U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/89005(DRP); 50-249/89005(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: January 7 through March 17 and April 11, 1989

Inspectors: S. G. Du Pont
D. E. Jones
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Approved By: J. J. Harrison, Chief
Reactor Projects Section 1B

04/21/89
Date

Inspection Summary

Inspection during the period of January 7 through March 17 and April 11, 1989 (Report Nos. 50-237/89005(DRP); 50-249/89005(DRP))
Areas Inspected: Routine unannounced resident inspection of the licensee's corrective actions associated with previously identified inspection findings, plant operations, maintenance and surveillance activities, safety assessment and quality verification, events, and event reports. Additionally, the licensee's activities associated with heat shrinkable tubing (TI 2500/17) and Technical Specification required reports were evaluated.
Results: During this inspection period the following strengths and weaknesses were noted:

- Two violations were identified during this inspection period. One pertained to an operator error, failure to follow an approved procedure during ground checking operations (Paragraph 3). The second pertained to inadequate post maintenance testing performed in 1986 on the control rod drive (CRD) hydraulic control units (Paragraph 4).

- Several ESF actuations occurred during the inspection period. The majority of these were associated with the undervoltage testing performed as part of the Unit 2 refueling outage. The licensee has performed an

evaluation of the actuations and self-identified several root causes as part of their ESF reduction program. The licensee's corrective actions associated with these actuations are considered to be progressive and an indication of positive management involvement.

- Unit 2 was returned to operation following a refueling outage. The startup was error-free and excellent coverage was provided by the licensee's management and quality assurance staff.

- The licensee's operations staff demonstrated excellent initiative by identifying and correcting additional concerns with the 4KV breakers. In response to the preventive maintenance concerns identified by the NRC Maintenance Team Inspection, the operations staff performed an 100 percent walkdown of the 4KV breakers and identified two additional concerns. The walkdown found two breakers, one 2000 and one 1200 amp rated breaker, installed in the wrong amp rated cubicles. Additionally, the staff identified the root cause as the lack of external amp rating identification. Both of these problems were promptly corrected (Paragraph 3).

DETAILS

1. Persons Contacted

Commonwealth Edison Company

*E. Eenigenburg, Station Manager
*L. Gerner, Production Superintendent
*C. Schroeder, Services Superintendent
C. Allen, Performance Improvement Supervisor
T. Ciesla, Assistant Superintendent - Planning
D. Van Pelt, Assistant Superintendent - Maintenance
J. Brunner, Assistant Superintendent - Technical Services
*J. Kotowski, Assistant Superintendent - Operations
R. Christensen, Senior Operating Engineer
G. Smith, Unit 2 Operating Engineer
K. Peterman, Regulatory Assurance Supervisor
W. Pietryga, Unit 3 Operating Engineer
J. Achterberg, Technical Staff Supervisor
R. Geier, Q.C. Supervisor
D. Sharper, Waste Systems Engineer
D. Adam, Assistant to the Assistant Superintendent - Technical Services
J. Mayer, Station Security Administrator
D. Morey, Chemistry Services Supervisor
D. Saccomando, Health Physics Services Supervisor
*E. Netzel, Q.A. Superintendent

The inspectors also contacted and interviewed 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 and formally at various times throughout the inspection period.

2. Previously Identified Inspection Items (92701 and 92702)

(Closed) Open Item (249/86009-18): SSOMI deficiency 4.1-7. Followup corrective action recommendations contained in the November 24, 1986, letter from Mr. Partlow to Mr. Norelius pertaining to CECo's failure to adequately document 10 CFR 50.59 reviews. The inspector verified the implementation of corrective actions through reviews of 10 CFR 50.59 evaluations pertaining to six plant modifications accomplished during the recent Unit 2 refueling outage. The corrective actions appeared to ensure adequate documentation of the safety reviews. This item is considered to be closed.

(Closed) Open Item (249/86012-09): SSOMI Deficiency 2.2-7. Verify issuance of new procedure for safety evaluations. The inspector verified that administrative procedure DAP 10-2, 10 CFR 50.59 Review Screening and Safety Evaluations, was issued. DAP 10-2 contained requirements that ensured safety evaluations are performed for setpoint changes, temporary alterations, temporary shielding, procedure changes,

and modifications. Additionally, new and special procedures are required to have safety evaluations performed prior to use. This item is considered to be closed.

(Closed) Open Item (249/86012-65): SSOMI Deficiency 2.7-4. The SSOMI identified discrepancies between isolation valve test valves contained in the Technical Specifications, FSAR and surveillance tests, DOS 1600-1 and 1600-18. This item was also identified by the Diagnostic Evaluation (DET) and subsequently resolved in inspection reports 237/88023 and 249/88024.

(Closed) Open Items (237/87007-03 and 249/87006-03): Review the performance of the control rod drives (CRD) during Unit 2 operating Cycle 11 for recurrence of notch 02 events. The inspector reviewed the response of the CRDs during reactor scrams subsequent to corrective actions (documented in inspection reports 237/87007 and 249/87006) and noted that the licensee actions have prevented recurrence. These items are considered to be closed.

