U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	99-07
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License No.	DPR-16
Licensee:	GPU Nuclear Incorporated 1 Upper Pond Road Parsippany, New Jersey 07054
Facility Name:	Oyster Creek Nuclear Generating Station
Location:	Forked River, New Jersey
Inspection Period:	August 16, 1999 - September 26, 1999
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EXECUTIVE SUMMARY

Oyster Creek Nuclear Generating Station
Report No. 99-07

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers about a six-week period of inspection.

Plant Operations

- Operations management demonstrated a safety-focused questioning attitude in challenging the Plant Review Group's operability determination concerning a 34.5KV offsite power source. This item remains unresolved pending NRC review of the licensee's resolution of the operability and reportability aspects of this issue. (Section O2.1)

- Operations took appropriate actions in preparation for Hurricane Floyd and effectively implemented their high winds procedure. (Section O2.2)

- An operator error resulted in a momentary unavailability of a core spray pump. The operator's failure to position the proper switch in accordance with Procedure 108, *Equipment Control*, Section 10.3, is a violation of TS 6.8.1, which requires that written procedures shall be established, implemented and maintained. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. Operations documented this issue in CAP 1999-1227. (Section O4.1)

- Operators did not comply with administrative and independent verification requirements as required by Procedure 108, *Equipment Control*. This is a violation of TS 6.8.1, which requires that written procedures shall be established, implemented and maintained. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. Operations documented this issue in CAP 1999-1257. (Section O4.2)

- Reactor building equipment operators did not consistently demonstrate good radiological work practices to question a radiological posting change in the shutdown cooling pump room. (Section R1.2)

Maintenance

- Site Services provided operations support through their timely and comprehensive actions to secure loose equipment and materials on site and prepare the site for high winds. (Section O2.2)

- Maintenance technicians demonstrated poor work practices during a surveillance test. A lead maintenance technician provided a good self-assessment of the poor work practices to his supervisor. (Section M4.1)

- A Quality Verification specialist demonstrated attention to detail and determination to document deficiencies with a maintenance activity to repack isolation condenser vent valves. (Section M7.1)

Engineering

- Engineering demonstrated design basis awareness and a questioning attitude in identifying a potential operability concern involving a 34.5KV offsite power source. (Section O2.1)

- Engineering conducted prompt and appropriate evaluations to support continued emergency diesel generator operability in response to recurring start failures in the non-emergency mode during surveillance testing. (Section E2.1)

- A system engineer performed a good extent of condition and root cause evaluation to determine the cause of multiple reactor building closed-loop cooling water pump breaker trips. (Section E2.2)

- Although the inspector determined that a fault at one electromatic relief valve (EMRV), or on the associated wiring, would not prevent the other EMRVs from operating, the oversight by the licensee of not addressing short circuit and fuse-breaker coordination following the cable addition indicated insufficient attention to detail during the modification process. (Section E2.3)

- The justifications provided by the licensee for the removal from the EQ program of the solenoid valves associated with the isolation condenser vent valves were reasonable and acceptably addressed the NRC concerns regarding the solenoid's ability to perform their safety function when required. (Section E2.4)

Plant Support

- Radiological controls technicians did not effectively communicate changing radiological conditions in the shutdown cooling pump room to equipment operators. (Section R1.2)

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Report Details

Summary of Plant Status

Operators maintained the unit at or near full power for the duration of the period.

I. OPERATIONS

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant activities and operations, using the guidance in NRC inspection procedure 71707. The inspectors conducted routine plant tours to assess equipment conditions, indications of operator work-arounds, procedural adherence, and compliance with regulatory requirements.

Operators conducted control room activities in a professional manner with staffing levels above those required by technical specifications (TS). The inspectors verified operator knowledge of ongoing plant activities, the reason for any lit annunciators, and the adequacy of existing fire watches. The inspectors also routinely performed independent verification of safety system status, from the control room indications and in the plant observation of equipment operation/position, for the plant operational mode.

