch

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

050-237/02-06-01 050-249/02-06-01	NCV	Reactor Water Level Could Drop Below Top of Active Fuel in the Event of Fire
050-237/02-06-02 050-249/02-06-02	URI	Non-Conservative Emergency Diesel Generator Testing
050-237/02-06-03 050-249/02-06-03	URI	Halon and CO_2 Fixed Suppression System Functionality Issues

Closed

050-237/02-06-01 050-249/02-06-01	NCV	Reactor Water Level Could Drop Below Top of Active Fuel in the Event of Fire

LIST OF ACRONYMS USED

AC	Alternating Current
AEER	Auxiliary Electric Equipment Room
BTP	Branch Technical Position
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CR	Condition Report
DPR	Demonstration Power Reactor
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
FHA	Fire Hazards Analysis
FPPDP	Fire Protection Program Documentation Package
IEEE	Institute of Electrical and Electronics Engineers
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination of External Events
IR	Inspection Report
kW	kiloWatt
LOCA	Loss of Coolant Accident
LOOP	Loss of Off-site Power
NCV	Non-Cited Violation
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
SER	Safety Evaluation Report
URI	Unresolved Item

LIST OF DOCUMENTS REVIEWED

The following is a list of licensee documents reviewed during the inspection, including documents prepared by others for the licensee. Inclusion on this list does not imply that NRC inspectors reviewed the documents in their entirety, but, rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort.

Analyses

FPPDP, Volume 1	Updated Fire Hazards Analysis,	Amendment 13
FPPDP, Volume 5	Safety Evaluation Reports,	Amendment 13
FPPDP, Volume 8	NFPA Code Conformance	Amendment 13
FPPDP, Volume 9	NFPA Code Conformance	Amendment 13

Calculations

88-50540	#M Fire Warp Qualification Evaluation	Revision 0
7056-00-19-5	Load Estimation of 125 VDC Buses	Revision 35
9389-46-19-3	Calculation for Diesel Generator 2/3 Loading Under Design Bases Loading Condition	Revision 2A
BSA-D-99-04	Reconstitution of Isolation Condenser Design Bases with Respect to Decay Heat Loads and Long Term Makeup Requirements	Revision 1
DRE97-0072	Dresden Station Fire Main C-Factors	Revision 3
DRE97-0105	Determination of Combustible Loading	Revision 4
DRE97-0214	Reactor Building Post-LOCA Temperature Analysis	Revision 1
DRE97-0256	Dresden Station Fire Protection System Design Basis Hydraulic Calculations	Revision 2
DRE02-0027	Isolation Condenser Area Temperature During an Appendix R Scenario Following a Fire in the Control Room	Revision 0
EC EVAL 336953	Isolation Condenser Area Average Temperature Following Station Blackout (SBO)	May 3, 2002
GE-NE-A22-00103-56-01-D	Dresden and Quad Cities Extended Power Uprate - Task T0611, Appendix R Fire Protection	Revision 1

NDIT S040-DH-0822	Cable Length Inputs for Combustible Loading Calculations Associated with Fire Zone 6.2 and 11.3	Revision 0
NDIT S040-DH-0822	Cable Length Inputs for Combustible Loading Calculations Associated with Fire Zone 6.2 and 11.3	Revision 1

Condition Reports

D2000-06142	Potential Exists That Safe Shutdown Surveillance No Longer Required	November 11, 2000
D2000-06314	MSA Air Packs Used For Fire Drill Not Set up Properly For Quick Use	November 20, 2000
D2000-06316	Fire Brigade Member Left Without Fire Gear During Fire Drill	November 20, 2000
D2001-00090	Failed Fire Drill Due to Poor Decision by The Safety Officer	November 20, 2000
D2001-01682	Lack of Fire Gear	March 26, 2001
00072943	Unannounced Fire Drill Critique	August 22, 2001
00073170	NOS/NEXUS Identified Enhancements For Safe Shutdown Timeline	August 17, 2001
00084203	4th Quarter Fire Drill Identify Improvements	November 27, 2001
00096739	Fire Protection SA Identifies Issues with Unit Dependence	February 26, 2002
00096750	Fire Protection SA Identified SSD Equipment Cart Location Concern	March 1, 2002
00096768	Fire Protection SA Identifies Cold Shutdown Repair Discrepancies	February 26, 2002
00097716	Fire Drill Identified Strengths And Weaknesses	March 1, 2002
00098819	Unannounced Fire Drill Shift c	March 14, 2002
00101015	Inconsistency Between the Safe Shutdown Report and SER	March 26, 2002
00102056	Protection of 250 VDC Control Circuits	April 2, 2002

Condition Reports Initiated As A Result of Inspection

00103348	SSD Emergency Light 400A Lamps Slightly Mis-aimed	April 11, 2002
00104855	Cubicle identified in DSSP 0100-CR is shown as spare on dwg	April 22, 2002
00105314	Misapplied Assumption in Combustible Load Calc DRE97-0105	April 25, 2002
00105045	Discrepancy in Fire Stop Surv procedure DFPS 4175-02	April 23, 2002
00105147	Emergency Light 229 not aimed per the surveillance criteria	April 24, 2002
00105410	NRC Concern over RB Temperature during App. R	April 25, 2002
00105417	NRC Concerns over DG Loading and Testing	April 25, 2002
00105419	AEER Gaseous Suppression (Halon) System Concerns	April 25, 2002
00105423	Provision of Diesel Fuel Oil Requirements for Appendix R	April 26, 2002
00105516	Calculations contain outdated references	April 26, 2002
00106996	Detector Spacing on Computer Room	May 6, 2002
00107050	Potential enhancement to Safe Shutdown Procedures	May 7, 2002
00107223	SSR Tables do not identify LPCI Valve as required	May 8, 2002

Correspondence

	Letter from J. A. Zwolinski to D. L. Farra dated July 1, 1985, Additional Information on Appendix R (Fire Protection)	July 1, 1985
	Letter to Mr. T. O'Brien, Dresden Station Diesel Generator Fuel Oil Calculations	June 25, 1991
	Letter - Response to NRC Staff Request for Additional Information (RAI) Regarding the Technical Specification Upgrade Program (TSUP)	May 15, 1995

	Letter - Issuance of Amendments Related to TSUP Section 3/4.9	September 18, 1995
PSLTR 00-0068	Request for Additional Information Regarding Individual Plant Examination of External Events	March 30, 2000
	Chemetron Letter to Mr. D. Galanis, Calculations and Various Support Documents for Dresden Station AEER Halon and Low Pressure CO_2 Fire Suppression Systems	May 20, 2002

Drawings

12E-2052	Cable Routing and Fire Stops Electrical and Computer Room Ground Floor	Revision AN
12E-2053	Cable Routing and Fire Stops Control Room Area	Revision W
12E-2056M	Electrical installation Fire Protection System TB Elev. 517'-6"	Revision R
12E-3440	Schematic Control Diagrams LPCI/Containment Cooling System MOVs	Revision W
12E-3441A	Schematic Control Diagrams LPCI/Containment Cooling System MOVs	Revision U
12E-6400B	Motor Operated Valves Limit Switch Development	Revision C
F-220	Fire Wrap Turbine Building Control Room Area	Revision C
F-363	Fire Suppression System TB Corridor	Revision P
F-382	Fire Suppression System Day Tanks	Revision C
F-384	Fire Suppression System Piping Plans Trackway Areas G&E	Revision N
F-430	Fire Suppression System Unit 2 Trackway Area	Revision B
F-431	Fire Protection System TB Ground Floor	Revision B
FLR-25062	Low Pressure Carbon Dioxide Fire Protection System, sheet 5	Revision C
FLR-25062	Low Pressure Carbon Dioxide Fire Protection System, sheet 6	Revision F
FLR 25062	Low Pressure Carbon Dioxide Fire Protection System, sheet 7	Revision D

FLR 25062-1	Halon 1301 Fire Suppression System, sheet 2	Revision A
FLR 25062-1	Halon - LP/CO_2 System, sheet 4	Revision A
FLR 25063-1	Halon 1301 Fire Extinguishing/Supersession System, sheet 1	Revision B
M-936	Diagram of East Turbine Room Ventilation System	Revision L

Fire Test Reports

NTSC Report No. 96-100.001	Dresden Fire Protection Program Document Package	Rev. 0
Southwest Research Institute 01-2912a	Qualification Fire Test of a Protective Envelope System	02/95