(Closed) Unresolved Item (237/88017-28): Diagnostic Evaluation (DET) Item 2.2.3.5. Verify corrections to control testing of ASME Section XI pump testing. This item was reviewed and resolved in inspection reports 237/88023 and 249/88024 (Paragraph 6). Based upon this review, this item is considered to be closed.

(Closed) Unresolved Item (249/86012-66): SSOMI Deficiency 2.7-5. The SSOMI identified that valve cycling tests did not verify proper stroke times as required by ASME Section XI. The Inservice Testing (IST) inspection, documented in inspection reports 237/87026 and 249/87026, verified that the licensee's IST Program, submitted April 15, 1988, adequately addressed and resolved the SSOMI concern. This item is considered to be closed.

(Closed) Bulletins (237/87002-BB and 249/87002-BB): These items are considered to be administratively closed because all required actions were completed and documented in inspection reports 237/87040 and 249/87039.

(Closed) The following inspection items were administratively reviewed and closed by the NRC based upon duplication, or the lack of significance and requirements, or corrective actions being in place to prevent recurrence:

237/85033-03	237/88900-01	249/87005-3L
237/86013-07	237/88067-IN	249/87008-01
237/86018-01	237/87046-IN	249/87032-01
237/87006-1B	237/88014-GL	249/87032-04
237/87009-01	237/88055-IN	249/87032-05
237/87033-01	249/83020-01	249/87032-06
237/87033-04	249/85005-07	249/87032-11
237/87033-05	249/85013-01	249/87037-01
237/87033-06	249/85029-03	249/87037-02

237/87033-11	249/86006-01	249/88003-1L
237/87038-01	249/86015-07	249/88014-GL
237/87038-02	249/86022-01	

No violations or deviations were identified.

3. Plant Operations (71710, 71707 and 93702)

a. Enforcement History

During this inspection period one violation (237/89005-01(DRP); 249/89005-01(DRP)) and two licensee identified violations (10 CFR 2, Appendix C) were identified. The violation pertained to a personnel error while checking for DC grounds.

b. Operational Events

(1) On March 4, 1989, Unit 2 scrammed on low reactor water level from 92% power. The scram occurred while operators were performing DC ground checks on the 125 Volt DC system. During the ground check, an equipment operator opened and then closed a breaker switch which caused a loss of power to the DC powered relays for the oil pressure sensing switches for the reactor feedwater pumps. This resulted in a trip of the previously running Reactor Feedwater Pumps 2A and 2B and an automatic start of the Standby Reactor Feedwater Pump 2C. The resulting vessel water level decrease caused a reactor scram. The equipment operator also opened and closed another breaker switch which caused the isolation condenser and one recirculation system sample valve to close and the inboard Main Steam Isolation Valve (MSIV) DC solenoids to lose power. As vessel water level recovered, the main turbine and Reactor Feedwater Pump 2C tripped at the high vessel water level setpoint of +55 inches. The Turbine/Generator trip caused an automatic transfer of auxiliary power from the Main Auxiliary Transformer to the Reserve Auxiliary Transformer. The corresponding momentary voltage drop during the transfer resulted in a loss of power to all MSIV AC solenoids. The inboard MSIVs automatically closed due to the loss of power to both their AC and DC solenoids. The outboard MSIVs did not close because their DC solenoids were not affected. Operators un-isolated the isolation condenser and allowed it to automatically initiate on high reactor pressure due to the MSIV closure. The MSIVs were subsequently reopened and normal cooldown was commenced.

(2) On March 14, 1989, after just placing the Economic Generation Control (EGC) System into operation on Unit 2, power rapidly increased from 765 MWe to 808 MWe when core flow increased to 100.7 E6 lbm/hr within a two minute time frame. This exceeded the upper total core flow limit of 98.0 E6 lbm/hr prescribed by Technical Specifications for EGC operation. This power increase greatly exceeded the rate limit of 0.2 MW/min., as well as the upper power limit of 780 MWe set on the EGC

controller at the time. In addition, no corresponding alarm was generated when the control room operator manually tripped EGC upon noticing the increase.

(3) On January 21, 1989, while Unit 2 was shutdown during a refueling outage, a Reactor Protection System (RPS) actuation occurred without any rod motion. The actuation occurred while drywell coolers were being started for post outage testing. RPS supply busses 28 and 29 received undervoltage trips during the starting of the coolers and Bus 24-1 (which feeds busses 28 and 29), received a overcurrent trip. The B RPS motor generator was lined up to the A RPS bus while the B RPS bus was lined up to unregulated power. The licensee determined that the cause of the overcurrent trip of bus 24-1 was due to the time-delayed overcurrent relay being set on an incorrect tap setting.

The licensee initiated corrective actions, including a verification of correct tap settings for all relays that were set during the Unit 2 refueling outage. The corrective actions were completed prior to the unit restart on February 19, 1989.

(4) On January 31, 1989, Unit 2 experienced an Anticipated Transient Without Scram (ATWS) protection system actuation initiated by low vessel water level, while shutdown for a refueling outage.

