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REGION I

Report No. 50-219/89-21

Docket No. 50-219

License No. DPR-16 Priority -- Category C

Licensee: GPU Nuclear Corporation

1 Upper Pond Road

Parsippany, New Jersey 07054

Facility Name: Oyster Creek Nuclear Generating Station

Inspection Conducted: September 3, 1989, - October 7, 1989

Participating Inspectors: E. Collins, Senior Resident Inspector
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Approved By: C. Cowgill, Chief, Reactor Projects Section 4B — 11/3/89 Date

Inspection Summary: Inspection September 3, 1989 - October 7, 1989 Report No. 50-219/89-21)

Areas Inspected: The inspection consisted of 261 hours by resident and region-based inspectors. The areas inspected included observation and review of plant operational events (paragraph 2.0), reactor scram caused by surveillance testing (paragraph 3.0), emergency diesel generator troubleshooting and maintenance (paragraph 4.0), control room habitability (5.0), core spray booster pump trip (paragraph 6.0), HFA relays (paragraph 7.0), missed surveillance (paragraph 8.0), no senior licensed operator in the control room (paragraph 9.0), "B" control rod drive pump breaker failure (paragraph 10.0), isolation condenser return valve failure (paragraph 12.0), material procured from the Meredith Corporation (paragraph 13.0), maintenance observations (paragraph 14.0), surveillance observations (paragraph 15.0) and previously opened inspection findings (paragraph 19.0).

Results: Overall the plant was operated in a safe manner. Two plant startups and one plant shutdown were performed with minor problems. Plant response and operator response to a plant trip from 100 percent power was very good. Replacement of the M1B main transformer was well planned and executed.

A problem was experienced in the area of work control. Troubleshooting and maintenance performed on an emergency diesel generator was not performed in accordance with procedures and instructions appropriate to the circumstances. This event was similar to one identified by an NRC inspection team during the last refueling outage. These events are violations.

One licensee identified violation of technical specification shift manning requirements occurred. The violation involved an event where no senior licensed operator was in the control room for six minutes. The licensee identified this event and implemented prompt and effective corrective actions.

Two instances of a lack of documentation were identified. One involved a modification to install a timer in the control room heating, ventilation and air conditioning system; the other involved removing and installing leads controlled by a temporary variation. Both items are unresolved.

One event involved a missed surveillance. This event raised questions on the methodology which the licensee uses to calculate test due dates. This item is unresolved.

Nine previously opened inspection items were closed; five items were updated.

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DETAILS

1.0 Personnel Contacted

Licensee Personnel

T. Akos, Technical Functions
* K. Barnes, Licensing Engineer
R. Barrett, Plant Operations Director
M. Bradley, I & C Job Coordinator
* G. Busch, Licensing Manager
B. DeMerchant, Licensing Engineer
A. Dickinson, Plant Engineering
R. Farrell, Rad Engineer
R. Fenti, QA Mod/OPS Mgr.
P. Fischler, Electrical Supervisor
* E. Fitzpatrick, Vice President & Director
* V. Foglia, Technical Functions Manager
T. Genna, MCF I & C
A. Hawley, Plant Operations Engineering
E. Johnson, MCF, I & C Superintendent
D. Jones, Electrical Engineering
* D. MacFarlane, Site Audit Manager
P. Manning, QC
R. Markowski, QA Program Development/Audit Manager
K. Mulligan, Plant Operations
O. Perez, Plant Engineering
D. Ranft, Plant Engineering
* J. Rogers, Licensing
* A. Rone, Plant Engineering Director
* P. Scallon, Plant Operations Manager
E. Scheyder, MCF Director
R. Skelskey, Elec. Mtce. Supervisor
* M. Slobodien, Radiological Controls Director
K. Smith, I & C Job Coordinator
* T. Snider, MCF Maintenance Manager
K. Wolf, Rad Engineering Mgr.

NRC Personnel

* M. Banerjee, Resident Inspector
* E. Collins, Senior Resident Inspector
* D. Lew, Resident Inspector

* Denotes attendance at exit meeting.

2.0 Plant Operational Review

2.1 Chronology of Operational Events

At the beginning of this inspection period, the plant was operating at 68 percent rated thermal power. After the failure of one of the two main transformers on 7/11/89, power was limited by the capacity of the remaining transformer. The following lists the major plant events which occurred during this inspection period.

-- 9/4/89 #1 Emergency Diesel Generator was declared inoperable after failing a surveillance. Technical specifications allow plant operation to continue for up to seven days with one emergency diesel inoperable. Details of this event are described in paragraph 4.0.

-- 9/7/89 While placing a reactor feedwater string into service, reactor level dropped approximately 20 inches. The feedwater string had inadvertently drained causing the reactor level transient. Details of this event are described in paragraph 2.2.

-- 9/9/89 Reactor power was reduced to 21.5% and the turbine was taken off line to allow connecting the replacement for the M1B transformer.

-- 9/11/89 A plant shutdown as required by technical specifications was performed because the #1 Emergency Diesel Generator could not be returned to service. Details of this event are described in paragraph 4.0.

-- 9/11/89 During the plant shutdown, the "A" Isolation Condenser condensate return valve, V-14-34, failed to operate. Details of this event are described in paragraph 12.0.

-- 9/16/89 The licensee discovered the knife switch supplying DC control power to vital 460 volt breakers was mispositioned. As a result, nonvital DC control power had been supplied to vital 460 volt breakers. The details of this event are documented in Inspection Report 50-219/89-23.

-- 9/17/89 A plant startup was performed. Prior to startup, the following items were completed. The #1 Emergency Diesel Generator was repaired and declared operable. The M1B transformer was installed. The condensate return valve, V-14-34, was tested and returned to service. Immediate corrective actions to address the mispositioned knife switch were completed.

   The work on the M1B transformer was well planned and executed. The startup was conducted with only minor problems. Twenty-four hour coverage was provided by Operations management during the startup.

-- 9/20/89 Plant reached 100 percent rated thermal power.

-- 9/22/89 Core Spray booster pump NZ03 tripped during a surveillance and was declared inoperable. Technical specifications allow plant operation to continue for up to 15 days with one core spray pump inoperable. Details of this event are described in paragraph 6.0.

-- 9/22/89 A reactor scram occurred from 100 percent power as a result of personnel error during performance of a surveillance. Details of this event are described in paragraph 3.0.

-- 9/24/89 A reactor startup was performed. Prior to startup, the core spray booster pump breaker was repaired and the pump declared operable.