License Documents

TRM Section 3.3.e	Fire Detection Instrumentation	Rev. 0
TRM Section 3.7.i	Fire Water Supply System	Rev. 0
TRM Section 3.7.j	Water Suppression Systems	Rev. 0
TRM Section 3.7.k	Gaseous Suppression System	Rev. 0
TRM Section 3.7.l	Fire Hose Stations	Rev. 0
TRM Section 3.7.m	Safe Shutdown Lighting	Rev. 0
TRM Section 3.7.n	Fire Rated Assemblies	Rev. 0
DPR-19, Technical Specification	Section 3.12, Fire Protection Systems (Deleted)	Amendment 82

Procedures

CC-AA-10	Configuration Control Process Description	Revision 1
CC-AA-309	Control of Design Analysis	Revision 1
DFPS 4123-08	Fire Water System Flow Test	Revision 5
DHP 0120-07	Control of Ladders	Revision 3
DOP 3900-01	Service Water System Operation	Revision 7
Unit 2(3) DOS 0010-14	Safe Shutdown Equipment Inspection	Revision 19

DOS 1300-03	2/3A(B) Isolation Condenser Makeup Pump Quarterly Operability	Revision 8
Unit 2(3) DSSP 0010-01	Determining Safe Shutdown Paths for Extensive Plant Damage	Revision 8
Unit 2(3) DSSP-0100-B1	Hot Shutdown Procedure - Path B1	Revision 21
Unit 2(3) DSSP 0100-CR	Hot Shutdown Procedure - Control Room Evacuation	Revision 24
Unit 2(3) DSSP 0100-CR	Hot Shutdown Procedure - Control Room Evacuation	Revision 25
Unit 2(3) DSSP 0200-S	SDC Cold Shutdown Method	Revision 10
DSSP 0200-T2	Diesel Generator 2 (3) Local Manual Start	Revision 6
DSSP 0200-T3	Diesel Generator 2/3 Local Manual Start	Revision 8
DSSP 0200-T5	Repair of Dedicated Unit 3 D/G for Cold Shutdown with Loss of Remote Control Capability Due to Fire Damage	Revision 5
DTS 6600-02	Diesel Generator Fuel Consumption Test	Revision 5
NES-G-14	Calculations	Revision 1
RM-AA-102	Control of Documents	Revision 2
SA-AA-111	Heat Stress Control	Revision 0
Special Procedure 85-9-146	Radio Test for Appendix R Loss of Off-site Power Scenario	September 24, 1985
Special Procedure 88-4-27	Unit 2 Diesel Generator and Day Tank Room Low Pressure CO_2 Fire Suppression System Functional Operation and Concentration Test	Revision 0
Unit 2 Fire Pre-Plan U2TB-46	Unit 2 Turbine Building 517' Elevation Computer room/Auxiliary Electric Equipment Room, Fire Zone 6.2	Revision 5

Safety Evaluations

1997-03-204	AEER A/C Air Handling Unit, DCP 9700222	Rev. 0
1998-02-165	Amendment 11 of the Dresden Fire Protection Report (FPR) and Fire Protection Program Documentation Package (FFPDP)	Rev. 0

Self Assessments

	Dresden Station Triennial Fire Protection Assessment Report	September 14, 2001
	Dresden Station Fire Protection Self-Assessment Report	April 2, 2002
NO. Letter 12-02-13	Nuclear Oversight Readiness Letter for NRC Fire Protection Inspection - NRC Inspection Procedures 71111.05	April 9, 2002

System Descriptions

System Description Manual 286002	Gaseous Fire Protection Systems	Rev. 1
System Description 286N-01	Fire Protection Systems	Rev. 6

Work Orders

00420835	D3, D2, and D 2/3 TS Unit Diesel Generator Operation	Revision 73
00421905	D3, D2, and D 2/3 TS Unit Diesel Generator Operation	Revision 73
00424846	D3, D2, and D 2/3 TS Unit Diesel Generator Operation	Revision 73

TAB 24

May 5, 2005

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3
FIRE PROTECTION TRIENNIAL BASELINE INSPECTION
INSPECTION REPORT 05000237/2005002(DRS); 05000249/2005002(DRS)

Dear Mr. Crane:

On April 1, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Dresden Nuclear Power Station, Units 2 and 3. The enclosed report documents the inspection findings which were discussed on April 1, 2005, at the Dresden Station and during a telephone conference call on April 22, 2005, with Mr. D. Bost and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, one NRC-identified finding of very low safety significance, which involved a violation of NRC requirements, was identified. However, because the violation was of very low safety significance and because the issue was entered into the licensee's corrective action program, the NRC is treating this finding as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Dresden Nuclear Power facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Julio F. Lara, Chief
Engineering Branch 3
Division of Reactor Safety

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

Enclosure: Inspection Report 05000237/2005002(DRS); 05000249/2005002(DRS)
w/Attachment: Supplemental Information

cc w/encl:
Site Vice President - Dresden Nuclear Power Station
Dresden Nuclear Power Station Plant Manager
Regulatory Assurance Manager - Dresden
Chief Operating Officer
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional Operating Group
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing - Mid-West Regional Operating Group
Manager Licensing - Dresden and Quad Cities
Senior Counsel, Nuclear, Mid-West Regional Operating Group
Document Control Desk - Licensing
Assistant Attorney General
Illinois Department of Nuclear Safety
State Liaison Officer
Chairman, Illinois Commerce Commission

document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Julio F. Lara, Chief
Engineering Branch 3
Division of Reactor Safety

Docket Nos. 50-237; 50-249
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Enclosure: Inspection Report 05000237/2005002(DRS); 05000249/2005002(DRS)
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cc w/encl: Site Vice President - Dresden Nuclear Power Station
Dresden Nuclear Power Station Plant Manager
Regulatory Assurance Manager - Dresden
Chief Operating Officer
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional Operating Group
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing - Mid-West Regional Operating Group
Manager Licensing - Dresden and Quad Cities
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-237; 50-249
License Nos:	DPR-19; DPR-25
Report No:	05000237/2005002(DRS); 05000249/2005002(DRS)
Licensee:	Exelon Generation Company, LLC
Facility:	Dresden Nuclear Power Station, Units 2 and 3
Location:	6500 North Dresden Road Morris, IL 60450
Dates:	March 14 through April 1, 2005
Inspectors:	C. Chyu, Reactor Inspector G. Hausman, Senior Reactor Inspector, Lead A. Klett, Reactor Inspector R. Langstaff, Senior Reactor Inspector
Approved by:	J. Lara, Chief Engineering Branch 3 Division of Reactor Safety

Enclosure

SUMMARY OF FINDINGS

IR 05000237/2005002(DRS); 05000249/2005002(DRS); 03/14/2005 - 04/01/2005; Dresden Nuclear Power Station, Units 2 and 3; Fire Protection Triennial Baseline Inspection.

This report covers an announced triennial fire protection baseline inspection. The inspection was conducted by Region III inspectors. One Green finding associated with a Non-Cited Violation was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

No findings of significance were identified.

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance was identified by the inspectors for a violation of 10 CFR Part 50, Appendix B requirements. The licensee failed to specify the correct number of turns in a hot shutdown procedure for partially opening a valve relied upon to mitigate a fire. The incorrect number of turns specified in the procedure could have caused a significant delay in performance of safe shutdown actions in the event of a fire. Once identified, the licensee entered the finding into their corrective action program to revise the affected procedures.

  This finding was more than minor because the procedural error could have caused a significant delay in the performance of safe shutdown actions in the event of a fire. The issue was of very low safety significance because the licensee's analysis showed that sufficient margin remained for the performance of the safe shutdown actions. The finding was a Non-Cited Violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, which required procedures affecting quality to be of a type appropriate to the circumstances. (Section 1R05.5b)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 2 operated at or near full power at the start of the inspection. On March 24, 2005, a Unit 2 reactor scram occurred. Unit 2 was returned to full power on March 27, 2005.