Prior to the actuation on January 30, 1989, check valve 2-263-2-17B was taken out of service for bench test and level transmitters 2-263-23B and 23D were valved out as part of the outage checklist. However, the level transmitter equalizing valve was left in the closed position which caused the instrument to drift and fail downscale; causing the ATWS instrument to actuate on low Rx level. The Shift Foreman checked the instrument and opened the equalizing valve, which allowed the level instrument to go upscale, thus allowing the ATWS system to be reset.

The licensee determined that the root cause of the ATWS actuation was due to inadequate work request instructions and personnel error.

(5) On February 4, 1989, an ESF actuation (reactor scram without control rod motion) occurred on Unit 2 during undervoltage (UV) and logic testing in preparation for returning to operation from the refueling outage. The ESF actuation occurred due to a high signal spike on the APRM and IRM Channels when Transformer 22 to Bus 23 was tripped per the UV test.

The B train of Standby Gas Treatment (SBGT) automatically started per design, but the 2/3 diesel generator and the 2B Low Pressure Coolant Injection (LPCI) pump failed to perform

their automatic functions. The 2B LPCI pump received a start signal but the motor trip coil failed, preventing the pump from starting. The 2/3 diesel generator ventilation fan failed to start because of a failed relay which prevented the diesel from loading onto the bus. The LPCI motor coil and the diesel generator vent fan relay were replaced on February 5, 1989.

On February 5, 1989, a second event related to the UV test occurred. The licensee was in progress of raising vessel level from 138 to 300 inches when the 2/3 and Unit 2 diesel generators automatically started and loaded onto the busses (because of UV testing). The 2B Core Spray and the 2C and 2D LPCI pumps started and injected into the Unit 2 vessel. The vessel level increased from 138 to 178 inches prior to securing the pumps. The root cause of the automatic injection was personnel error during a lineup of test instruments to the high drywell pressure transmitter. The vent on the test rig was inadvertently closed and pressure from the test source leaked through the test pressure regulator to initiate the high drywell pressure signal.

The licensee replaced the leaking test regulator and held a critique on the personnel error. That portion of the test was re-performed successfully.

(6) On February 9, 1989, Unit 2 received a Group 5 primary containment isolation signal (Isolation Condenser). At the time of the isolation, the unit was shutdown with fuel reloaded. The isolation was caused by restoration of primary containment isolation system instrumentation after the primary hydro test and in preparation of the unit startup from the refueling outage. The restoration of the instruments required back filling of the sensing lines and a spurious isolation signal occurred on the Group 5 instruments.

On February 11, 1989, a second Group 5 Isolation occurred when a differential pressure instrument was improperly isolated and the instrument flow check valve was being removed for maintenance.

(7) On February 19, 1989, Unit 2 went critical following a 113 day refueling outage that started on October 30, 1988. Major work accomplished during the outage included the completion of 42 modifications, complete recoating of the torus, main turbine overhaul, human factors control room modifications, replacement of heat damaged cables in the drywell, SRM/IRM/LPRM tube replacement (5 each), vacuuming of all 177 control rod drive guide tubes, mechanical stress improvement of 106 welds, 24 weld overlays and units 2 and 2/3 diesel generator modifications. During the dual unit outage, November 27 to December 5, 1988, the common service water system isolation valves were replaced, ADS cables were separated and the Unit 3 LPCI heat exchanger was repaired.

c. Approach to the Identification and Resolution of Technical Issues From a Safety Standpoint.

(1) Following the March 4, 1989 scram, the licensee conducted portions of DOS 1600-7 and DOP 6900-6 to verify their understanding of the sequence of events. The licensee determined the cause of the event to be an equipment operator who was not following the procedure while checking for DC grounds. The procedure DOP 6900-6, required that the control room shall be notified prior to de-energizing any circuit breakers and prohibited operations of specific breakers. These prohibited breakers were clearly identified in the procedure. However, the operator relied only on the prohibited breakers being distinguishable by red warning labels on the distribution panel to ensure compliance to the procedure. During the refueling outage, these breakers were re-labeled with white labels containing red lettering. This change in labeling contributed somewhat to the inappropriate operation in that the operator had not been made aware of the label change. Since the equipment operator was not following the instructions contained in the procedure, this change of breaker labeling did not prevent the operator from proceeding to check all the circuits on the distribution panel including the prohibited ones. Following the event, the licensee temporarily marked the prohibited breakers with red tape in anticipation of changing to more distinguishable labels. DAP 7-16, Control of System and Component Labeling, Revision 1, prescribes specific administrative controls for changes of plant labels and tags, including review and approval by a shift supervisor. However, this procedure does not govern changes made in conjunction with the on-going major re-labeling program. The licensee is investigating possible program changes to ensure that on-shift crews are notified of major or significant label changes.