Startup was performed without significant problems. Management presence was observed during the startup. Site management decided to delay plant startup for 24 hours to allow the xenon decay rate to decrease. This decision was made to minimize the rate of positive reactivity addition from xenon decay during startup, thereby minimizing challenges to the operators.

-- 9/26/89 The plant reached 100 percent rated thermal power.

-- 10/6/89 Reactor power was reduced to 84 percent to repair a leaking valve on hydraulic control unit 42-43. Reactor power was returned to 100 percent three hours later.

2.2 Reactor Water Level Transient while Starting Reactor a Feed Pump

On 9/7/89 while operating at 68% power, the licensee attempted to place the B reactor feed pump (RFP) into service. The pump had been out of service to complete maintenance on the lubricating oil system.

Safety tags were removed, and the feedwater string inlet valve (V-2-8) was opened to repressurize the piping and feedwater heater. In accordance with Station Procedure 317, Feedwater System, the feed pump was started with the feedwater string outlet valve (V-2-11) closed. Feed pump flow was established through the minimum flow valve.

After approximately 10 minutes the heater string outlet valve was opened. About 15 seconds after the valve started opening, a single loud bang was heard and the operator noticed reactor water level decreasing. A and C reactor feed pumps reached maximum flow conditions. The operator responded by closing the heater string outlet valve V-2-11. Reactor power was reduced using the recirculation system.

Reactor water level decreased approximately 20" and then quickly recovered as feedwater level control was still in automatic.

The licensee convened a group to identify the cause of the transient and also to identify what actions were necessary to assure safe plant operation. This group concluded that during the period of time the feedwater string was tagged out of service, the piping and feedwater heater drained to the hot well through the open minimum flow valve. Upon return to service, the voided feedwater piping and heater filled rapidly with water, causing the level transient. The loud noise was attributed to rapid closure of the feedwater check valves (see paragraph 13.1). Station Procedure 317 did not address returning a depressurized feedwater string to service with the plant at power. The root cause was determined to be inadequate procedural guidance.

Licensee corrective actions consisted of the following:

- A complete filling and venting of the B feedwater string was done.

- A visual inspection of feedwater piping and supports was performed. A leak on a feedwater check valve was identified that may have been caused by this transient.

- After return to service, monitoring of the performance of the B feedwater heater string identified no leakage or damage.

- Changes to Station Procedure 317 were implemented to provide direction for returning a de-pressurized feedwater string to service.

The inspectors observed portions of the review conducted by the licensee and reviewed operator response to the transient.

The inspectors concluded the licensee review was thorough and correctly identified the root cause of the transient. A rough calculation of the volume of water lost in the reactor vessel corresponded approximately to the volume which would be available in the B high pressure feedwater heater. This corroborated the licensee's conclusion. The temporary changes to Station Procedure 317 were reviewed. No unacceptable conditions were identified.

Control room operator response to this transient was prompt, and probably prevented a scram on reactor low water level. No unacceptable conditions were identified.

2.3 Control Room Tours

Routine tours of the control room were conducted by the inspectors during which time the following documents were reviewed:

-- Control Room and Group Shift Supervisor's Logs;

-- Technical Specification Log;

-- Control Room and Shift Supervisor's Turnover Check Lists;

-- Reactor Building and Turbine Building Tour Sheets;

-- Equipment Control Logs;

-- Standing Orders; and,

-- Operational Memos and Directives.

No unacceptable conditions were identified.

2.4 Facility Tours

Routine tours of the facility were conducted by the inspectors to make an assessment of the equipment conditions, personnel safety, and procedural adherence and regulatory requirements. The following areas were among those inspected:

-- Turbine Building

-- Vital Switchgear Rooms

-- Cable Spreading Room

-- Diesel Generator Building

-- Reactor Building

-- New Radwaste Building

-- Old Radwaste Building

The following additional items were observed or verified:

a. Fire Protection:

-- Randomly selected fire extinguishers were accessible and inspected on schedule.

-- Fire doors were unobstructed and in their proper position.

-- Ignition sources and combustible materials were controlled in accordance with the licensee's approved procedures.

-- Appropriate fire watches or fire patrols were stationed when equipment was out of service.

b. Equipment Control:

-- Jumper and equipment mark-ups did not conflict with technical specification requirements.

-- Conditions requiring the use of jumpers received the prompt attention of the licensee.

c. Vital Instrumentation:

-- Selected instruments appeared functional and demonstrated parameters within Technical Specification Limiting Conditions for Operation.

d. Housekeeping:

-- Plant housekeeping and cleanliness were in accordance with approved licensee programs.

Minor housekeeping deficiencies which were identified were promptly corrected by the licensee. No other unacceptable conditions were identified.

3.0 Surveillance Test Causes Reactor Scram

3.1 Event Description

On 9/22/89, while operating at full power, the plant scrammed on an anticipatory turbine trip signal. The main turbine had tripped on a high reactor water level signal. The rapid closure of the turbine stop valves caused reactor pressure to increase. It peaked at approximately 1077 psig. The following equipment response was received:

- Both isolation condensers initiated,

- A, B, D, and E electromatic relief valves (EMRV) lifted, and

- All five reactor recirculation pumps tripped.

Control room operators responded to stabilize plant conditions. Both isolation condensers were secured, and electromatic relief valves were verified to be closed. A plant cooldown to cold shutdown was initiated to permit restarting of the reactor recirculation pumps.

3.2 Event Review

A post trip review group (PTRG) was convened to review the cause of the scram and the plant transient response.

Immediately after the scram, Instrument and Control (I & C) technicians called the control room. They indicated the scram probably had been caused by reactor water level transmitter manipulations. The technicians had been performing surveillance test 619.3.013, "Reactor High/Low Level Test and Calibration."

The PTRG interviewed the technicians and reviewed the sequence of events just prior to the reactor scram. It was determined that return of a water level transmitter to service without removing the calibration test equipment caused the depressurization of the instrument low side reference leg. Other instruments connected to that leg sensed an artificially high differential pressure indicating high reactor water level. The high reactor water level causes a turbine trip.

The PTRG concluded the root cause of this event was personnel error. The procedure step specifying the calibration test equipment removal prior to returning the transmitter to service was not performed. The technician did not notice the equipment was still installed when returning the transmitter to service.

Licensee review (Human Performance Evaluation System, HPES) of the event identified some weaknesses in the execution of this test. These weaknesses centered around work practices. Specifically, weaknesses were noted in task preplanning and the use of procedure step sign-offs. Unexpected role changes and outside distracting activities also may have contributed to the human error. Licensee corrective actions identified steps to address the weaknesses in performance.