Unit 3 operated at or near full power throughout the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events and Mitigating Systems

1R05 Fire Protection (71111.05)

The purpose of this inspection was to review the Dresden Nuclear Power Station's (DNPSs) Fire Protection Program (FPP) for selected risk-significant fire areas. Emphasis was placed on determining that the post-fire safe shutdown capability and the fire protection features were maintained free of fire damage to ensure that at least one post-fire safe shutdown success path was available. The inspection was performed in accordance with the Nuclear Regulatory Commission's (NRCs) regulatory oversight process using a risk-informed approach for selecting the fire areas and attributes to be inspected. The inspectors used the DNPSs Individual Plant Examination of External Events (IPEEE) to choose several risk-significant areas for detailed inspection and review. The fire zones chosen for review during this inspection were:

Selected Fire Areas and Zones

Fire Area	Fire Zones	Description
RB2-II	1.1.2.3	Unit 2 Second Floor Reactor Building
TB-III	8.2.5.E	Unit 3 West Corridor and Trackway
TB-III	8.2.6.E	Unit 3 Mezzanine Floor

For each of these fire zones, the inspection focused on the fire protection features, the systems and equipment necessary to achieve and maintain safe shutdown conditions, determination of licensee commitments, and changes to the FPP.

.1 Systems Required to Achieve and Maintain Post-Fire Safe Shutdown

Title 10 of the Code of Federal Regulations (CFR), Part 50, Appendix R, Section III.G.1, required the licensee to provide fire protection features that were capable of limiting fire damage to structures, systems, and components (SSCs) important to safe shutdown. The SSCs that were necessary to achieve and maintain post-fire safe shutdown were required to be protected by fire protection features that were capable of limiting fire damage to the SSCs so that:

- One train of systems necessary to achieve and maintain hot shutdown conditions from either the control room or emergency control station(s) was free of fire damage; and

- Systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station(s) can be repaired within 72-hours.

Specific design features for ensuring this capability were specified by 10 CFR Part 50, Appendix R, Section III.G.2.

a. Inspection Scope

The inspectors reviewed the plant systems required to achieve and maintain post-fire safe shutdown to determine if the licensee had properly identified the components and systems necessary to achieve and maintain safe shutdown conditions for each fire area selected for review in accordance with the criteria discussed above. Specifically, the review was performed to determine the adequacy of the systems selected for reactivity control, reactor coolant makeup, reactor heat removal, process monitoring, and support system functions. This review included the fire protection safe shutdown analysis.

The inspectors also reviewed the operators' ability to perform the necessary manual actions for achieving safe shutdown by reviewing procedures, the accessibility of safe shutdown equipment, and the available time for performing the actions.

The inspectors reviewed the DNPSs Updated Safety Analysis Report and the licensee's engineering and/or licensing justifications (e.g., NRC guidance documents, license amendments, technical specifications, safety evaluation reports, exemptions, and deviations) to determine the licensing basis.

b. Findings

No findings of significance were identified.

.2 Fire Protection of Safe Shutdown Capability

Title 10 CFR Part 50, Appendix R, Section III.G.2, required separation of cables and equipment and associated circuits of redundant trains by a fire barrier having a 3-hour rating. Title 10 CFR Part 50, Appendix R, Section III.G.3, required that, if the guidelines cannot be met, then alternative or dedicated shutdown capability and its associated circuits, independent of cables, systems or components in the area, room, or zone under consideration should be provided.

a. Inspection Scope

For each of the selected fire zones, the inspectors reviewed the licensee's Safe Shutdown Analysis (SSA) to ensure that at least one post-fire safe shutdown success path was available in the event of a fire in accordance with the criteria discussed above. This included a review of manual actions required to achieve and maintain hot shutdown conditions and to make the necessary repairs to reach cold shutdown within 72-hours. The inspectors also reviewed procedures to determine whether or not adequate direction was provided to operators to perform these manual actions. Factors such as timing, access to the equipment, and the availability of procedures, were considered in the review.

The inspectors also evaluated the adequacy of fire suppression and detection systems, fire area barriers, penetration seals, and fire doors to ensure that at least one train of safe shutdown equipment was free of fire damage. To accomplish this, the inspectors observed the material condition and configuration of the installed fire detection and suppression systems, fire barriers, construction details, and supporting fire tests for the installed fire barriers. In addition, the inspectors reviewed licensee documentation, such as deviations, detector placement drawings, fire hose station drawings, carbon dioxide pre-operational test reports, smoke removal plans, Fire Hazard Analysis (FHA) reports, SSA, and National Fire Protection Association (NFPA) codes to verify that the fire barrier installations met license commitments.

b. Findings

No findings of significance were identified.

.3 Post-Fire Safe Shutdown Circuit Analysis

Title 10 CFR Part 50, Appendix R, Section III.G.1, required that SSCs important to safe shutdown be provided with fire protection features capable of limiting fire damage to ensure that one train of systems necessary to achieve and maintain hot shutdown conditions remained free of fire damage. Options for providing this level of fire protection were delineated in 10 CFR Part 50, Appendix R, Section III.G.2. Where the protection of systems whose function was required for hot shutdown did not satisfy 10 CFR Part 50, Appendix R, Section III.G.2, an alternative or dedicated shutdown capability and its associated circuits, were required to be provided that was independent of the cables, systems, and components in the area. For such areas, 10 CFR Part 50, Appendix R, Section III.L.3, specifically required the alternative or dedicated shutdown capability to be physically and electrically independent of the specific fire areas and capable of accommodating post-fire conditions where offsite power was available and where offsite power was not available for 72 hours.

a. Inspection Scope

The inspectors performed a review of the licensee's SSA and Safe Shutdown Equipment List (SSEL) to determine whether the licensee had appropriately identified and analyzed the safety related and non-safety related cables associated with safe shutdown equipment located in the selected plant fire zones in accordance with the criteria discussed above. The inspectors' review included the assessment of the licensee's electrical systems and electrical circuit analyses.

The inspectors evaluated a sample of safety and non-safety related cables for equipment in the selected fire zones to determine if the design requirements of Section III.G of Appendix R to 10 CFR Part 50 were being met. This included determining that hot shorts, open circuits, or shorts to ground would not prevent implementation of safe shutdown.

b. Findings

Introduction: The inspectors identified that the licensee evaluated their post-fire safe shutdown circuit analysis using a method that was not consistent with the methodology described in the NRC Regulatory Issue Summary (RIS) 2004-003, Revision 1, "Risk-Informed Approach for Post-Fire Safe-Shutdown Circuit Inspections," issued on December 29, 2004. The licensee's position was that the RIS guidance was outside DNPSs licensing basis.

Description: During the inspectors' review of the licensee's FPP, specifically the review of Issue Report (IR) 00311499, "Potential for Multiple Spurious Actuations During Fire," dated March 11, 2005, the licensee stated that the RIS guidance exceeded the Dresden licensing basis, which only required DNPSs consideration of any and all spurious signals taken one at a time. The licensee stated that the RIS 2004-003, Revision 1, guidance and/or methodology was not within the DNPSs licensing basis.

Based on the licensee's position, as stated in the IR, the inspectors requested the licensee to provide a basis supporting their position with respect to the RIS. On March 24, 2005, the licensee provided a position paper and supporting documentation. The position paper and supporting documentation did not specifically state that the NRC approved DNPSs methodology for analyzing fire induced spurious operations based on a single spurious operation.

Further discussions between the licensee and the NRC on April 13, 2005, did not provide new, additional information. As a result, the NRC concluded that a thorough review of DNPSs licensing basis was necessary and additional inspection effort was warranted to evaluate the licensee's FPP. Therefore, pending review and completion of additional inspection activities concerning the DNPSs FPP, this issue is an Unresolved Item (URI) (URI 05000237/2005002-01(DRS); 05000249/2005002-01(DRS)).

.4 Alternative Shutdown Capability

Title 10, Part 50, Appendix R, Section III.G.1, required the licensee to provide fire protection features that were capable of limiting fire damage so that one train of systems necessary to achieve and maintain hot shutdown conditions remained free of fire damage. Specific design features for ensuring this capability were provided in 10 CFR Part 50, Appendix R, Section III.G.2. Where compliance with the separation criteria of 10 CFR Part 50, Appendix R, Section III.G.2, could not be met, an alternative or dedicated shutdown capability be provided that was independent of the specific fire area under consideration. Additionally, alternative or dedicated shutdown capability must be able to achieve and maintain hot standby conditions and achieve cold shutdown conditions within 72-hours and maintain cold shutdown conditions thereafter. During the post-fire safe shutdown, the reactor coolant process variables must remain within those predicted for a loss of normal alternating current power, and the fission product boundary integrity must not be affected (i.e., no fuel clad damage, rupture of any primary coolant boundary, or rupture of the containment boundary).

a. Inspection Scope

The inspectors reviewed the licensee's systems required to achieve safe shutdown to determine if the licensee had properly identified the components and systems necessary to achieve and maintain safe shutdown conditions in accordance with the criteria discussed above. The inspectors also focused on the adequacy of the systems to perform reactor pressure control, reactivity control, reactor coolant makeup, decay heat removal, process monitoring, and support system functions.

b. Findings

No findings of significance were identified.