The failure of the operator to inform the control room prior to de-energizing circuit breakers and the subsequent de-energizing of circuit breakers prohibited by procedure DOP 6900-6 is considered to a violation of Technical Specifications 6.2.A (237/89005-01; 249/89005-01). The licensee took immediate corrective actions by insuring that all operators were familiar with procedure DOP 6900-6 and the specific identification of the circuit breakers. These actions are considered to be adequate to prevent recurrence and as such, no reply to this violation is required.

(2) During the core flow transient on March 14, 1989 (noted above), the Unit 2 operator took immediate action by tripping the EGC controller. Although the recirculation flow during the transient peaked at 100.7 E6 lbm/hr and exceeded the technical specification limit for EGC operation, the operator's actions limited the magnitude of the transient and prevented possible exceeding of any safety limits. The licensee also took prompt action by restricting any further operation on EGC. Additionally,

a special troubleshooting procedure was developed to control testing and to perform a diagnostic evaluation of the EGC system. Since the licensee took prompt actions to prevent recurrence, the violation was self-identified, the event was reported and the violation of the technical specification would not have otherwise been greater than a Severity Level IV violation, this is considered to be a self-identified violation (per 10 CFR 2, Appendix C) and no notice of violation is issued. The NRC does not generally issue notice of violations in these cases to encourage and support licensee initiatives for self-identification and correction of problems.

d. Responsiveness to NRC Initiatives

For the above events, the inspectors verified that the notifications were correct and timely, if appropriate, that the licensee was taking prompt and appropriate actions, that activities were conducted within regulatory requirements except as noted, and that corrective actions would prevent further recurrence.

(1) While following up on the scram of March 4, 1989, an NRC inspector noted that documentation did not exist for a portion of DOP 6900-6 that was conducted by the licensee to verify the sequence of events that led to the reactor scram. The licensee subsequently re-performed that portion of the sequence and documented the results in the unit log book. The purpose of the licensee's test was to determine the response of the isolation condenser valves. The inspector also witnessed the subsequent unit restart and verified that it was conducted in accordance with appropriate procedures.

(2) Following the March 1989 exit by the NRC Maintenance Team, the licensee's operations staff initiated actions to identify and correct additional concerns regarding the 4KV breakers. The NRC inspection had identified concerns with the preventive maintenance activities associated with the breakers. In response to these concerns, the operations staff performed a 100 percent walkdown of the breakers. The walkdown identified two additional concerns. The first concern identified that two breakers installed in the wrong cubicles. Specifically, the walkdown identified a 2000 amp rated breaker installed in a 1200 amp cubicle and a 1200 amp rated breaker in a 2000 amp cubicle. The second concern pertained to the identification of the breaker amp ratings. The amp rating of a breaker was not identified external to the breaker and requires the breaker to be removed from the cubicle to confirm the rating. The licensee corrected these findings by installing the correct rated breakers into the cubicles and by developing an external amp rating identification on all 4 KV breakers.

The licensee also conducted an evaluation of the safety significance of the two breakers being installed in the wrong cubicles. Since the tripping relays and circuits are

associated with the cubicles and not to the breakers directly, the overcurrent and undervoltage relays were not affected and would have provided adequate protection for both combinations of breaker/cubicle arrangements. The overcurrent settings on the 2000 amp cubicle was within the range of the 1200 amp breaker. This arrangement (1200 amp breaker in a 2000 amp cubicle) was the least conservative and still provided adequate protection.

The above event was identified and corrected by the licensee. Additionally, no prior existing violation pertaining to this event had been identified. Based upon these considerations and the licensee's corrective actions, this is considered to be a licensee self-identified and corrected violation (10 CFR 2, Appendix C) and a notice of violation will not be issued.

e. Assurance of Quality, Including Management Involvement and Control

Management involvement was effective during the above events. The NRC inspectors noted the presence and involvement of the on-shift management representatives during the investigation of these events, as well as the unit restart following the scram of March 4, 1989. The Unit 2 startup from the refueling outage is considered to be an excellent example of management and quality assurance involvement resulting in a error-free evolution. In addition, discussions with other management personnel indicated their concern in addressing the root causes and corrective actions associated with these events.

Several of the above events occurred during undervoltage testing and restoration of instrumentation during the Unit 2 refueling outage. The licensee evaluated these events initially as personnel errors. In addition, these events were included in the licensee's ESF actuation reduction program. The goals of the program are to determine the root cause and corrective actions to prevent recurrence. Since the number of occurrence of events associated with undervoltage testing is considered to be high, the effectiveness of the licensee's program will be evaluated during subsequent inspections. This is an unresolved item (237/89005-03; 249/89005-03).

f. Effectiveness of Training and Qualification

Review of the operating events demonstrated mixed effectiveness of training and qualification. The March 4, 1989, scram was attributed to a personnel error in that an equipment operator failed to follow a procedure and a example of questionable training. The March 14, 1989, operator response to the EGC transient demonstrated excellent training effectiveness.

g. General Observations of Operations

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. In general, operations were conducted in the control room in a professional manner.