PTRG noted two anomalies associated with the equipment response to the trip.

The first anomaly was that "C" electromatic relief valve did not open and that the plant computer showed that it was open. A calibration test found the lift set point for the valve to be 1089 psig, which was above the peak pressure reached during the transient. This value was within the allowable range. PTRG concluded that the valve set point was not reached during this transient and thus, the valve was not required to have actuated. The anomaly with the computer indication was not explained by the review group. This was an outstanding item to be completed after plant restart. Site computer applications is to review the computer input points for the EMRV acoustic monitors and confirm the appropriate acoustic monitors correspond to the computer point identification labels.

The second anomaly was that a ground condition developed on the "C" 125-Volt DC distribution system. Shortly into the transient the ground condition cleared. Investigation showed that no water had sprayed onto the electrical connections associated with this instrument rack. Because the ground condition cleared, the licensee was not able to identify the cause of the ground.

3.3 NRC Review of the Transient

NRC inspectors observed portions of the PTRG meeting and reviewed the PTRG report.

The licensee's rationale and basis for addressing the two anomalies was reviewed. It was concluded that the EMRVs responded as designed, as the "C" valve was not required to lift. In regard to the acoustic monitor computer indication, the licensee's approach to resolve this problem after startup was reasonable. Overall it was concluded the plant responded as designed. No unacceptable conditions were identified.

The inspector reviewed plant parameters in response to the transient, including reactor pressure, reactor water level, reactor power, EMRV position indication, feedwater flow and steam flow. This plant response was compared to the plant response associated with a trip from full power which occurred on 5/18/89. It was concluded the plant response was the same. The only difference identified was the two additional electromatic relief valves which lifted in this trip. It was concluded this was due to actual valve setpoints being exceeded in the September trip where they were not exceeded in the May trip. No unacceptable conditions were identified.

NRC inspectors evaluated the operator response to this event and concluded the operators responded promptly and correctly to stabilize plant conditions. Overall operator response was evaluated as excellent.

NRC inspectors reviewed the licensee conclusions and actions in regard to the human performance aspects of the trip. It was concluded that the licensee has identified important factors associated with the technicians missing the surveillance test step. Their corrective actions should increase technician awareness of surveillance test performance and minimize the likelihood of another occurrence of this nature.

4.0 Emergency Diesel Generator Maintenance (EDG)

During surveillance testing on 9/4/89, #1 EDG experienced large load swings. During troubleshooting of this erratic load control, the diesel failed to start. It was declared inoperable, and the plant entered a 7-day technical specification action statement.

Licensee troubleshooting concluded the failure to start was due to high electrical resistance in the DC starter motor slow roll circuitry combined with high mechanical resistance to diesel engine roll. It was observed that about an hour after diesel shutdown, there was increased mechanical resistance to diesel roll. This was attributed to residual engine heat and the existing mechanical resistance of the new engine power packs. An attempt to start the diesel under these conditions using the slow roll circuitry would result in high starter motor currents and low DC control voltage. The resultant control voltage was low enough to allow the starting contactors to open and cause a starting sequence failure. This slow roll circuitry is only used during manual start of the diesel. During automatic emergency start of the diesel this circuitry is bypassed. The licensee implemented a modification to lower the electrical resistance which was tested satisfactorily.

Licensee troubleshooting, at this point, could not identify the problem with load instability, and on 9/11/89 the plant was shut down due to expiration of the 7-day action statement. To correct the load stability problem additional maintenance activities were performed, including replacement of the governor control box and the governor actuator.

On 9/14/89, an NRC inspector observed maintenance activities associated with #1 EDG. It was noted that the diesel rocker arms had been removed and that electricians were in the process of removing the diesel starter motor. The rocker arms had been removed to support replacement of the engine fuel injectors. The inspector asked to review the work package, but it was not at the work site, it was with the job supervisor. The job package was subsequently reviewed in the job supervisor's office.

Work on #1 EDG was being performed under an immediate maintenance short form which had been initiated on 9/4/89. Station Procedure 105, Control of Maintenance, allows "immediate maintenance" work that must be completed on an urgent basis to be performed without the planning and control normally included in the job order process. The role of planning and control is assumed by the job supervisor under the direction of the Group Shift Supervisor (GSS). The immediate maintenance short form work package did not address removal of the diesel starter motor or replacement of the diesel fuel injectors.

The Site Director was notified that undocumented maintenance was being performed on #1 EDG. In addition, the immediate maintenance short form process was being used for complicated maintenance and troubleshooting. This is beyond the intent of the immediate maintenance process.

Work on the diesel was stopped until a new job order receiving the review and approval normally applied to work on safety related equipment could be generated.

Site Quality Assurance reviewed previously completed immediate maintenance short forms to assess the quality of past work. No adverse conditions were found. The licensee concluded there was not a programmatic problem with the use of the immediate maintenance short form process. However, the licensee stated their intention to implement additional controls and limitations on the use of the immediate maintenance short form process.

NRC review concluded the scope of work performed on #1 EDG was outside that allowed by Station Procedure 105 immediate maintenance process. In addition, it was not appropriately approved, controlled or documented. Site personnel were content to accept technical direction as a substitute for work control. The work scope under the immediate maintenance short form had been increased by adding line items to the job package. This did not provide for review and approval of the work package revision. This was done without the supervision of the GSS as required by Station Procedure 105. Overall, maintenance activities on the #1 EDG were inappropriately approved, controlled and documented.

This finding is similar to that of an NRC inspection team (Report 50-219/88-203) on the same piece of equipment during the last refueling outage. The team identified the following:

- The licensee incorrectly performed complex maintenance on #1 EDG using a vendor generated procedure.
- The licensee used handwritten, not reviewed and unapproved instructions and data sheets to measure contact resistances on #1 EDG relays.
- The licensee made physical changes to #1 EDG system hardware after final QC acceptance had been performed.
- The licensee performed extensive post maintenance testing on #1 EDG using a handwritten, not reviewed and unapproved test procedure.

The team concluded this failure to review and approve the complex maintenance testing on #1 EDG prior to its performance was a violation of 10 CFR 50, Appendix B requirements for procedures control and was documented as an unresolved item.

Licensee response to the NRC team finding, as indicated in GPUN letter dated 1/12/89, was that all unapproved work and testing performed on #1 EDG was incorporated into a revised work package which was reviewed in accordance with approved procedures. Completed work was found to be technically accurate. This review ensured that no work had been performed that would adversely affect operability or reliability of #1 EDG. No root cause was identified.