.5 Operational Implementation of Alternate Shutdown Capability

The DNPSs FPP described the means by which safe shutdown could be achieved to meet the requirements of 10 CFR Part 50, Appendix R, Sections III.G.3 and III.L. The DNPSs safe shutdown analysis identified the minimum number of components and plant systems necessary for achieving Appendix R safe shutdown performance goals.

a. Inspection Scope

The inspectors performed a review of the licensee's operating procedures, which augmented the post-fire safe shutdown procedures to determine if the licensee complied with the criteria discussed above. The review focused on ensuring that all required functions for post-fire safe shutdown and the corresponding equipment necessary to perform those functions were included in the procedures. The review also looked at operator training, as well as consistency between the operations shutdown procedures and any associated administrative controls.

b. Findings

Introduction: The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, having very low safety significance (Green) for failing to specify the correct number of turns in a hot shutdown procedure for partially opening a valve relied upon to mitigate a fire. The incorrect number of turns specified in the procedure could have caused a significant delay in performance of safe shutdown actions in the event of a fire.

Description: Safe shutdown actions for a significant fire in Fire Area RB2-1 (Unit 2 Reactor Building) were outlined in DSSP 0100-B1, "Hot Shutdown Procedure - Path B1." The procedure's Attachment E, "U2 EA [equipment attendant] Actions," specified local manual actions that initiated cooling using the isolation condenser. Step 1.c of DSSP 0100-B1 (Revision 26), Attachment E, directed operators to manually open valve MO 2-1301-2 by engaging the handwheel and cranking the valve to its backseat or until completing 553 turns. Valve MO 2-1301-2 was normally an open valve. However, the licensee determined that, if the valve had spuriously closed in the event of a fire, the valve would have to be manually opened at least halfway to provide adequate steam flow to the isolation condenser. When the inspectors questioned the licensee on how long it would take to perform this procedure step, the licensee's engineering personnel determined that the valve only required 190 turns to open the valve halfway for an estimated time of 10 minutes. However, given the procedural guidance to open the valve by cranking it to its backseat or until completing 553 turns, an operator would have fully opened the valve. Licensee engineering personnel estimated that it would take 18.5 minutes to fully open the valve manually. Licensee operations personnel estimated the amount of time it would take to complete the actions (including fully opening valve MO 2-1301-2) to initiate isolation condenser cooling specified by DSSP 0100-B1, Attachment E, to be 31 minutes. The estimates were based on a combination of walkdowns of portions of the procedure and judgement. The walkdowns did account for taking an alternate route so as to avoid entering the affected fire area. The inspectors noted that the calculated evaluation of fire scenarios (i.e., Calculation GE-NE-A22-00103-56-01-D, "Dresden and Quad Cities Extended Power Uprate Evaluation, Task T0611: Appendix R Fire Protection (Dresden Station)," Revision 1) concluded that, under worst case conditions, operations personnel would only have 32 minutes to initiate isolation condenser cooling. The inspectors concluded that the procedure error could result in a significant delay in performance of safe shutdown actions in the event of a fire. The delay was significant because it could result in a significant reduction of margin from 9.5 minutes to 1 minute for performing operator actions.

Analysis: The inspectors determined that failing to specify the correct number of turns to manually open valve MO 2-1301-2 halfway was a performance deficiency warranting a significance determination evaluation. The inspectors concluded that the finding was greater than minor in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on June 20, 2003. The finding involved the attribute of protection against external factors (fire) in that the procedural error resulted in a significant delay for performing safe shutdown manual actions in the event of a fire.

The inspectors completed a significance determination of this finding using IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated December 1, 2004, and IMC 0609, Appendix F, "Fire Protection Significance Determination Process," dated February 28, 2005. Based on review of IMC 0609, Appendix F, the inspectors concluded that the finding affected the post-fire plant response procedures element of the post-fire safe-shutdown finding category. However, since the licensee's analysis showed that sufficient margin remained for the performance of the safe shutdown actions, the inspectors determined that the finding was of very low safety significance (Green).

Enforcement: The licensee's Quality Assurance Program (QAP) is the method for complying with the provisions of 10 CFR Part 50, Appendix B requirements. The QAP is defined in NO-AA-10, "Quality Assurance Topical Report [QATR]," Revision 72, and its implementing procedures. The licensee's FPP and supporting operational activities are defined in the QATR's Appendix A and F as meeting augmented quality requirements. The QATR stated that the provisions of 10 CFR Part 50, Appendix B requirements shall be used for augmented quality requirements.

Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances. Procedure DSSP 0100-B1 was a procedure for activities affecting quality in that the procedure directed operators to manipulate safety-related equipment such as valve MO 2-1301-2. Contrary to the above, as of April 1, 2005, DSSP 0100-B1, Revision 26, was not a procedure of a type appropriate to the circumstances in that Step 1.c of DSSP 0100-B1, Attachment E, specified the incorrect number of turns for manually opening valve MO 2-1301-2 halfway. The incorrect number of turns specified by the procedure had the potential to cause an operator to fully open valve MO 2-1301-2, thereby, significantly delaying performance of safe shutdown actions used to initiate isolation condenser cooling in the event of a fire. The licensee's engineering staff entered this finding into the licensee's corrective action program as Issue Report (IR) 00315437 on March 21, 2005, to revise the affected procedures. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000237/2005002-02(DRS); 05000249/2005002-02(DRS)).

.6 Communications

Title 10 CFR Part 50, Appendix R, Section III.H, required that a portable communications system be provided for use by the fire brigade and other operations personnel required to achieve safe plant shutdown. This system should not interfere with the communications capabilities of other plant personnel. Fixed repeaters installed to permit use of portable radio communication units should be protected from exposure to fire damage.

a. Inspection Scope

The inspectors reviewed the adequacy of the communication systems to support plant personnel in the performance of alternative safe shutdown functions and fire brigade duties to determine compliance. The inspectors conducted a review to determine that adequate communications were available to support safe shutdown implementation.

b. Findings

No findings of significance were identified.

.7 Emergency Lighting

Title 10 CFR Part 50, Appendix R, Section III.J., required that fixed self-contained lighting consisting of fluorescent or sealed-beam units with individual eight-hour minimum battery power supplies should be provided in areas that must be manned for safe shutdown and for access and egress routes to and from all fire zones.

a. Inspection Scope

The inspectors performed a walkdown of the fire zones and the access/egress routes to determine that adequate emergency lighting existed in accordance with the criteria discussed above.

b. Findings

No findings of significance were identified.

.8 Cold Shutdown Repairs

Title 10 CFR Part 50, Appendix R, Section III.L.5, required that equipment and systems comprising the means to achieve and maintain cold shutdown conditions should not be damaged by fire; or the fire damage to such equipment and systems should be limited so that the systems can be made operable and cold shutdown achieved within 72 hours. Materials for such repairs shall be readily available onsite, and procedures shall be in effect to implement such repairs.

a. Inspection Scope

The inspectors reviewed the licensee's procedures to determine if any repairs were required to achieve cold shutdown. The inspectors determined that the licensee did require repair of some equipment to reach cold shutdown based on the safe shutdown methods used. The inspectors reviewed the procedures for adequacy.

b. Findings

No findings of significance were identified.

.9 Fire Barriers and Fire Zone/Room Penetration Seals

Title 10 CFR Part 50, Appendix R, Section III.M, required that penetration seal designs be qualified by tests that are comparable to tests used to rate fire barriers.

a. Inspection Scope

The inspectors performed visual inspections of selected three-hour rated barriers to ensure that the barrier installations were consistent with the criteria discussed above. In addition, the inspectors reviewed the fire loading for selected areas to ensure that existing barriers would not be challenged by a potential fire.

b. Findings

No findings of significance were identified.

.10 Fire Protection Systems, Features and Equipment

a. Inspection Scope

The inspectors reviewed the material condition, operations lineup, operational effectiveness, and design of fire detection systems, fire suppression systems, manual fire fighting equipment, fire brigade capability, and passive fire protection features. The inspectors reviewed deviations, detector placement drawings, fire hose station drawings, and fire hazard analysis reports to ensure that selected fire detection systems, sprinkler systems, portable fire extinguishers, and hose stations were installed in accordance with their design, and that their design was adequate given the current equipment layout and plant configuration.

b. Findings

No findings of significance were identified.