The inspectors, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. Housekeeping remained good with a steady improving trend. During the inspection, the inspectors walked down the accessible portions of the systems listed below to verify operability by comparing system lineup with plant drawings, as-built configuration or present valve lineup lists; observing equipment conditions that could degrade performance; and verified that instrumentation was properly valved, functioning, and calibrated.

The inspectors reviewed new procedures and changes to procedures that were implemented during the inspection period. The review consisted of a verification for accuracy, correctness, and compliance with regulatory requirements.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, 10 CFR, and administrative procedures.

The following systems were inspected and verified to be in correct system configurations:

Units 2 and 3 High Pressure Coolant Injection (HPCI)
Unit 2 emergency diesel generator
Units 2 and 3 Low Pressure Coolant Injection (LPCI)

No other violations or deviations were identified in this area.

4. Maintenance and Surveillance (62703, 61726 and 71710)

During this inspection period, the inspectors observed maintenance activities on safety related and balance of plant systems. These activities included replacement of the Unit 2 control room instrumentation and the overhaul of the instrument air compressors and the several control rod drives. In general, these activities were conducted in accordance with approved procedures and standards. The maintenance personnel demonstrated very good maintenance practices and knowledge of the activities being performed.

In addition to the above maintenance activities, the inspectors observed Technical Specification required surveillance testing of the core spray,

LPCI, HPCI and emergency diesel generators on both units. These surveillances were also conducted error-free, demonstrating a sound working knowledge of the activities being performed. During this inspection period, no Technical Specification required surveillances were missed.

The following items were considered during this review: the limiting conditions for operation 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. Additional items reviewed included verification that functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; and activities were accomplished by qualified personnel. Also, the inspectors verified that 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.

a. Enforcement History

During this inspection period, one violation (237/89005-02; 249/89005-02) pertaining to inadequate post maintenance testing performed on the CRD system in 1986 was issued.

b. Operational Events

The following operations events had maintenance and/or surveillance activities as contributors.

(1) On February 20, 1989, the isolation condenser was declared inoperable due to a failed contactor breaker on the service water inlet valve. The breaker was replaced and the condenser declared operable.

(2) On March 14, 1989, the HPCI System was declared inoperable due to a damaged Gland Seal Leakoff (GSLO) pump breaker. After the GSLO pump started to lower HPCI Gland Seal Condenser Hotwell level, the pump failed to automatically stop, although the Hotwell was empty. Attempts to stop the GSLO pump with the control room switch and local stop button also failed. The GSLO pump was tripped by opening and closing the breaker. During troubleshooting a further attempt to start the pump to check operability also resulted in failure of the breaker. Further investigation showed damage to contacts in a relay assembly. The assembly was replaced.

(3) The licensee informed the NRC that defective electrical cables were discovered on December 17, 1988, during installation of the Unit 2 diesel generator pre-lubrication system modification. While making electrical connections, the licensee found that the inner insulation jackets of the 10 AWG wire were cut along

the length of wire. These cuts appear uniformly approximately every 7 inches with a cut length of about 1 inch. The cable was a 3 conductor 10 AWG manufactured by Okonite. The licensee initiated an investigation of the defective cable and contacted the manufacturer. Based upon discussions with the manufacturer, it was determined that the flaw was created during the manufacturing process and was caused by a defective roller on the cable manufacturing machine. It was also determined that the cable was part of a custom made lot that consisted of three reels totalling about 5100 feet. A review of the purchase orders revealed that all three reels were purchased by Dresden. The licensee found that the cable of one reel had also been used for a modification on the Unit 2 Control Rod Drive hydraulic system and that the other two reels were still stored in their warehouse. All of the installed defective cable was removed by the licensee and hold tags were placed on the other two reels of cable to prevent usage. The licensee evaluated this occurrence for Part 21 reportability and requested Okonite, via a formal letter dated January 9, 1989, to provide a root cause analysis and actions to prevent recurrence. Based upon the licensee's evaluation, Part 21 reporting was deemed not applicable. The inspector reviewed the licensee's evaluation and concurred with their conclusion.

(4) On January 30, 1989, the licensee informed the NRC that, during disassembly of two charging water check valves (valves 115) on the control rod drive Hydraulic Control Units (HCUs), the internal ball checks were found to be missing. The disassembling of the valves were being performed as investigative actions associated with the failure of these valves to pass an earlier leak rate test. The test was being performed as part of the licensee's IST upgrade efforts and these check valves had not been previously tested for Unit 2. A similar test had been performed on Unit 3 during the previous refueling outage without any failures. Three HCU charging water check valves experienced excessive leakage during the Unit 2 test, J10, E11 and N13. Valve N13 was inspected but no noticeable damage or deterioration of the internal ball check was found. The internal ball check was replaced for this valve and it subsequently passed the leak rate test. Upon disassembly of valves J10 and E11, the internal ball checks were found to be missing. The valve material is 304 stainless steel and the ball checks are stellite.