The use of reviews of work and testing performance after the fact in place of approved procedures for complex maintenance testing indicates the acceptance by the licensee of informal technical direction in lieu of appropriate work control processes. The acceptance of informal technical direction appears to be a result of pressure to return equipment to an operable status within allowable technical specification requirements or to support reactor startups. These factors apparently resulted in a misapplication of the immediate maintenance short form process which resulted in this procedure being used for activities for which it was not intended.

10 CFR 50, Appendix B criterion V requires activities affecting quality to be prescribed by documented instructions, procedures or drawings of the type appropriate to the circumstances. These activities shall be accomplished in accordance with these instructions, procedures or

drawings. Oyster Creek Operational Quality Assurance Plan, Section 6.11, requires that construction, maintenance or modification of equipment shall be preplanned and performed in accordance with written procedures, instructions or drawings appropriate to the circumstances which conform to applicable code standards, specifications and criteria. The removal of #1 EDG starter motor on 9/14/89 by maintenance personnel without this work being being preplanned or approved is a violation of NRC requirements (50-219/89-21-01). This violation closes the unresolved item of Report 50-219/88-203.

The cause of #1 EDG load instability was finally traced to a loose electrical connection which was repaired.

5.0 <u>(Open) Unresolved Item 86-38-03 Control Room Habitability</u>

A control room habitability test indicated control room in-leakage was unacceptably high with the bathroom and kitchen damper in the open position and the fan running. In order to control in-leakage, the licensee agreed to administratively control the bathroom fan and damper. However, NRC inspection found that the fan and damper were not controlled. This item was opened to track resolution of the concern.

The plant technical specifications limit the control room in-leakage to 2000 cfm in the partial recirculation mode. During the last refueling outage, a significant modification was made to the control room HVAC system by adding redundant trains. It was determined the 2000 cfm was not limiting for radiological dose calculations. However, the licensee concluded from toxic gas considerations (release from 150 lbs chlorine storage tanks on site) that a new limit of 1750 cfm should be imposed. Site procedures require operation of control room HVAC in the full recirculation mode upon an on site chlorine release. Test data indicated the control room in-leakage in full recirculation mode could exceed 1750 cfm with the bathroom fan running and damper open.

To control operation of this bathroom fan, the licensee installed a five minute timer during early 1987. With this control, the probability of a chlorine release while the bathroom fan is running is minimized. The licensee is currently preparing a plant technical specification change request for the control room HVAC system to address the system modification and the new in-leakage limit. Credit is being taken for the five minute timer to limit bathroom fan operation. Administrative controls were initially removed after the timer installation, but were reinstalled during review of this item.

To install the timer a MCF short form was used, but this documentation could not be located. Additionally, the timer is not included in any plant drawing.

The use of a short form to install a design modification is not adequate. Installation of the timer is a plant modification and should have been subjected to formal design control measures. This instance is similar to a violation identified in Inspection Report 89-04 regarding a change to the intermediate range monitor range switch. In that inspection report the licensee was asked to identify controls in their work authorization review process which would identify plant configuration changes so that appropriate controls can be instituted. This information was not included in the response.

In GPUN letter dated May 26, 1989, the violation in Inspection Report 89-04 was evaluated as an isolated instance. However, a similar concern was raised in Inspection Report 88-16 when a short form was revised to include work that constituted a change to the plant configuration. Additionally, with the example of the timer installation stated above, these events point toward a potential weakness in the configuration control system.

This item will remain unresolved pending review of licensee's technical specification change submittal on the control room HVAC and response to the configuration control questions raised in Inspection Report 89-04.

6.0 Core Spray System Temporary Variation

6.1 Background

Inspection Report 50-219/89-14 documented an event in which the breaker to core spray booster pump, NZ03B, tripped on 6/16/89 while performing a surveillance procedure. Two similar events occurred earlier in the year when the same breaker tripped during surveillance testing. Although the licensee conducted extensive troubleshooting on the breaker in June and subsequently replaced the breaker, the root cause for the breaker trips could not be determined. In an effort to obtain additional information in the event the breaker trips again, chart recorders were installed to monitor the system performance during surveillance testing. The chart recorders were installed and controlled in accordance with Station Procedure 108, Equipment Control, which specifies the temporary variation requirements.

6.2 Details

During the performance of the Core Spray Auto Actuation Surveillance on 9/21/89, Instrument and Controls technicians reached a step in the procedure where the expected voltage measurement was not obtained. The expected voltage was zero; however, the technicians noted a 60-volt direct current (DC) reading. The technicians stopped the surveillance; and, the cause of the problem was investigated.

On 9/22/89, the surveillance was recommenced. Based upon discussions with licensee personnel, the surveillance was recommenced because it was determined that the unexpected voltage was from the temporarily installed chart recorder. It was also determined that the chart recorder was only required to monitor the system during the start of the core spray booster pump. To continue with the surveillance, the chart recorder lead was lifted to remove the 60 volt DC reading. The chart recorder lead was reinstalled prior to performing the portion of the surveillance which required the operation of the booster pump.

When the core spray booster pump was started, the breaker tripped. The symptoms of the breaker trip were different than that observed on 6/16/89. The trip was determined to be the failure of the breaker Microversa Trip Unit. The unit was subsequently replaced; and, the breaker tested satisfactorily and declared operable.

The information from tha chart recorder after the breaker tripped showed an unexpected and incoherent trace. It was determined that the lead to the recorder was connected to the wrong terminal. Plant Engineering reviewed the impact of the mispositioned lead on core spray system operability and concluded operability was unaffected. The resident inspectors independently reviewed any potential impact on operability and also concluded operability was not affected. The chart recorder lead was moved to the correct position. A deviation report was generated to address the mispositioned chart recorder lead.

A deviation report was not written on 9/21/89 when the surveillance testing could not be completed. The disposition of the incomplete surveillance was not documented or captured in the licensee's corrective action system. Additionally, the resolution of the unexpected voltage obtained during surveillance testing did not identify that the chart recorder lead was mispositioned. A deviation report for the incomplete surveillance not was generated until 9/29/89.

During this event, the leads to the chart recorder were moved twice. They were moved once on 9/21/89 to allow surveillance testing to continue, and moved again on 9/22/89 to put the lead on the correct terminal. The controls specified in the equipment control procedure would require the temporary variation to be cleared in order to remove the chart recorder lead. Reinstalling the chart recorder lead would require reissuing the temporary variation. Installing and removing temporary variations would require independent verification.