.11 Compensatory Measures

a. Inspection Scope

The inspectors conducted a review to determine that adequate compensatory measures were put in place by the licensee for out-of-service, degraded or inoperable fire protection and post-fire safe shutdown equipment, systems, or features. The inspectors also reviewed the adequacy of short term compensatory measures to compensate for a degraded function or feature until appropriate corrective actions were taken.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA2 Identification and Resolution of Problems (71152)

a. Inspection Scope

The inspectors reviewed the corrective action program procedures and samples of corrective action documents to assess whether or not the licensee was identifying issues related to fire protection at an appropriate threshold and entering them in the corrective action program. The inspectors reviewed selected samples of condition reports, work orders, design packages, and fire protection system non-conformance documents.

b. Findings

No findings of significance were identified.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. Bost and other members of licensee management at the conclusion of the inspection on April 1, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

A telephone conference call was made on April 22, 2005, with other members of licensee management to identify the URI discussed in Section 1R05.3b.

.2 Interim Exit Meetings

No interim exits were conducted.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

<u>Licensee</u>
C. Barajas, Shift Operations Superintendent
J. Bashor, Work Management Director
P. Bembnister, Fire Protection System Engineer
G. Bockholdt, Maintenance Director
D. Bost, Site Vice President
M. Dillon, Fire Protection Contractor
R. Gadbois, Operations Director
D. Galanis, Design Engineering Manager
J. Griffin, NRC Coordinator
D. Gullott, Corporate Licensing
M. Kanavos, Site Engineering Director
A. Khanifar, Nuclear Oversight Manager
M. Kluge, Design Engineering
D. Knox, Design Engineering
A. Mauro, Operation/Fire Marshall
J. Ondish, Design Engineering
C. Pragman, Corporate Fire Protection
R. Ruffin, Operations
B. Rybak, Lead Licensing Engineer
P. Salas, Regulatory Assurance Manager
P. Simpson, Corporate Licensing Manager
J. Sipek, Engineering Programs Manager
C. Symonds, Training Director
D. Wozniak, Plant Manager

<u>Nuclear Regulatory Commission</u>
J. Lara, Engineering Branch 3 Chief
C. Phillips, Senior Resident Inspector
D. Smith, Senior Resident Inspector

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000237/2005002-01(DRS); 05000249/2005002-01(DRS)	URI	Post-Fire Safe-Shutdown Circuit Analysis Not Consistent with RIS 2004-003 (Section 1R05.3b)
05000237/2005002-02(DRS); 05000249/2005002-02(DRS)	NCV	Safe Shutdown Procedure Failed to Specify Correct Number of Turns for Opening Valve (Section 1R05.5b)

Closed

05000237/2005002-02(DRS); 05000249/2005002-02(DRS)	NCV	Safe Shutdown Procedure Failed to Specify Correct Number of Turns for Opening Valve (Section 1R05.5b)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

CALCULATIONS

Number	Description or Title	Date or Revision
DRE 96-0149	Breaker Settings for Bus 28 and 29	3
DRE 97-0061	Dresden Station Fire Main Equivalent Lengths	3
DRE 97-0105	Fire Loading Calculation Sheet	5

CORRECTIVE ACTION PROGRAM DOCUMENTS ISSUED DURING INSPECTION

Number	Description or Title	Date or Revision
00311476	Controlled Permits Lost	March 11, 2005
00311485	Discrepancies Identified in DSSP CSD Procedures	March 11, 2005
00311486	Potential Enhancement Identified for Fire Pre-Plans	March 11, 2005
00311493	ECCS Keep Fill System Not Included App R Analysis	March 11, 2005
00311499	Potential for Multiple Spurious Actuations During Fire	March 11, 2005
00313561	Discrepancies in FP SSD Report Table 7.3-2	March 16, 2005
00313562	Sprinkler Head Interference Evaluation	March 16, 2005
00313940	Tarp Not Removed per DMP 5700-05 Requirements	March 17, 2005
00314491	DSSP Ladder Reference Basis Unclear	March 18, 2005
00315437	DSSP Identifies Incorrect # of Turns to Open Valve	March 21, 2005
00318259	Incorrect Equipment Designation on Drawing 12E-2051	March 29, 2005
00318261	Dwg 12E-3901P Shows Unnecessary Information	March 29, 2005
00318887	Evaluate Iso Cond Floor Fire Extinguisher Placement	March 30, 2005
00319654	NRC Questions Hourly Fire Watch Practices	March 31, 2005

CORRECTIVE ACTION PROGRAM DOCUMENTS (CRs) ISSUED PRIOR TO INSPECTION

Number	Description or Title	Date or Revision
00201611	NRC Concerns with FP System Impairment Control	February 12, 2004
00280050	Fire Hose Reel F-126 Found Pressurized	December 9, 2004
00283306	Smoke Detector Did Not Respond to Testing	December 20, 2004
00285801	Can Not Find Documentation for Fire Barrier Pen	December 27, 2004
00286640	Possible Fire System Restriction	January 9, 2005
00288055	2/3-4101 Battery Cells 8, 14, 16, and 31 Low Voltage	January 6, 2005
00290049	3 WO Drums Found with No TC Permit	January 14, 2005
00292090	CO_2 Extinguishers in Place of Halon Extinguishers	January 24, 2005
00292533	AEER Halon Main Discharge Cylinder - Low Pressure	January 24, 2005
00298166	Main FD Breakers Not Properly Sealed	February 7, 2005
00299076	Emergency Light 343 Lamp Head Mis-Positioned	February 9, 2005
00300164	Combustible Loading Calculations Discrepancies	February 14, 2005

CORRECTIVE ACTION PROGRAM DOCUMENTS (CRs) ISSUED PRIOR TO INSPECTION

Number	Description or Title	Date or Revision
00301557	EPU App R Analysis Did Not Include GESIL 636 Effect	February 17, 2005
00302038	FPR Documentation Issues	February 18, 2005
00309314	Bus 31 Main FD Bkr Cooling Fan Bkr Fire	March 7, 2005

DRAWINGS

Number	Description or Title	Date or Revision
F-1	Legend and Description	D
F-2-1	Detection and Suppression RX Bldg El 476'-6"	H
F-2-2	HSD-Iso Cond Method RX Bldg El 476'-6"	C
F-2-4	CSD SDC RX Bldg El 476'-6"	B
F-2-5	CSD Div II LPCI RX Bldg El 476'-6"	B
F-3-1	Detection and Suppression RX Bldg El 517'-6"	H
F-3-2	HSD-Iso Cond Method RX Bldg El 517'-6"	D
F-3-4	CSD SDC RX Bldg El 517'-6"	C
F-3-5	CSD Div II LPCI RX Bldg El 517'-6"	C
F-4-1	Detection and Suppression RX Bldg El 545'-6"	F
F-4-2	HSD-Iso Cond Method RX Bldg El 545'-6"	B
F-4-4	CSD SDC RX Bldg El 545'-6"	A
F-4-5	CSD Div II LPCI RX Bldg El 545'-6"	A
F-5-1	Detection and Suppression RX Bldg El 570'-0"	H
F-5-2	HSD-Iso Cond Method RX Bldg El 570'-0"	B
F-5-4	CSD SDC RX Bldg El 570'-0"	B
F-5-5	CSD Div II LPCI RX Bldg El 570'-0"	B
F-6-1	Detection and Suppression RX Bldg El 589'-0"	F
B-204	RX Bldg Framing Plan El 570'-0" South Area	AA
B-205	RX Bldg Framing Plan El 570'-0" North Area	AB
F-6-2	HSD-Iso Cond Method RX Bldg El 589'-0"	B
F-7-1	Detection and Suppression RX Bldg El 613'-0"	C
F-8-1, Sht 1	Detection and Suppression CR and Misc Turb Bldg Floor	L
F-8-1, Sht 2	Detection and Suppression CR Floor	A
F-8-2, Sht 1	HSD-Iso Cond Method CR and Misc	C
F-8-2, Sht 2	HSD-Iso Cond Method CR and Misc	B
F-8-4, Sht 1	CSD SDC CR El 534'-0" and Main El 561'-6"	A
F-8-4, Sht 2	CSD SDC AEER El 517'-6" and Battery Rm El 549'-0"	B
F-8-5, Sht 1	CSD Div II LPCI CR El 534'-0" and Main El 561'-6"	A
F-8-5, Sht 2	CSD Div II LPCI AEER El 517'-6" and Batt Rm El 549'-0"	B
F-9-1	Detection and Suppression Turb Bldg Basement Floor	C
F-9-2	HSD-Iso Cond Method Turb Bldg Basement Floor	A
F-9-4	CSD SDC Turb Bldg Basement Floor	A
F-9-5	CSD Div II LPCI Turb Bldg Basement Floor	A
F-10-1	Detection and Suppression Turb Bldg Grd Floor	F