O2 Operational Status of Facilities and Equipment

O2.1 Offsite Power Source Availability

a. Inspection Scope (71707, 37551)

The inspector routinely reviewed corrective action process (CAP) reports and assessed the licensee's identification and preliminary resolution of CAP 1999-0877.

b. Observations and Findings

While evaluating a minor offsite power electrical transient, engineering identified a potential operability concern involving one of two redundant TS-required 34.5KV offsite power sources. Technical Specification 3.7.A.3 requires one 230KV line and one 34.5KV line to be fully operational. Engineering noted that Updated Final Safety Analysis Report (UFSAR) Section 8.2.1.2 states that the Z52 34.5KV line "delivers power to OCNGS and provides an interconnection with the 34.5KV General Public Utilities Energy (GPUE) transmission system at the Manitou substation". The Z52 line is normally configured with an open load break switch at Pinewald. Under normal conditions the 34.5KV Z52 line can not provide power to OCNGS without GPUE actions to close the Pinewald load break switch. The Q121 line (the redundant 34.5KV OCNGS power source) is similarly described in the UFSAR, but does not have a normally open load break switch.

When in service, the Q121 line satisfies the TS requirement. Engineering questioned the operability of the Z52 line and reportability (operation outside the design basis), especially during periods when GPUE removed the Q121 line for maintenance. On July 15, 1999, engineering initiated CAP 1999-0877 to evaluate this condition.

On July 20, the plant review group (PRG) conducted PRG meeting 99-18 to evaluate the condition. The PRG concluded that the condition was not reportable and that all TS operability requirements were met, provided that GPUE has the capability to establish Z52 as an "express feeder" into Oyster Creek within 30 minutes, if needed. The PRG also directed additional corrective action to clarify the UFSAR design description and change TS 3.7 as necessary. Following PRG's decision, the Operations Director reviewed PRG's conclusion, and challenged it based on his understanding of Oyster Creek Technical Specifications and review of the Facility Description and Safety Analysis Report (FDSAR). He believed that even though the TS wording is not completely clear, the intent was to have power from either the Q121 or Z52 line available to the startup transformers whenever the reactor was critical. The Operations Director questioned whether operators should enter a seven day TS limiting condition for operation (LCO) whenever the Q121 was out of service (unless the load break switch on the Z52 line was closed).

Near the end of the inspection period, the inspector reviewed the preliminary resolution of CAP-1999-0877 (as discussed above) and noted that with Q121 out of service, and the Z52 load break switch open, the appropriate TS 3.7.B action appeared to be for operators to place the unit in the cold shutdown condition. The inspector discussed this observation with the Operations Director and he concurred (on the basis of considering the Z52 line inoperable with the load break switch open). The Operations Director stated that he would expedite the resolution of this issue. The inspector also discussed with senior management the importance of a timely resolution of the issue (Z52 line operability) based on the risk associated with loss of offsite power (32.8 percent contributor to core damage frequency) and the fact that line Z52 is relied upon whenever Q121 is taken out of service. Oyster Creek procedure 2000-ADM-1220.01, *Implementation of the Maintenance Rule,* Exhibit 1 lists the 34.5KV bus and lines as risk significant. This item remains unresolved pending NRC review of the licensee's resolution of the operability and reportability aspects of this issue. **(URI 50-219/99-07-01)**

c. Conclusions

Engineering demonstrated design basis awareness and a questioning attitude in identifying a potential operability concern involving a 34.5KV offsite power source. Operations management demonstrated a safety-focused questioning attitude in challenging the plant review group's operability determination. This item remains unresolved pending NRC review of the licensee's resolution of the operability and reportability aspects of this issue.