The inspector reviewed Temporary Variation 89-057. It was noted that the chart recorder lead movement and the required administrative controls for these movements were not documented.

6.3 Conclusion

Several weaknesses were evidenced by this event.

-- The resolution of the unexpected voltage during surveillance testing was not documented or captured in the licensee's corrective action system.

-- This resolution did not identify the mispositioned chart recorder lead prior to recommencing the surveillance.

-- The lead removals and installations were not documented in temporary variation 89-057. This lack of documentation raises questions on how the chart recorder leads were controlled.

At the time of the exit meeting, the critique to determine the circumstances surrounding this event was not yet conducted. A three week period had already elapsed.

Documentation of the removal and reinstallation of the chart recorder leads will be unresolved pending the identification of what controls were taken in regard to the temporary variation, the evaluation of the appropriateness of the controls, and the determination of whether these controls met procedural requirements (50-219/89-21-02).

7.0 HFA Relay

On 9/13/89, during a surveillance test, an HFA relay in the reactor protection system did not go to the fully open position when deenergized. The relay was considered operable because the normally open (NO) contacts performed their intended trip function. Because of the anomaly; however, this relay was replaced and a deviation report was initiated. A similar event happened last month when a reactor high pressure scram relay did not fully open when deenergized (Report 50-219/89-17).

The licensee consulted with the relay manufacturer, General Electric (GE), to determine the cause of the observed anomalies. Mechanical binding of the armature, as discussed in GE Service Advisory Letter (SAL) 188.1, dated 11/14/86, was identified as the cause of the events.

GE SAL 188.1 indicated that HFA relays manufactured between January 1983 and October 1986 could have a defect due to incorrect location of an armature stop tab. It recommended an inspection method for identification of armature binding and suggested armature or relay replacement if binding was identified. NRC Information Notice 88-14, Potential Problems with Electrical Relays, dated 4/18/88, also informed the licensees about this mechanical binding problem.

The licensee replaced HFA relays during the 10R and 11R refueling outages with relays that were manufactured during the time frame identified in the GE SAL. However, a determination was made in 1988 that inspection of these relays per SAL 188.1 was not necessary. The basis for this determination was the preventive maintenance program (PM) existing for these relays. The PM program had been revised to include a requirement of listening for unusual noises, which would pick up any loosening of the armature. Licensee evaluation concluded there was a high probability of damaging or misaligning installed relays while performing the recommended inspection.

The licensee concluded the two instances of armature binding referenced in the SAL were not a sufficient sample base to warrant inspection of already installed relays. The basis for this conclusion did not consider the additional relay failures identified in Information Notice 88-14. The section of the Information Notice addressing HFA relays was erroneously evaluated as not applying to relays installed in the plant.

HFA relays installed during 12R outage were refurbished by the vendor prior to installation in the plant and are not affected by this potential defect.

As of the end of this reporting period, the licensee was identifying potentially affected HFA relays in safety related applications and reevaluating the required corrective actions. Based on the history of HFA relay operation at the plant and the existing surveillance program, an immediate safety concern does not exist. This item will remain unresolved pending completion of the evaluation. (50-219/89-21-02)

8.0 Open (UNR 89-21-04) Missed Containment Spray System Surveillance Test

On 10/2/89, the licensee identified that a surveillance test on the containment spray system, 607.3.002, "Automatic Initiation of the Containment Spray System," had not been performed. The last date for the surveillance test was 9/30/89. In response the licensee initiated performance of the surveillance and satisfactorily completed it on 10/2/89. A review was initiated to identify the causes for missing the surveillance test.

Inspectors reviewed the circumstances surrounding this missed surveillance test. This test had been identified on the weekly surveillance printout. It was concluded the reason the test was not performed was faulty implementation of the I & C work load for the week. In addition, no feedback mechanism was provided to assure required tests were completed. Contributing to this was that the I & C shop had only one supervisor. He was coordinating work for the whole shop and had failed to identify this test for performance.

The licensee has taken steps to improve the scheduling and review of surveillance test completion. These include: the use of a monthly surveillance test status board in the I & C shop and the requirement that surveillance tests be addressed in the Plan of the Day meeting. In addition, the licensee is considering the use of an integrated schedule. This integrated schedule would provide a two week look ahead and actually schedule surveillance tests and manpower.

Subsequent licensee recalculation of the last date showed the date to be 10/4/89. The date moved based on adding the amount of time the plant was shut down in September to the 3.25 x (surveillance interval) requirement. The rationale is the time the system is not required to be operable does not add to the 3.25 requirement. This methodology allows the 3.25 requirement for three consecutive tests to be met even over long outages. The 1.25 requirement remains unchanged.

Since the containment spray system was considered operable during the shutdown period, the technical basis for adding the days shut down is not obvious. This methodolgoy could allow an effective lengthening of surveillance intervals. The licensee methodology for calculating surveillance test dates will be unresolved pending NRC review. (50-219/UNR/89-21-04)

9.0 Closed (NCV 89-21-05) No Senior Licensed Operator in the Control Room

On 9/27/89 there was no licensed senior reactor operator (SRO) in the control room for six minutes. The two SROs on shift are the Group Shift Supervisor (GSS) and the Group Operating supervisor (GOS). Technical specifications require at least one licensed SRO in the control room except when the reactor is in the cold shutdown or refueling modes.

Poor communications resulted in this event. The Group Shift Supervisor (GSS) had left the control room to perform some administrative duties in the computer room (located next to the control room). Although the GOS was in the control room at the time, the GSS failed to inform him that he was leaving the control room. While the GSS was in the computer room, the GOS left the control room to investigate an equipment problem in the reactor building. The GOS did not realize that the GSS was in the computer room. The GOS realized that the GSS was not in the control room when the GOS attempted to contact the GSS from the reactor building.

The individuals involved recognized that technical specifications were violated and wrote a deviation report to address the event. The security computer printout indicated the length of time in which no SRO was in the control room was approximately six minutes. A memorandum was issued to all SROs from a plant operations manager requiring face to face communications between SROs when leaving the control room. The licensee concluded that this event was caused by personnel error and an isolated event.

Technical specifications require a licensed senior reactor operator in the control room at all times except when the reactor is in the cold shutdown or refueling modes. The failure to have a licensed senior reactor operator in the control room during plant operations is a violation. This violation is not being cited because:

- The event was licensee identified.
- The event will be reported in a Licensee Event Report.
- The safety significance was minor.
- The licensee response was prompt and effective.