DRAWINGS

Number	Description or Title	Date or Revision
F-10-2	HSD-Iso Cond Method Turb Bldg Grd Floor	C
F-10-4	CSD SDC Turb Bldg Grd Floor	B
F-11-1	Detection and Suppression Turb Bldg Grd Floor	G
F-11-2	HSD-Iso Cond Method Turb Bldg Grd Floor	C
F-11-4	CSD SDC Turb Bldg Grd Floor	B
F-11-5	CSD Div II LPCI Turb Bldg Grd Floor	B
F-13-1	Detection and Suppression Turb Bldg Mezz Floor	F
F-13-2	HSD-Iso Cond Method Turb Bldg Mezz Floor	B
F-13-4	CSD SDC Turb Bldg Mezz Floor	B
F-13-5	CSD Div II LPCI Turb Bldg Mezz Floor	B
F-14-1	Detection and Suppression Turb Bldg Mezz Floor	F
F-14-2	HSD-Iso Cond Method Turb Bldg Mezz Floor	B
F-14-4	CSD SDC Turb Bldg Mezz Floor	B
F-14-5	CSD Div II LPCI Turb Bldg Mezz Floor	B
F-18-2	HSD-Iso Cond Method Crib House	A
F-18-4	CSD SDC Crib House	A
F-202-6	Lighting Emergency Battery Units RX Bldg El 545'-6"	E
F-390	FS System RX FD Pumps/Turb Bearing Lift Pumps	G
M-11	P and ID Index	V
M-11, Sheet 2	Piping and Instr Symbols	K
M-21	Diagram of Turb Bldg Cooling Water Piping	MG
M-22	Diagram of Pen Piping	DK
M-26, Sheet 2	Diagram of Nuclear Boiler and RX Recirculation Piping	KA
M-28	Diagram of Iso Cond Piping	LK
M-29, Sheet 1	Diagram of LPCI Piping	CE
M-29, Sheet 2	Diagram of LPCI Piping	AY
M-32	Diagram of SD RX Cooling Piping	BA
M-34, Sheet 1	Diagram of CRD Hydraulic Piping	AF
M-35, Sheet 1	Diagram of Demineralized Water System Piping	DN
M-41, Sheet 1	Diagram of Turb and Diesel Oil Piping	MT
M-41, Sheet 2	Diagram of Turb and Diesel Oil Piping	AA
M-51	Diagram of High Pressure Coolant Injection Piping	CH
M-354, Sheet 2	Diagram of Turb Bldg Cooling Water Piping	BB
M-355	Diagram of Pen Piping	RM
M-357, Sheet 2	Diagram of Nuclear Boiler and RX Recirculating Piping	BK
M-359	Diagram of Iso Cond Piping	BF
M-360, Sheet 1	Diagram of LPCI System	VK
M-360, Sheet 2	Diagram of LPCI System	AU
M-363	Diagram of SD RX Cooling Piping	BA
M-374	Diagram of High Pressure Coolant Injection Piping	CL
M-365, Sheet 1	Diagram of CRD Hydraulic Piping	AC
M-518, Sheet 2	D/G Fuel Oil System	D
M-974	Diagram of DG Room Ventilation	H
M-1297	Diagram of DG and Battery Room Bldg HVAC	C

DRAWINGS

Number	Description or Title	Date or Revision
M-4203	Flow Diagram Iso Cond Make Up System	D
12E-2049	C/R and F/Ss Turb Bldg, RX Bldg and Crib House	V
12E-2050	C/R and F/Ss Turb, RX Bldg Grd Floor	AP
12E-2051	C/R and F/Ss Turb and RX Bldg Mezz Floor	AL
12E-2051A	C/R and F/Ss Mezz Turb and RX Bldg	D
12E-2052	C/R and F/Ss Electrical and Computer Rm El 517'-6"	AN
12E-2053	C/R and F/Ss CR Area El 534'-0" and 549'-0"	W
12E-2054	Front Elevation and Mounting Detail 4160V/480V SWGR	CN
12E-2079F	FP System RX Bldg El 545'-6" North Area	E
12E-2080H	FP System RX Bldg El 545'-6" South Area	E
12E-2301, Sheet 1	Single Line Diagram	AL
12E-2301, Sheet 2	Single Line Diagram	AG
12E-2301, Sheet 3	Single Line Diagram	AS
12E-2301, Sheet 4	Single Line Diagram	B
12E-2302A	Station K/D 4160V and 480V SWGRs 480V MCCs	V
12E-2303, Sheet 2	K/D 4160V SWGRs 23 and 24	V
12E-2303, Sheet 3	K/D 4160V SWGRs 23 and 24	B
12E-2304	K/D 4160V SWGRs 23-1 and 24-1	V
12E-2321	K/D 250Vdc MCCs	AM
12E-2322, Sheet 1	K/D Turb Bldg 125Vdc Main Bus 2A-1 Dist Panel	AN
12E-2322, Sheet 2	K/D Turb Bldg 125Vdc Buses 2A-1 and 2A-2 Dist Panels	AL
12E-2322, Sheet 3	K/D RX Bldg 125Vdc Main Bus 2 Dist Panel	AE
12E-2322A	K/D Turb Bldg 125Vdc Reserve Bus Dist Panel	N
12E-2322B	Overall K/D 125Vdc Dist Centers	K
12E-2328	Single Line Diagram Emergency Power System	M
12E-2330	Synchronizing Diagram	U
12E-2342	S/D 4160V Bus 23 Main and Reserve FD G.C.B.'s	AD
12E-2342A	S/D 4160V SWGR Bus 23 Alternate FD	A
12E-2344, Sheet 1	S/D Control 4160V Bus 23-1 FD Bkrs	W
12E-2344, Sheet 2	S/D 4160V Bus 23-1 Main FD Bkr	Y
12E-2345, Sheet 1	S/D 4160V Bus 23-1 4kV SWGR Bus 40 FD Bkr	AW
12E-2345, Sheet 2	S/D 4160V Bus 23-1 4kV SWGR Bus 40 FD Bkr	AS
12E-2345, Sheet 3	S/D 4160V Bus 23-1 Undervoltage Relay	AL
12E-2345, Sheet 4	S/D 4160V Bus 23-1 33-1 Tie Bkr	D
12E-2351, Sheet 3	S/D 4160V DG 2/3 Auxiliaries and Start Relays	AF
12E-2391	S/D SW Pumps and Strainers	L
12E-2416	S/D CRD Hydraulic Pumps and Valves	W
12E-2416A	S/D CRD Hydraulic System MOVs	B
12E-2484	S/D Iso Cond System MOVs	S
12E-2502, Sheet 1	S/D PCIS Switch Development, Reset Circuit, TIP Isolation, Recirculation Loop Interlock, Sheet 2	AM