O2.2 Hurricane Floyd Response

a. Inspection Scope (71707)

The inspector evaluated the licensee's preparations for Hurricane Floyd. As the storm approached, the inspector provided continuous site coverage to assess the operational status of the Oyster Creek Nuclear Generating Station.

b. Observations and Findings

During the week of September 13, operations received weather forecasts indicating that Hurricane Floyd may impact the New Jersey coast within several days. Although they did not meet any of procedure 2000-ABN-3200.31, *High Winds*, entry conditions, operations proactively implemented applicable portions of their high winds plant readiness check-off sheet in preparation for the storm. In particular, Site Services maintenance technicians led the licensee's efforts to secure all outdoor loose equipment and materials, sandbag selected areas, and top-off tanks as needed. Based on protected area tours, the inspector determined that Site Services effectively readied the site for high winds.

On the morning of September 16, the Oyster Creek Environmental Affairs Meteorologist informed operations that the National Weather Service issued a Hurricane Warning for the Jersey coast up through Manasquan Inlet. The meteorologist projected strong winds late in the day, with sustained 40-50 mph winds and potential gusts upward of 60-70 mph. In addition, the storm surge had the potential to cause higher than normal intake water levels. At 5:52 a.m. on September 16, operators appropriately entered their high winds procedure due to the hurricane warning. Based on frequent plant tours on September 16, the inspector observed that operators effectively implemented their high winds procedure. Operators conducted increased monitoring of the intake levels and remained aware of emergency action levels relative to emergency classification in accordance with procedure EPIP-OC-.01, *Classification of Emergency Conditions*. The Oyster Creek meteorologist kept operators well informed of the hurricane's status throughout the day.

At 5:00 p.m. on September 16, the National Weather Service downgraded Floyd to a tropical storm. At approximately 6:28 p.m., the storm passed 10 miles to the east of the plant. Operators recorded their highest observed intake level at 2.8 feet (4.5 feet triggers a plant shutdown) at 6:11 p.m. Operators recorded the maximum 33-foot elevation 15-minute wind gust at 40 mph at 4:15 p.m. Operators exited their high winds procedure at 4:49 a.m. on September 17. The site sustained no storm-related damage or adverse impact.

c. Conclusions

Site Services provided operations support through their timely and comprehensive actions to secure loose equipment and materials on site and prepare the site for high

winds. Operations took appropriate actions in preparation for Hurricane Floyd and effectively implemented their high winds procedure.

O4 Operator Knowledge and Performance

O4.1 Core Spray System 69 Permissive Inadvertent Operation

a. Inspection Scope (71707)

On September 23, an operator mistakenly opened the 69 permissive switch for the 'C' core spray pump breaker while preparing to hang an outage tag on the emergency service water (ESW) 52C pump breaker. The inspector reviewed the operations personnel on shift actions, reviewed outage tagging procedures, and interviewed operations personnel. NRC Inspection Report 50-219/ 99-05 (Section O4.1) documented a similar occurrence of operators inadvertently operating the wrong component (NCV 50-219/ 99-05-01).

b. Observations and Findings

On September 23, at approximately 3:06 a.m., operators were hanging an outage (tagout) on ESW system 2 in preparation for planned maintenance. The operator performing the outage initially positioned himself in front of the ESW 52C pump breaker. The operator turned around to put down the items that he was carrying. When he turned back around, he was in front of the 'C' core spray pump breaker (NZO1C), which was adjacent to the ESW 52C pump breaker (P-3-3C). He then mistakenly tripped the 'C' core spray pump breaker 69 permissive. The operator immediately recognized his mistake and returned the core spray pump 69 permissive to its normal position. The 'C' core spray pump 69 permissive trip switch was open for approximately 36 seconds. The operator stated that he had been to a pre-job brief, the switching and tagging order was in his possession, that he was not fatigued, and there were no distractions. The operator stated that he had disoriented himself upon turning back around from the intended breaker after putting down his equipment. He felt that he did not perform a proper self-check after turning around and zeroed in on the letter 'C' on the identification tag on the breaker cubicle, instead of the comparing the complete nomenclature.