- The event could not reasonably have been prevented by corrective actions to a previous violation.

The inspector concluded that the individuals involved demonstrated a high level of professionalism in reporting this event. (NCV89-21-05)

10.0 Control Rod Drive Motor Breaker Failure

In March 1989, the "B" control rod drive (CRD) pump breaker failed while performing preventative maintenance. The breaker clevis pin clip had fallen off and the clevis pin slipped out. Some gnawing was observed on the end of the clevis pin where the clip was attached. This condition rendered the breaker inoperable.

In response to this failure, several actions were taken. The "B" CRD breaker was replaced. A short form was generated on 3/10/89 to investigate the failure of the CRD motor breaker. On 8/17/89, a short form was written to inspect seven similar breakers. In September, four of the seven breakers were inspected. No abnormalities were identified in the inspections.

The vendor was consulted on this failure. The "B" CRD breaker was a General Electric breaker, type AKS-50. The initial vendor response was that the failure was isolated and recommended a kit to modify the breakers. Because the modification kit was not a guaranteed fix by the vendor, the licensee decided to send the breaker to the vendor to determine the root cause and to effect a permanent repair.

The inspector became aware of the CRD breaker failure on 9/12/89 when the breaker was observed in the electrical maintenance shop. At the time which the inspector became aware of the breaker failure, no inspections of other breakers had been performed and no deviation report or material nonconformance report was written. The inspector reviewed the Control of Nonconformance and Corrective Action Procedure, procedure 104. The procedure requires a failure like the CRD breaker failure to be documented in a deviation report. Although a different revision was in effect in March, the previous revision also required documentation of similar failures in deviation reports.

The inspector concluded that the CRD breaker failure was informally addressed for six months. This informality does not provide assurance that the appropriate level of management attention or adequate root cause determination will be given to significant events.

A deviation report was written on 9/22/89 by an electrical foreman. The electrical foreman had written the deviation after reading a memorandum issued by the site director. Based upon the licensee's corrective actions and the results of the breaker inspection, the inspector had no further questions.

11.0 Radiation Protection

11.1 Radiological Protection Observations

During periodic entry to and exit from the radiologically controlled area (RCA), the inspectors verified that proper warning signs were posted, personnel entering were wearing proper dosimetry, personnel and materials leaving were properly monitored for radioactive contamination, and monitoring instruments were functional and in calibration. Posted extended radiation work permits (RWPs) and survey status boards were reviewed to verify that they were current and accurate.

The inspectors observed activities in the RCA to verify that personnel complied with the requirements of applicable RWPs and that workers were aware of the radiological conditions in the area.

The inspectors made some observations which indicate weak radiological controls practices. The inspectors noted that an individual failed to frisk a hand held piece of equipment after exiting a contaminated area. When questioned, the individual stated that he had continuous control of the equipment while he was in the contaminated area because he did not set it down or let it touch anything. Although in this instance no contamination was picked up or spread since the item was frisked when exiting the RCA, this practice is poor. The inspectors noted suspicious looking debris in the RCA. This debris included cigarette butts, empty cigarette packages, and food wrappers. Though the licensee stated that they have on occasion seen wrappers blown through the fence into the RCA, it was noted that several cigarette butts were found in close proximity to each other.

The inspectors, however, acknowledge that the licensee has performed assessments in this area and has developed programs to address this problem.

11.2 ALARA Review for "A" Evaporator

The inspector reviewed the ALARA package for the work on the "A" evaporator. Individual exposure versus overall exposure was considered in the job planning. Many alternatives for performing the job, including the need, were considered. Senior site management was briefed prior to the performance of the work. The estimated work time and exposures correlated closely with the actual times and exposures. The job was performed without any unanticipated problems. The inspector concluded that the job was well planned and executed.

12.0 Isolation Condenser Return Valve Failure

During plant shutdown on 9/11/89, the "A" isolation condenser return valve, V-14-34, tripped on overload. By procedure, the return valves are required to be cycled every 100 degrees F change in reactor coolant temperature to prevent thermal binding. This requirement was implemented because the "B" isolation condenser return valve experienced thermal binding several times in the past.

The licensee conducted an extensive review of the cause of the overload trip. Several possibilities for the failure including torque switch failure, operator failure, hydraulic lock and potential grease in the spring pack, were considered. The licensee concluded that the failure was probably thermal binding. The licensee further concluded that this failure was an isolated incident based upon the fact that it was the first instance of thermal binding on the "A" isolation condenser return valve and the first failure since the implementation of the requirement to cycle the valves every 100 degrees F. A deviation report, however, was written in an effort to address isolation condenser valve reliability. Review of this issue by the licensee is still ongoing.

The inspector had no further question on the licensee's efforts to address the isolation condenser return valves.

13.0 Material Procured from the Meredith Corporation

In response to Information Notice 89-56, the licensee conducted a review of their procurement documents to identify any material procured from the Meredith Corporation, Pressure Vessel Nuclear (PVN). Information Notice 89-56 had identified that PVN was indicted for falsification of material certification documents.

The licensee's review identified that a 20-foot long, 2 1/2-inch diameter solid bar stock was procured from PVN. The material was used in 1987 to repair the drywell after 2 1/2-inch diameter core samples were taken. These core sample were taken in response to the drywell thinning issue. Thirteen feet of this material still remained in the licensee's warehouse.

The licensee contacted Spectrum Laboratories which performed the certification of this bar stock for PVN. The laboratory confirmed the authenticity of the certification.

A sample of the stock bar was sent to GPU Nuclear's Reading laboratory. Results from Reading confirmed that all specifications except one were met. Material hardness was low out of specification. The licensee evaluated the material hardness and concluded it was acceptable for use in its present application.

The inspector concluded that the licensee's response to the information notice and to the identification of the PVN material was appropriate. The licensee's resolution of the out of specification material hardness was reasonable. The inspector had no further questions.

14.0 Maintenance Observation

14.1 Feedwater Check Valve

On 9/11/89, the licensee inspected and discovered a one gallon per minute leak on the valve cover of the feedwater check valve, V-2-72. The inspection of the feedwater check valve was performed in response to the reactor water level transient event which occurred on 9/7/89. Details of this transient are described in paragraph 3.0.