Subsequently, the licensee determined that the ball check that was missing from valve E-11 was caused by an inadequate maintenance procedure that was used on the affected HCU during a disassembly of the HCU scram inlet valve in August 1986. Because of the scram inlet and charging water check valve configuration, both valves must be disassembled in order to perform maintenance on either valve. The maintenance work request did not require visual verification of the charging water check valve internals during restoration of the scram inlet valve. The maintenance work request was also inadequate in that a leak test was not specified during post maintenance

testing. The licensee was unable to determine the actual cause of the missing internal ball check from valve J-10. However, it is believed that this missing part was also due to maintenance activities that were performed during or before 1986. The licensee does not believe that the internal ball checks were missing since initial installation. This is based on the fact that the Hydraulic Control Unit is inspected and shipped from the manufacturer as a complete unit. In addition, a review of maintenance practices for the charging water check valve demonstrated that the internal ball check must be extracted from the valve body and will not accidentally fall out.

The following were considered to be contributors to this event:

- Prior to 1988, the licensee did not test the charging water check valves as part of the inservice test (IST) program and as such did not detect the missing internal ball checks.

- Prior to 1988, the licensee's maintenance procedures on the scram inlet valves did not provide adequate instructions to ensure that the charging water check valve internals were installed prior to closure of the scram inlet/charging water check valves connection.

The safety significance of the event was determiend to be extremely low, by the inspector, in that the shutdown margin during the operating cycle was sufficient with all seven control rod drives potentially inoperable at their fully withdrawn positions. Additionally, for the drives to be considered inoperable, the reactor would have to be below 500 psig pressure and all control rod drive pumps inoperable during a reactor startup.

The failure to perform adequate post maintenance testing following maintenance activities on the HCUs is considered to be a violation of Technical Specifications 6.2.A (237/89005-02; 249/89005-02). As noted in Paragraph 4.c of this report, the licensee took prompt corrective actions to prevent recurrence and as such, no reply by the licensee is required.

(5) On February 21, 1989, with Unit 2 at 16% power and Unit 3 at 93% power, the licensee, while performing an engineering review, determined that a Unit 3 design basis accident (loss of offsite power, and a failure of the Unit 2 125 Volt DC system) could cause the loss of both Units 2 and 3 Standby Gas Treatment Systems concurrently. The licensee discussed the sequence of events and compensatory actions taken during a conference call with NRR and Region III on February 21, 1989. The licensee is evaluating possible plant modifications and/or procedural changes to permanently resolve this issue.

c. Approach to the Identification and Resolution of Technical Issues From a Safety Standpoint.

(1) Following the discovery of the damaged relay assembly for the HPCI GSLO pump, a replacement relay assembly was procured and installed. During post maintenance testing, the contacts in this relay assembly were found to also be damaged, such that the HPCI GSLO pump would not start. The problem was traced to a degraded capacitor which allowed pump starting current to be applied across contacts not designed for that current. The contacts in the replacement relay assembly were repaired and the assembly was re-installed. The failed capacitor was also replaced. Subsequent testing demonstrated that the HPCI GSLO pump was operable. Additionally, during troubleshooting of this problem, it was discovered that a wire had been landed on the wrong side of the local start switch contact such that the HPCI GSLO pump could not be started locally. The wire was re-landed in the correct location. Also, it was discovered that the wiring diagram (12E2684B), which shows the local switch, was incorrect. It matched neither the schematic control diagram (12E2532) nor the actual wiring in the field. Errors on the schematic control diagram had been corrected on November 8, 1988, but a corresponding correction to the wiring diagram had not been made. The licensee corrected the drawing error prior to the unit startup.

(2) On November 11, 1988, the licensee performed surveillance, DOS 300-3, "Cold Shutdown CRD Accumulator Charging Water Check Valve Leak Test," on Unit 2. This was the first performance of the leak test on these check valves; previously in 1988 the same surveillance was performed on Unit 3, also for the first time. Initial results of the test indicated seven charging water check valves had failed the the test acceptance criteria and an additional three valves had marginal results. A similar leak test previously performed on Unit 3 had a 100% pass rate. The acceptance criteria of the test required the charging water check valves to maintain the hydraulic control unit (HCU) accumulators at greater than 980 psig (the low pressure alarm setpoint) for five minutes after tripping the operating control rod drive (CRD) pump.

On December 26, 1988, all ten of the affected charging water check valves were flushed with clean demineralized water per an approved special procedure.

On January 6, 1989, the affected check valves were tested for leakage through the scram inlet valve or the charging water check valve. The results of this test indicated that three of the ten check valves did not have leakage through the charging water check valves.

On January 18, 1989, the charging water check valve leak test was again performed on the seven check valves that failed the testing performed on November 11, 1988. Four of these passed the acceptance criteria. The three that failed, CRDs E-11, J-10 and N-13, were then disassembled and inspected on January 30,1989.

The visual inspection of N-13 did not reveal any apparent defects or obstructions. A new internal ball check was installed and the check valve passed the subsequent leak test. However, the visual inspection of the other two check valves revealed that the internal ball checks were missing. Also, see 4.b.(4) above. The licensee informed the findings of the visual inspection to the NRC duty officer via the ENS.