The inspector determined that the mis-positioned trip switch did not have an actual safety consequence due to the fact that the 'D' core spray pump and the other core spray train were available; however, as an unacceptable safety system mispositioning it has more than minor safety significance. The operator's failure to position the proper switch in accordance with Procedure 108, *Equipment Control*, Section 10.3, is a violation of TS 6.8.1, which requires that written procedures shall be established, implemented and maintained. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. Operations documented this issue in CAP 1999-1227. **(NCV 50-219/99-07-02)**

The control room Group Operating Supervisor (GOS) appropriately recognized that the plant was in a TS LCO 3.4.A.4.b due to the fact that maximum average planar linear heat

generation rate (MAPLHGR) was greater than 90 percent. With a core spray pump out of service, TS require MAPLHGR to be less than 90 percent. Operators documented this event at CAP 1999-1227. At the end of the inspection period, GPUN personnel continued to review the event to determine the root cause and corrective actions. This event is similar to an event which occurred on July 29, 1999, when an operator error resulted in a momentary isolation of emergency service water system 2 with the redundant system out of service for maintenance. At the time of the September 23rd core spray pump breaker 69 permissive mispositioning, operations had not yet implemented all of the corrective actions in response to the July 29 event. The Operations Director stated that he would hasten the corrective actions from this event, since the two incidents were very similar.

c. Conclusions

An operator error resulted in a momentary unavailability of a core spray pump. The operator's failure to position the proper switch in accordance with Procedure 108, *Equipment Control*, Section 10.3 is a violation of TS 6.8.1, which requires that written procedures shall be established, implemented and maintained. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. Operations documented this issue in CAP 1999-1227.

O4.2 Equipment Control Procedure Non-compliance

a. Inspection Scope (71707)

The inspector reviewed outage tagging procedure, Procedure 108, *Equipment Control,* and interviewed operations personnel concerning tagging operations during the review of the 'C' core spray pump 69 permissive inadvertent operation (see Section O4.1 of this report).

b. Observations and Findings

During the walkdown of the breaker cubicles associated with the core spray 69 permissive inadvertent operation, the inspector noticed that the operator had annotated the outage tag (99-0881) on the 52C ESW pump with a time of '0230' (2:30 a.m.), on September 23, 1999. The inspector questioned this time since the 'C' core spray pump breaker inadvertent operation occurred at 3:06 a.m. and the ESW 52C breaker was not operated until later in the morning after the core spray breaker was returned to its normal configuration The inspector interviewed operations personnel to evaluate tagging practices.

Operations personnel stated that sometimes they date and time several tags in advance so that the annotated time correlates to the time the switching and tagging order indicates that it was executed. This is contrary to Procedure 108, section 10.3.3, which requires that operators, "sign and date each tag on the appropriate line as it is hung." During a different tagging evolution, the inspector observed an operator posting a tag which also had been previously dated and timed.

When operators hung the tag on the 52C ESW pump breaker, after the previously mentioned mispositioning (section O4.1), the operator that was used to 'peer check' the proper operation of the 52C ESW pump breaker 69 permissive, was also used to independently verify the switching component position and tag. This is contrary to Procedure 108, section 3.8, which states that "Independent Verification is a check of a condition conducted by a qualified individual who was not involved in establishing the condition or position." Operations personnel should have obtained an additional person to independently verify the component position who was not involved in the peer checking of the breaker's positioning.

Additionally, operations personnel told the inspector that because of safety requirements when racking out a 4160V breaker, they also were not able to comply with Procedure 108 independent verification requirements. The inspector determined that a similar situation existed during tagging operations in the torus room.