DRAWINGS

Number	Description or Title	Date or Revision
12E-2502, Sheet 2	S/D PCIS Switch Development, Reset Circuit, TIP Isolation, Recirculation Loop Interlock	AF
12E-2502A	S/D PCIS Reset Circuit	H
12E-2506, Sheet 1	S/D PCIS Iso Cond Control Logic	AP
12E-2506, Sheet 2	S/D PCIS Iso Cond Control Logic	AN
12E-2506, Sheet 3	S/D PCIS Iso Cond Control Logic	AM
12E-2507	S/D PCIS Iso Cond - Outboard MOV 1301-3 Control	AL
12E-2507A	S/D PCIS MOV 1301-2 Control	T
12E-2507B	S/D Iso Cond RX Inlet Vlv 2-1301-1 and 2-1301-4	N
12E-2575BF	S/D CR Annunciator Panel 902-7 Part 1 of 5	C
12E-2575BM	S/D CR Annunciator Panel 902-8 Part 2 of 6	K
12E-2645C	Front View and W/D Synch Relay Cabinet DG 2 and 2/3	C
12E-2647A	Front Elevation and W/D DG 2/3 Neutral Grd Comp	C
12E-2649A	W/D Standby DG 2/3 Relay and Meter Panel 2223-33	AH
12E-2649D	Annunciator B Schematic, Wiring, and Window Display	R
12E-2653A	W/D 4160V SWGR Bus 23 Cubicle 1, 2, 3, 4, 5, and 6	AG
12E-2653B	W/D 4160V SWGR Bus 23 Cubicle 7, 8, 9, 10, 11, 12, and 13	AC
12E-2655B	W/D 4160V SWGR Bus 23-1 Cubicle 9, 10, 11, 12, and 13	AV
12E-2656H	Internal Schematic and Device Location Diagram 4160V SWGR Bus 24-1 Cubicle 13	K
12E-2664E	Wiring and S/D 480V Turb Bldg MCC 25-2 Part 5	M
12E-2674D	Wiring and S/D 480V RX Bldg MCC 28-1 (2-7828-1)	AB
12E-2674E	Wiring and S/D 480V RX Bldg MCC 28-1 (2-7828-1)	AI
12E-2676B	Wiring and S/D 480V Turb Bldg MCC 28-3 Part 2	AD
12E-2679C	Wiring and S/D 480V RX Bldg MCC 29-3 Part 3	O
12E-2684A	Wiring and S/D RX Bldg 250Vdc MCC 2A Part 1	O
12E-2684C	W/D RX Bldg 250Vdc MCC 2A Part 3	AC
12E-2684G	W/D Internals - RX Bldg 250Vdc MCC 2A and 2B	U
12E-2695	W/D MCB Panel 902-3 MSIP Iso Cond	DZ
12E-2696	W/D MCB Panel 902-3 MSIP Iso Cond	BT
12E-2697	W/D MCB Panel 902-3 CS - LPCI/CONT	CJ
12E-2698	W/D MCB Panel 902-3 CS - LPCI/CONT	AQ
12E-2704	W/D MCB Panel 902-3	J
12E-2732	W/D MCB Panel 902-7, Part 5 Term Blocks E, F, G, and H	T
12E-2736	W/D MCB Panel 902-8 Part 1 - Front Face	AN
12E-2741	W/D MCB Panel 902-8 Term Blocks G thru K Part 6	AV
12E-2752B	W/D Panel 902-20 Part 2	N
12E-2757D	W/D AEER Panel 902-32	AZ
12E-2769A	W/D Instr Rack 2202-5 Section A RX Instr and Prot	AC
12E-2770A	W/D RX Instr and Prot Local Rack 2202-6 Section A	AF

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Number	Description or Title	Date or Revision
12E-2788	W/D Instr Rack 2202-28 L/D Monitoring	U
12E-2816B	W/D Low Pen Power Pen X-200B	Y
12E-2816F	W/D Low Voltage Power Pen X-205E	AG
12E-2816G	W/D Limit Switch and Solenoid Valves in Drywell	E
12E-2901P	Cable Tabulation Cables 20650 to 20699	AE
12E-2903B	Cable Tabulation Cables 22450 to 22499	AA
12E-2903D	Cable Tabulation Cables 22550 to 22599	AC
12E-2903H	Cable Tabulation Cables 22750 to 22799	AC
12E-2903J	Cable Tabulation Cables 22800 to 22849	AL
12E-2903K	Cable Tabulation Cables 22850 to 22899	AF
12E-2904D	Cable Tabulation Cables 23750 to 23799	W
12E-2904J	Cable Tabulation Cables 24000 to 24049	W
12E-2904K	Cable Tabulation Cables 24050 to 24099	Z
12E-2904L	Cable Tabulation Cables 24100 to 24149	R
12E-2904Q	Cable Tabulation Cables 24300 to 24349	U
12E-2906F	Cable Tabulation Cables 26250 to 26299	AA
12E-2908W	Cable Tabulation Cables 29400 to 29449	V
12E-3054	4kV SWGR RX and Turb Bldg	BX
12E-3301, Sheet 1	Single Line Diagram	AJ
12E-3301, Sheet 2	Single Line Diagram	AK
12E-3301, Sheet 3	Single Line Diagram	AJ
12E-3302A	Station K/D 4160V and 480V SWGRs 480V MCCs	U
12E-3305	K/D Turb Bldg 480V SWGR 35, 36, and 37	BC
12E-3311	K/D Turb Bldg 480V MCC 38-2 and 39-2	AT
12E-3321	K/D 250Vdc MCC	AE
12E-3322	K/D 125Vdc Dist	AF
12E-3322A	K/D Turb Bldg 125Vdc Main Bus Dist Panels	V
12E-3391	S/D SW Pumps	K
12E-3416	S/D CRD Hydraulic Pumps 302-3A and 302-3B	U
12E-3416A	S/D CRD Hydraulic System MOVs	C
12E-3430, Sheet 1	S/D CS System 1	AW
12E-3484	S/D Iso Cond System MOVs	R
12E-3501, Sheet 3	S/D PCIS Sensor and Trip Logic	AC
12E-3502, Sheet 1	S/D PCIS Switch Development, Reset Circuit TIP Isolation Recirculation Loop Interlock	AE
12E-3502A	S/D PCI (Drywell) System Reset Circuit System	K
12E-3506, Sheet 1	S/D PCIS Iso Cond Control Logic	AF
12E-3506, Sheet 2	S/D PCIS Iso Cond Control Logic	AG
12E-3506, Sheet 3	S/D PCIS Iso Cond Control Logic Sheet 6	AB
12E-3507	S/D PCIS Iso Cond Valve - Outboard MOV 1301-3	AD
12E-3507A	S/D PCIS MOV 1301-2 Control	U
12E-3507B	S/D Iso Cond RX Inlet Vlv 3-1301-1 and 3-1301-4	M
12E-3575AB	S/D CR Annunciator Panel 903-3 Part 1	H

DRAWINGS

Number	Description or Title	Date or Revision
12E-3653A	W/D 4160V SWGR Bus 33 Cub 1, 2, 3, 4, 5, 6, 7, and 8	U
12E-3664E	Wiring and S/D Turb Bldg 480V MCC 35-2 Part 5	H
12E-3674B	Wiring and S/D RX Bldg 480Vac MCC 38-1 Part 2	AA
12E-3674D	Wiring and S/D RX Bldg 480Vac MCC 38-1 Part 4	AE
12E-3679C	Wiring and S/D RX Bldg 480Vac MCC 39-3 Part 3	I
12E-3681A	Internal W/D 480V MCC Part 1	V
12E-3684A	W/D RX Bldg 250Vdc MCC 3A Part 1	M
12E-3684C	W/D RX Bldg 250Vdc MCC 3A Part 3	Y
12E-3695	W/D MCB Panel 903-3 MSIP Iso Cond 2	DU
12E-3697	W/D MCB Panel 903-3 LPCI CCS 2, CS and Iso Cond 2	CB
12E-3769A	W/D RX Instr and Prot Instr Rack 2203-5 Sect A	X
12E-3770A	W/D RX Instr and Prot Instr Rack 2203-6 Sect A	Z
12E-3788	W/D Instr Rack 2203-28 L/D Monitoring Sect A and B	L
12E-3816B	W/D Low Voltage Power Pen X-204S	AD
12E-3816F	W/D Low Voltage Power Pen X-204M	AK
12E-3901P	Cable Tabulation Cables 30650 to 30699	AB
12E-3903B	Cable Tabulation Cables 32450 to 32499	AA
12E-3903D	Cable Tabulation Cables 32550 to 32599	Y
12E-3903H	Cable Tabulation Cables 32750 to 32799	AB
12E-3903J	Cable Tabulation Cables 32800 to 32849	AG
12E-3904D	Cable Tabulation Cables 33750 to 33799	W
12E-3904J	Cable Tabulation Cables 34000 to 34049	U
12E-3904K	Cable Tabulation Cables 34050 to 34099	Y
12E-3904L	Cable Tabulation Cables 34100 to 34149	U
12E-3906F	Cable Tabulation Cables 36250 to 36299	Y
12E-3908W	Cable Tabulation Cables 39400 to 39449	R
12E-6400B	S/D MOVs Limit Switch Development	C
12E-6400C	MOV Limit Switch Development	G
12E-6401B	Internal/External W/D MOVs Limit Switch	B
12E-6401C	Internal/External W/D MOVs Limit Switch	F
12E-6505B	Cable Tabulation Cables 67250 to 67299	W
12E-6504D	Cable Tabulation Cables 66150 to 66199	AC
12E-6505H	Cable Tabulation Cables 67550 to 67599	Q
12E-6506N	Cable Tabulation Cables 69000 to 69049	S
12E-6506W	Cable Tabulation Cables 69400 to 69449	L
12E-6507H	Cable Tabulation Cables 69950 to 69999	K
12E-6614A	W/D Iso Cond RX Inlet Vlv 2-1301-1 and 4 XFR Panel	E
12E-6614B	W/D Iso Cond RX Inlet Vlv 2-1301-1 and 4 XFR Panel	H
12E-6615	W/D Iso Cond RX Inlet Vlv 2-1301-1 and 4 Control Panel	C
12E-7400A	MOVs Limit Switch Development	L
12E-7400C	MOV Limit Switch Development	E