The licensee attempted to stop the leak by increasing the torque on the valve cover bolts. Valve leakage decreased; however, after the shutdown on 9/11/89, the decision to repair the valve was made. The licensee discovered two indications on the pressure o-ring seal and one on the valve body seating surface. With the concurrence of the vendor, the pressure O-ring was replaced and the valve body area hand buffed. The valve successfully passed its post maintenance testing and local leak rate test.

The inspector observed portions of the maintenance on the feedwater check valve. The radiation work permit and the work package were reviewed. The inspector noted that after the maintenance workers made their first entry into the trunnion room to torque the valve cover bolts, the maintenance had to be suspended because the proper tool was not available. The tool was fabricated and personnel reentered the trunion room to torque the valve.

The feedwater check valves were worked on during the last refueling outage. During that time, a special tool had to be fabricated to torque the bolts. The work procedure, however, did not capture the requirement for a special tool. The licensee stated that a new initiative was started in December 1987 to include an additional work feedback sheet in maintenance procedures. Because the maintenance procedure did not include this feedback sheet the last time the valve was worked the requirement for the special tool was not captured. The licensee stated that approximately one in five feedback sheets used are being sent back and concluded the program thus far is successful. The inspector had no further questions.

14.2 "B" Fuel Pool Heat Exchanger

The licensee identified a low flow noise in the "B" Fuel Pool Heat Exchanger. Maintenance work was initiated to determine the cause of the abnormality and repair it. When the heat exchanger tube bundle was removed, a loose tube was discovered. The tube was shimmed and the flow noise disappeared.

The inspector observed portions of maintenance performed on the heat exchanger. The radiological work permit and the work package were reviewed. The inspector observed the system valved out of service and danger tagged. Temporary variations and danger tag out logs were reviewed. The inspector noted that the radiological controls support for the work was good. A radiological controls technician was present at the work site throughout the maintenance. The inspector had no further questions on the maintenance.

15.0 Surveillance Observation

Portions of the surveillances listed below were observed during this inspection period. The inspectors verified required administrative approvals were obtained, data results met the acceptance criteria, procedures met technical specification requirements and procedures were appropriately adhered to by the operators. The inspectors had no questions on the performance of the surveillances.

- Fuel zone level channels "C" and "D": Ancillary Components Calibration and Test, Procedure 664.3.006

- Reactor Lo Lo Level Function Test, Procedure 619.3.004

16.0 Engineered Safeguards Feature System Walkdown

A system walkdown on the Standby Liquid Control System was conducted on 10/4/89. Valve lineup, equipment power supply, system equipment conditions, area housekeeping, labelling of the equipment and control room indications were verified. No unacceptable conditions were identified.

17.0 Observation of Physical Security

During daily tours, the inspectors verified that access controls were in accordance with the Security Plan, security posts were properly manned, protected area gates were locked or guarded and that isolation zones were free of obstructions. The inspectors examined vital area access points to verify that they were properly locked or guarded and that access control was in accordance with the security plan.

18.0 Previously Opened Items

(Closed) Temporary Instruction 2515/96

SIMS Item (MPA-D-20): Mark I BWR Drywell Vacuum Breaker Modifications

In December 1979 General Electric issued SIL No. 321 informing customers of unanticipated cycling of and damage to drywell vacuum breakers during LOCA tests in a prototype Mark I containment. To assure that drywell vacuum breakers would be capable of withstanding oscillating loads from chugging and condensation, the staff issued Generic Letter 83-08 requesting licensees of Mark I containments to perform plant unique calculations to determine the structural adequacy of the drywell vacuum breakers. In response to the Generic Letter, GPU Nuclear (the licensee) in letters dated August 14, 1985, and May 23 and December 3, 1986, submitted the results of their evaluation. In the three responses the licensee identified the counterweight arms, disc arms, disc arm keys, valve shaft, counterweight hubs and counterweight arm hub keys to be replaced. The licensee proposed to replace these parts with parts made of higher strength material.

The staff, in a Safety Evaluation dated March 3, 1987, concluded that the action proposed by the licensee to restore the original design margin of safety under the revised loadings is acceptable.

On March 31, 1988, the NRC issued Temporary Instruction 2515/96 to verify that plants have modified their drywell vacuum breakers in response to Generic Letter 83-08.

The licensee's structural evaluation of the torus to drywell vacuum breakers was performed by MPR Associates, Inc. and was documented in MPR Report MPR-1096 dated October 1988. The evaluation was based upon the valve configuration and component material documented in Table 2-1 of the report. The licensee also prepared document MDD-OC-243-A "Modification Design Description for Mark I Containment - Torus to Drywell Vacuum Breakers." This document describes the Oyster Creek Nuclear Generating Station torus to drywell vacuum breaker replacement part requirements to meet NRC Mark I containment program acceptable stress criteria. In addition to reviewing the above document, the inspector also reviewed the appropriate purchase orders for the replacement items, certificates of compliance, spare parts lists and the Job Completion Package V-26-0001.

Based on the review of the above information, the inspector has concluded that the licensee has replaced the counterweight arms, disc arms, disc arm keys, valve shaft, counterweight hubs and counterweight arm hub keys with higher strength materials as specified in MPR Report MPR-1096 dated October 1988. This is in accordance with NRR requirements specified in the staff's SE dated March 3, 1987. Therefore, this item is considered closed.

(Closed) Violation 86-24-02. This violation resulted from the licensee changing the plant procedures to require isolation of the isolation condensers upon a reactor water level at or above 180 inches without a written safety evaluation. It was also noted in the violation that plant technical specifications require the isolation condenser system to be operable whenever the reactor coolant temperature is above 212 degrees F. During plant cooldown isolation condensers are used to remove decay heat. However, before the shutdown cooling system is placed into service with no reactor recirculation pumps running, reactor water level is required to be raised to ensure adequate core circulation.

In response to the violation the licensee indicated that administrative and plant procedures on the safety review process were revised to address the recognized weakness in the process. Also, a written safety evaluation was prepared for the procedural changes identified in the violation.

The subject safety evaluation utilized the Safety/Environmental Determination and 50.59 Review Form completed on 10/29/86. The written safety evaluation is brief and does not address the technical specification requirement of operable isolation condenser system above 212 degrees F. reactor temperature. The licensee concluded that adding clarifying notes in the technical specification regarding the operability requirement of the isolation condensers could be confusing to the operators. The safety significance of this compliance issue is minimal, as adequate core cooling is maintained.

The inspector reviewed the revised administrative and plant procedures which govern the safety review process, and several safety evaluations that were done to support certain procedure changes. In general, the safety review process has improved; however, the 50.59 criteria are not always consistently addressed. Licensee's safety review process is periodically assessed by the NRC. Based on the improvements observed and periodic NRC review, this item is closed.