These three instances of non-compliance with Procedure 108, *Equipment Control*, did not have an actual safety consequence, but has more than minor significance as an unacceptable application of the safety tagging procedure. This procedural non-compliance also did not appear to contribute to the inadvertent operation of the 'C' core spray pump breaker 69 permissive. However, this is a violation of TS 6.8.1, which requires that written procedures shall be established, implemented and maintained. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. Operations documented this issue in CAP 1999-1257. **(NCV 50-219/99-07-03)**

c. Conclusions

Operators did not comply with administrative and independent verification requirements as required by Procedure 108, *Equipment Control*. This is a violation of TS 6.8.1, which requires that written procedures shall be established, implemented and maintained. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. Operations documented this issue in CAP 1999-1257.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 Maintenance Activities (62707)

The inspectors observed selected maintenance activities on risk significant safety-related and non safety-related equipment to ascertain that the licensee conducted these activities in accordance with approved procedures, TS, and appropriate industrial codes and standards. The inspectors observed all or portions of the following job orders (JO):

- JO 535759 ESW Pumps 52C and 52D Check Valve Replacement
- JO 533606 Inspection of Standby Gas Treatment System Exhaust Fan EF-1-9
- JO 534428 Hydraulic Control Unit Repair
- JO 535228 Repair Skimmer Surge Tanks A/B Isolation Valve
- JO 535346 Replace Resistor for A/B Static Charger
- JO 515134 Relocate Feedwater Sensing Lines
- JO 532433 HFA Relay Inspection

Maintenance personnel obtained approval for work and conducted activities in accordance with approved JOs and applicable technical manuals and instructions. Personnel were knowledgeable of the activities and observed appropriate safety precautions and radiological practices.

M1.2 Surveillance Activities (61726)

The inspectors performed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. They verified that the surveillance tests were performed in accordance with TS, approved procedures, and NRC regulations. The inspectors reviewed all or portions of the following surveillance tests:

- 619.3.001 Turbine Load Rejection Scram Test
- 625.4.002 Main Turbine Valve Testing
- 607.3.002 Containment Spray/ESW System 2 Testing
- 651.4.001 Standby Gas Treatment System Test - System I
- 636.4.003 Diesel Generator Load Test
- 617.4.002 CRD Exercise and Flow Test and IST Cooling Water Header Check
- 602.4.011 Thermocouple Valve Monitoring System Channel Check
- 604.4.016 Torus to Drywell Vacuum Breaker Operability and In-Service Test

Personnel used the appropriate procedure, obtained prior approval, and completed applicable surveillance testing prerequisites. Personnel used properly calibrated test

instrumentation, observed good radiological practices, and properly documented test results to ensure that equipment met TS requirements. Qualified technicians conducted the tests and appeared knowledgeable about the test procedure.

M4 Maintenance Staff Knowledge and Performance

M4.1 Scram Discharge Instrumentation Volume Surveillance Test

a. Inspection Scope (62707, 61726, 71750)

The inspector observed maintenance technicians performing a portion of surveillance test (ST) 619.3.011, *Scram Discharge Instrument Volume Calibration and Test*, on September 2, 1999.

b. Observations and Findings

The inspector assessed that no steps were missed or performed out of sequence. The inspector reviewed the ST and did not identify any deficiencies. The inspector observed that one technician demonstrated poor radiological control practices by wiping his brow with the sleeve of his anti-contamination (anti-c) clothing. The acting supervisor informed the inspector that the lead maintenance technician self-assessed the job and noted this problem.

c. Conclusions

Maintenance technicians demonstrated poor work practices during a surveillance test. A lead maintenance technician provided a good self-assessment of the poor work practices to his supervisor.

M7 Quality Assurance in Maintenance Activities

M7.1 Quality Verification of Isolation Condenser Vent Valves Maintenance

a. Inspection Scope (62707)

The inspector reviewed maintenance JOs 535877 and 535006 that planning personnel issued to repack the isolation condenser vent valves, (V-14-005 and V-14-0020). The inspector noted that the vent valves continued to leak following repacking on July 14, 1999 (see NRC Inspection Report 50-219/99-05, Section M2.1).

b. Observations and Findings

The inspector reviewed JO 535006 to determine if maintenance work practices were related to the continuing leakage from the vent valves. During his review, he discovered that a quality verification (QV) specialist was pursuing a similar issue. The QV specialist identified that JO 535877 documented that the vent valve packing leakage was not completely stopped. The QV specialist demonstrated attention to detail to identify

deficiencies in the JO and a previous CAP (1999-1079) that did not accurately document the condition. The QV specialist also showed determination in communicating with other GPUN personnel to identify the problems and initiated CAP 1999-1229.

c. Conclusions

A QV specialist demonstrated attention to detail and determination to document deficiencies with a maintenance activity to repack isolation condenser vent valves.