During the review of the event pertaining to the missing HCUs check valve internals, the licensee completed the following corrective actions. The maintenance procedures was revised to ensure that the internal ball checks are installed and tested following maintenance. The licensee investigated the effects on the shutdown margin of having three HCUs failing the charging water leak test. The licensee also investigated the possibility of the stellite ball checks deteriorating and the stellite material being injected into the Scram Inlet Valve or the control rod drives.

The licensee's evaluation of the shutdown margin demonstrated that an adequate margin to criticality was maintained at all times during operating cycle 11. This evaluation assumed that all seven affected control rods would not be able to fully insert during a reactor scram, with low reactor vessel pressure (less than 500 psig), and that both CRD pumps were inoperable or tripped. The charging water check valves are designed to allow the stored water in the HCU accumulator to scram the associated control rod during conditions when reactor vessel pressure is less than about 500 psi and no CRD hydraulic flow is available. However, the licensee's calculations also demonstrated that under the same conditions and assumptions, with the most reactive control rod also inoperable at the fully withdrawn position (rod notch 48), adequate shutdown margin would not have been maintained throughout the operating cycle.

This situation could only have occurred during unit startup and wtih reactor pressure at or near 200 psig, because the flange ball check (internal to the drive mechanism) would still have lifted admitting fluid at reactor pressure (200 psig) under the drive piston with sufficient force (800 psig) to overcome the drive break-away pressure of approximately 260 psid which should drive the mechanism to the fully inserted position. However, at this low pressure without accumulator pressure, the insertion time may be outside the Technical Specification requirements. Above 500 psig reactor pressure, the drive will

fully insert in approximately 5.5 seconds without any assistance from the accumulators.

A review of General Electric's operating and maintenance instruction manual, GEI-92807A, Hydraulic Control Unit, revealed that the postulated drive failures are not related to charging water check valves and that preventive maintenance on these valves is not required except when performing maintenance on the scram inlet valves. This, in addition to the design requirements, indicates that under normal conditions, greater than 500 psig reactor pressure, the drives should fully insert without the assistance of the accumulators.

During startup conditions, the normal rod pattern does not exceed 50% rod density (half of the rods fully inserted with the others at the fully withdrawn position) until reactor pressure is above 500 psig. In this condition the reactor is at less than .1 percent thermal power with very little positive reactivity. Although the licensee did not perform a postulated shutdown margin calculation for this condition, it is easy to derive that if all seven rods were in rod groups that would have resulted in being at the fully withdrawn positions and if the highest worth rod had failed at the fully withdrawn position, the shutdown margin would probably have been achieved as long as the high worth rod was not adjacent to any of the affected rods.

To have exceeded the shutdown margin during startup conditions, several additional errors would have had to occur. First, an operator error concurrent with a failure of the rod worth minimizer must occur to have these two rods adjacent to one another, since the core should be greater than 50% rod density at less than 500 psig (Black and White rod pattern). Secondly, one of the adjacent rods must be the highest worth rod. Both of these conditions are unlikely and did not occur during cycle 11. The highest worth rod, D-9, was not adjacent to any of the seven affected rods. Additionally, not all of the seven rods would have been withdrawn prior to 500 psig because of the black and white checkered rod pattern.

The licensee performed an analysis of the possible injection of the stellite ball check (Haynes Stellite Grade 3 Alloy) into the vessel. The analysis of the material breakdown revealed that the stellite ball contained 27.5 grams of cobalt. The model evaluated two possible methods of breakdown. These were a slow dissolving method evenly over a 500 day period (approximately one operating cycle) and an instantaneous injection method. The cobalt concentration, via the slow injection model, would have resulted in an increase of .25uCi/gm each day. In addition, a sample containing 1 liter of vessel water at these concentrations would range from 4 REM for the slow dissolution, to 200 REM for instantaneous injection. A review of reactor coolant samples during the previous 2 operating cycles indicated that doses of these magnitudes were not

occurring and that concentration of cobalt was stable in a range of $1X10^{-4}$uCi/gm to $1X10^{-3}$uCi/gm.

Based upon the above evaluations, the licensee determined that the safety significance of the event was very low. The inspector reviewed the licensee's evaluations and concurred with the conclusion. These actions demonstrated a very good approach to resolving technical issues from a safety standpoint.

d. Responsiveness to NRC Initiatives.

The licensee demonstrated outstanding performance in response to NRC concerns regarding potential generic implications of the defective Okonite cables by promptly pursuing Part 21 reportability and determination of the extent of the cable problem. Additionally, the licensee took immediate actions to recover all of the defective cable that was installed within the plant.

e. Assurance of Quality, Including Management Involvement and Control.

The licensee demonstrated excellent management and quality assurance involvement in all of the above events. This involvement resulted in improvements of several maintenance activities. Examples included post maintenance test procedures and the detection and removal of defective cables associated with safety related systems.

No other violations or deviations were identified in this area.

5. Safety Assessment/Quality Verification (35502, 90712, 92700)

The inspector reviewed the Quality Assurance (QA) Onsite and Offsite audits performed in 1988. The review was conducted to assess the effectiveness of the licensee's program to identify significant trends. A total of 4 offsite and 56 onsite audits were reviewed, and the findings of the audits were analyzed to determine the existence of significant trends.