(Closed) Inspector Follow Item 86-42-01. Following a reactor scram and subsequent cooldown on June 12, 1985, the licensee completed a Transient Assessment Report TAR-OC-0008 which recommended changes to plant cooldown procedures and improvements in the scram discharge volume (SDV) vent and drain valve testing requirements.

Procedure 305, "Shutdown Cooling System Operation" requires reactor level to be maintained greater than 185 inches above the top of the active fuel (TAF) when all reactor recirculation pumps are secured and the Shutdown Cooling System is in operation. However, with reactor level above 185 inches (TAF) the reactor dome cannot be vented to the isolation condensers preventing cooldown using the isolation condensers. The licensee revised procedure 305 and 301, "Nuclear Steam Supply System" to require reactor water level to be less than the 185 inches TAF limit when the isolation condenser is used for cooldown. The inspector reviewed procedures 301 and 305, and concluded that the revisions were adequate.

The recommendations for improvements in the SDV valve testing requirements will be followed under unresolved item 85-23-06.

The inspector had no further questions. This item is closed.

(Closed) Notice of Violation 86-37-03. Several discrepancies in as-built drawings of safety related electrical power system panels were identified. In a letter dated March 16, 1987, the licensee acknowledged the problems identified in part A of the violation however questioned the problems identified in part B of the violation since the equipment involved had not been turned over to operations by maintenance. As corrective actions, the licensee reviewed the functional devices on the 125 VDC Distribution Center C and conducted inspections of two additional electrical panels to verify the accuracy of the as-built drawings. The licensee identified some additional errors on the as-built drawings which were corrected through the drawing control program by use of field change requests.

The inspector concluded that the accuracy of the as-built drawings has not adversely affected the operation of the facility and that identified errors have been corrected. The inspector had no further questions. This violation is closed.

(Closed) Notice of Violation 87-08-01. The technical specification surveillance procedures for channel calibration of the primary containment floor drain sump and equipment drain tank flow integrators were not incorporated into the 600 series of procedures. The inspector reviewed the new surveillance procedures in the 600 series for the calibration of the integrators and concluded that the procedures were adequate for completion of the technical specification surveillance requirements. The inspector had no further questions. This violation is closed.

(Closed) Inspector Follow Item 87-11-06. The size of the air sample volume collected in the plume of an accident release was also identified as an issue under open item No. 88-06-05. This was closed in NRC Inspection Report No. 88-30 based on the licensee's commitment to evaluate the procedure for collecting air samples. This item is closed based on inspection conclusions in NRC Inspection Report No. 88-30.

(Closed) Notice of Violation 87-13-01. The technical specification surveillance calibrations of the reactor pressure and water level instruments on the remote shutdown panel were not conducted. The inspector reviewed completed copies of several surveillance procedures for calibrations of remote shutdown panel instruments and verified the existence of 600 series procedures for calibration of all remote shutdown panel instrumentation required by technical specifications. The inspector determined that all required procedures existed and that the calibrations were conducted at the proper frequency. The inspector had no further questions. This violation is closed.

(Closed) Notice of Violation 87-13-03. The licensee submitted annual reports of plant modifications as required by 10CFR50.59 for the years 1983 through 1986, from 39 months to ten months after the end of the calendar year. The licensee's response to the violation which is contained in a letter dated September 4, 1987, indicated that ten months met the annual submittal requirement and committed to submit all future reports within seven months after the end of each calendar year.

The inspector reviewed annual reports for 1987 and 1988, and determined that the annual reports were issued within seven months of the end of the reporting period. This violation is closed.

(Closed) Notice of Violation 88-33-02. This violation was issued for failure to report a safeguards event. As documented in NRC Region I letter to GPU Nuclear dated 5/15/89, the circumstances of the event were reconsidered. Based upon the licensee's deliberation of reportability at the time of the event, the violation was retracted. This item is closed based on withdrawal of the violation.

(Open) Notices of Violation 87-16-01, 87-16-02, and 87-16-03. On April 27, 1987, containment vacuum breakers were incorrectly blocked open. The corrective actions taken and planned by the licensee were presented in a meeting with the NRC on May 11, 1987, and are documented in NRC Region I Meeting Report No. 87-18. Inspections of the completed corrective actions conducted subsequent to the meeting are documented in NRC Inspection Report No. 87-13, and determined that the short term corrective actions were acceptable. Planned long term corrective actions included resolving problems with the temporary variation program which were identified in Quality Deficiency Report 87-009 and conducting an incident investigation team review using techniques of the Management Oversight and Risk Tree (MORT) process.

The inspector reviewed Quality Assurance Report 8712017J completed in December 1987 which documents the licensee's review and audit of the temporary variation program. Few deficiencies were noted by the licensee and the report concluded that the program for controlling temporary variations was adequate. The inspector reviewed the temporary variation log and selected 50.59 review sheets and concluded that administratively, temporary verifications are adequately controlled.

The inspector reviewed the Independent Onsite Safety Review Group Final Report issued on August 7, 1987. The report identified the root cause of the event "to be personnel error in the failing to properly evaluate the nuclear safety implications of the intended actions." The report delineated numerous recommendations in several areas. These violations remain open pending the inspector's review of the acceptability of the disposition of the report recommendations.

(Open) Unresolved Item 89-04-02. This item was originally opened pending the results of the environmental qualification of the two breakers associated with valves V-37-11 and V-5-166, and review of licensee's completed corrective action on the engineering component data base.

In order to establish operability of the subject components the licensee has performed a material analysis to establish similarity with qualified breakers. The licensee did not address the effect of radiation on the breaker materials in question. The licensee is currently addressing inspectors' questions on radiation qualification and some material differences. This item remains open.

19.0 Inspection Hours Summary

Inspection consisted of 261 direct inspection hours out of a total of 523 inspector hours on site. Sixty-five of these direct inspection hours were performed during backshift periods, and 25 of the backshift hours were performed during deep backshift periods.

20.0 Exit Interview and Unresolved Items

A summary of the results of the inspection activities performed during this report period was made in a meeting with senior licensee management at the end of this inspection. The licensee stated that, of the subjects discussed at the exit interview, no proprietary information was included.

Unresolved items are matters for which more information is required in order to ascertain whether they are acceptable, violations, or deviations. Unresolved items are discussed in paragraphs 6.0, 7.0 and 8.0 of this report.