DRAWINGS

Number	Description or Title	Date or Revision
12E-7401A	Internal/External W/D MOVs Limit Switch	H
12E-7401B	Internal/External W/D MOVs Limit Switch	E
12E-7503S	Cable Tabulation Cables 75600 to 75649	Y
12E-7504B	Cable Tabulation Cables 76050 to 76099	AV
12E-7504D	Cable Tabulation Cables 76150 to 76199	AD
12E-7505K	Cable Tabulation Cables 77650 to 77699	Q
12E-7506W	Cable Tabulation Cables 79400 to 79449	H
12E-7507C	Cable Tabulation Cables 79700 to 79749	G
12E-7614A	W/D Iso Cond RX Inlet Vlv 3-1301-1 and 4 XFR Panel	E
12E-7614B	W/D Iso Cond RX Inlet Vlv 3-1301-1 and 4 XFR Panel	K
12E-7615	W/D Iso Cond RX Inlet Vlv 3-1301-1 and 4 Control Panel	E
12E-8501B	Cable Tabulation Cables 80050 to 80099	H

FIRE PROTECTION IMPAIRMENT PERMITS

Number	Description or Title	Date or Revision
03-154	HPCI Rm Fire Door Inoperable	December 11, 2003
04-026	U2 HPCI Rm Door Open with Hoses	March 15, 2004
04-098	Door 39 (U3 HPCI Rm to East LPCI Rm) Will Be Blocked Open with a Clean Demin Hose Running thru	September 29, 2004
04-100	HPCI Door to LPCI Door 38 Run Hose to Sump	October 1, 2004

PRE-FIRE PLANS

Number	Description or Title	Date or Revision
U2RB-12	Fire Zone 1.1.2.3.A (El 589'-0")	5

PROCEDURES

Number	Description or Title	Date or Revision
DAP-01-11	In-Plant Communication Systems	5
DFPS 4123-08	Fire Water System Flow Test	8
DFPS 4183-04	Unit 2 Heat/Smoke Detector Operability Test	15
DFPS 4183-05	Unit 3 Heat/Smoke Detector Operability Test	14
DOS 7900-02	Emergency Lighting Battery Pack Quarterly Inspection	2
DSSP 0010-01	Determining SSD Paths For Extensive Plant Damage	08
DSSP 0100-14	Safe SD Equipment Inspection	22
DSSP 0100-A1	HSD Procedure - Path A1	25
DSSP 0100-B1	HSD Procedure - Path B1	26
DSSP 0200-L	LPCI/CCSW CSD Method	11
DSSP 0200-S	SDC CSD Method	11
DSSP 0200-T1	Supplying Temp 125Vdc Power to ERVs	7
DSSP 0200-T6	Temp 4kV FD Connections - SDC, LPCI, RBCCW, and CCSW	7

PROCEDURES

Number	Description or Title	Date or Revision
DSSP 0200-T9	Cable Connections for Monitoring RPV Water, Shell, and Flange Temperature Locally	5
OP-AA-201-009	Control of TC Material	4
OP-MW-201-007	FP System Impairment Control	3
SA-AA-122	Handling and Storage of Compressed Gas Cylinders/ Portable Tanks and Cryogenic Containers/Dewars	2

REFERENCES

Number	Description or Title	Date or Revision
----------------------	Dresden Station FP Self-Assessment Report	April 2, 2002
----------------------	Post-Fire SD Capability (Preparation for NRC Inspection)	January 18 thru February 11, 2005
ComEd Letter	Dresden Station Unit 3 ADS Cable Modification	September 16, 1988
Figure 3.1-1	Unit 3 Iso Cond System Sketch (Sheet 2 of 2)	Amendment 12
NFPA 13	Standard for the Installation of Sprinkler Systems	1976
NFPA 72E	Standard on Automatic Fire Detectors	1974
NO-AA-10	Quality Assurance Topical Report	75
NOSA-DRE-03-10	NOS FP Audit Report	July 7, 2003
NRC SER	Compliance with 10 CFR 50, App R, Items III.G.3 and III.L and Exemption Request for HSD Dresden Repairs	July 6, 1989
TRM 3.7	Plant Systems	0

VENDOR DOCUMENTS

Number	Description or Title	Date or Revision
----------------------	Evaluation of Standard for Portable Fire Extinguishers	April 24, 1985
NTSC 93-124	NFPA Code Matrices	1

WORK REQUESTS

Number	Description or Title	Date or Revision
W/O 00065738	Low Air Pressure Trouble Light Lit	September 21, 2002
W/O 00109848	Dessicant in Air Compressor Needs Changed. It's Pink	August 25, 2003
W/O 00754170	D2/3 QTR TSTR Safe SD Equipment Inspection	February 3, 2005
W/O 00765695	Replace Smoke Detector Above SDC Pump	December 20, 2004
W/O 00768228	Smoke Detector Did Not Respond to Testing	December 30, 2004

LIST OF ACRONYMS USED

AC or ac	Alternating Current
ADAMS	Agency-Wide Document Access and Management System
ADS	Automatic Depressurization System
AEER	Auxiliary Electrical Equipment Room
C/R and F/Ss	Cable Routing and Fire Stops
CCS	Containment Cooling System
CFR	Code of Federal Regulations
CR	Control Room
CRD	Control Rod Drive
CS	Core Spray
CSD	Cold Shutdown
DC or dc	Direct Current
DG	Diesel Generator
DMP	Dresden Maintenance Procedure
DNPS	Dresden Nuclear Power Station
DOA	Dresden Operating Abnormal
DPR	Demonstration Power Reactor
DRS	Division of Reactor Safety
DSSP	Dresden Safe Shutdown Procedure
EA	Equipment Attendant
ECCS	Emergency Core Cooling System
ERVs	Electromatic Relief Valves
FD	Feed
FHA	Fire Hazard Analysis
FP	Fire Protection
FPP	Fire Protection Program
FS	Fire Suppression
HPCI	High Pressure Coolant Injection
HSD	Hot Shutdown
HVAC	Heating, Ventilation and Air Conditioning System
HX	Heat Exchanger
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination of External Events
IR	Inspection Report or Issue Report
K/D	Key Diagram
L/D	Leak Detection
LPCI	Low Pressure Coolant Injection
MCB	Main Control Board
MCC	Motor Control Center
MO or MOV	Motor Operated Valve
MSIP	Main Steam Isolation, Pressure Suppression
NCV	Non-Cited Violation

LIST OF ACRONYMS USED

NFPA	National Fire Protection Association
NOS	Nuclear Oversight
NRC	U. S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NUREG	NRC Technical Report Designation
OCA	Owner Controlled Area
OPS	Operations
PA	Public Address
PARS	Publically Available Records System
PCIS	Primary Containment Isolation System
QAP	Quality Assurance Program
QATR	Quality Assurance Topical Report
RBCCW	Reactor Building Closed Cooling Water System
RIS	Regulatory Issue Summary
S/D	Schematic Diagram
SCBA	Self-Contained Breathing Apparatus
SD	Shutdown
SDC	Shutdown Cooling
SDP	Significance Determination Process
SER	Safety Evaluation Report
SSA	Safe Shutdown Analysis
SSCs	Structures, Systems, and Components
SSD	Safe Shutdown
SSEL	Safe Shutdown Equipment List
SW	Service Water
SWGR	Switchgear
TBCCW	Turbine Building Closed Cooling Water System
TC	Transient Combustible
TIP	Traverse Incore Probe
TRM	Technical Requirements Manual
URI	Unresolved Item
V or v	Volt
W/D	Wiring Diagram
W/O	Work Order
WO	Waste Oil
XFR	Transfer