The audit findings were analyzed and assigned by the inspector to a matrix containing the 18 QA criteria found in 10 CFR 50 Appendix B - Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants. Apparent trends were noted in the following areas:

1. Criteria II - QA Program
2. Criteria V - Instructions, Procedures and Drawings
3. Criteria VI - Document Control
4. Criteria XVII - QA Records

The apparent trends were then compared to the licensee's trending program. The licensee's program was found to be effective in trending audit

findings and identifying significant trends that may develop. The four areas that the inspector had identified were also found and documented by the licensee. The licensee developed and completed corrective actions to arrest these trends.

No violations or deviations were identified in this area.

6. (Closed) TI 2500/17, Inspection Guidance for Heat Shrinkable Tubing (25017) and IE Information Notice 86-53

The Temporary Instruction required verification of how the licensee addressed IE Information Notice (IN) 86-53, Improper Installation of Heat Shrinkable Tubing. The IN addressed specific problems on Unit 3 that were identified by the Safety System Outage Modification Inspection (SSOMI). Subsequent to the SSOMI findings, the licensee committed to inspect Unit 2 Raychem splices. A total of 466 splices (56%) were inspected with a total of 7 deficiencies being identified. All of the improperly installed splices, on both Units 2 and 3, were corrected prior to returning the units to service. The SSOMI followup team inspected several of the reworked Raychem splices and considered them to be acceptable.

The licensee revised DMP 040-25, Installation and Removal of Raychem Heat Shrink Products, in July 1987 to incorporate the vendor's application guide that includes drawings for different splice configurations and a checklist that preplans and prepares for each splice. For example, the procedure includes attributes such as, verification that splices are not installed over the braiding, verification of proper splice kit (size and environmental qualification), adequate splice overlap, minimum bend radius, and that the splices are properly cooled prior to placement in conduit or junction box.

Raychem has provided two hands-on workshops to the electrical maintenance staff and the quality control (QC) inspectors in October 1985 and January 1988. The inspector reviewed several work requests regarding the installation of Raychem splices and found them to be in compliance with DMP 040-25. The installers and QC inspectors were properly trained and qualified and the splices were properly installed and met EQ requirements. This TI and IN are considered closed.

7. Licensee Event Reports Followup (93702)

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 action to prevent recurrence had been accomplished in accordance with Technical Specifications.

(Closed) LER 249/88006-01: HPCI Area Temperature Switches Exceeded Technical Specification Limit Due to Instrument Setpoint Drift.

This supplemental report was issued to provide an update regarding the corrective actions implemented to resolve the High Pressure Coolant Injection (HPCI) room and Main Steam Line (MSL) tunnel temperature switch

calibration problem. The cause of the HPCI temperature switches' failure to trip within the required limit was attributed to instrument setpoint drift. The corrective actions included establishing a task force to review the instrument configuration and calibration methods. Additional testing and augmented inspections of the temperature switches were also performed. As a result of this review, an improved calibration method was implemented. Replacement of the temperature switches is also under review.

(Closed) LER 237/88022-01: Heat Damage to Upper Elevation Drywell Components Due to Closed Ventilation Hatches. This supplemental report was issued to summarize the results of the task force investigation and to summarize repair work either completed or scheduled as a result of this event. The cause of the excessive temperatures on the fourth and fifth drywell elevations was attributed to lack of forced ventilation to the fifth elevation (the Reactor Head Area) that resulted from the ventilation hatches being closed. The root cause of this event was attributed to deficiencies in two procedures (DOS 1600-10 and DMP 1600-5). The procedures were revised to clearly specify the required verification that the two manway hatches, two ventilation supply hatches and two ventilation return hatches in the refueling bulkhead are open. In addition, a checklist in DMP 1600-5 was revised to include a sign-off that the ventilation and manway hatches were left wired open. Repair/ replacement work on valves, cables, insulation, paint, snubbers and motors were completed prior to Unit 2 restart. This LER is currently being evaluated for potential enforcement action.

LER 249/88006-01 was reviewed against the criteria of 10 CFR 2, Appendix C, and the incidents described meet all of the following requirements. Thus no Notice of Violation is being issued for the LER.

a. The event was identified by the licensee,
b. The event was an incident that, according to the current enforcement policy, met the criteria for Severity levels IV or V violations,
c. The event was appropriately reported,
d. The event was or will be corrected (including measures to prevent recurrence within a reasonable amount of time), and
e. the event was not a violation that could have been prevented by the licensee's corrective actions for a previous violation.

No violations or deviations were identified in this area.

8. Report Review

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Reports for January and February 1989. The inspectors confirmed that the information provided met the requirements of Technical Specification 6.6.A.3 and Regulatory Guide 1.16.

9. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, items of noncom-

pliance, or deviations. Unresolved items disclosed during the inspection are discussed in Paragraph 3.e.

10. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on March 17 and April 11, 1989, 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.