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment

E2.1 Emergency Diesel Generator Starting Circuit Deficiency

a. Inspection Scope (71707, 37551)

During a review of the operations log and CAP reports, the inspector evaluated engineering's analysis of the recurring emergency diesel generator (EDG) start failures in the non-emergency mode during surveillance testing. The inspector reviewed engineering's root cause analysis, the EDG starting circuit electrical schematic, and the EDG sequence failure recorder traces with the system engineer. The inspectors previously discussed EDG start failures in NRC Integrated Inspection Report 50-219/98-10 Section E2.2.

b. Observations and Findings

On August 30, the No. 1 EDG failed to start during procedure 636.4.003, *Diesel Generator Load Test*. Equipment operators observed a sequence fault alarm locally at the diesel. Operators, based on previous guidance from engineering, reset the sequence fault and successfully started the EDG on the second attempt. Operators initiated CAP 1999-1126. On September 13, a similar event occurred during the biweekly surveillance of No. 1 EDG. Operators initiated CAP 1999-1180.

Following each of these occurrences, the system engineer promptly reviewed EDG sequence failure recorder traces to evaluate the condition to ensure the data fit previous assumptions and EDG operating experience. In resolution of CAP 1999-0984 (from an August 2 start failure), engineering determined that the most probable cause of the No.1 EDG sequence lockout was a failed pinion engagement attempt of one or both of the starter motor pinions and the pinion failure (PF) circuitry did not initiate a second or third attempt as designed. The PF circuit is designed to initiate a sequence failure after the third failed pinion engagement.

Engineering used a comprehensive troubleshooting action plan to evaluate the PF circuitry. Engineering determined that the circuitry did not initiate the second and third pinion engagement attempts due to a relay race in the PF circuit. The PF relay de-

energized and re-energized in 75 milliseconds which did not allow enough time for the STZ relay to dropout. Engineering developed a modification (PIMS No. H463) to change the PPR relay from a 1.5 second TDPU (time delay pickup) to a 1.5 second TDDO (time delay dropout) to allow 1.5 seconds for the STZ relay to dropout before re-energizing. Engineering planned to implement the PF circuitry modification in the near future and tracked the action via CAP 1999-0984-1.

c. Conclusions

Engineering conducted prompt and appropriate evaluations to support continued EDG operability in response to recurring start failures in the non-emergency mode during surveillance testing.

E2.2 Reactor Building Closed-Loop Cooling Water Breaker Trips

a. Inspection Scope (37551)

The inspector reviewed engineering department actions following two trips of a reactor building closed-loop cooling water (RBCCW) breaker.

b. Observations and Findings

On July 31, 1999, the 1-1 RBCCW pump breaker tripped. Maintenance technicians replaced the static time device (STD), performed undervoltage (UV) checks and placed the breaker back in service. On September 4, the breaker failed to close during a planned 1-1 RBCCW pump start. Maintenance technicians found that the UV coil was damaged and replaced it under JO 535499. On September 15, the 1-1 RBCCW pump breaker tripped while operating. Maintenance technicians determined that the UV coil was damaged and that the STD output had a higher output voltage than the coil rating. Technicians replaced both components and checked the STD output and found it to be satisfactory.

The inspector observed the removal of the UV coil from the pump breaker and discussed the condition with the system engineer. The system engineer determined that the failures of the UV trip coils on September 4, and September 15, were caused by the STD box output resistor failure which caused the STD output to rise above the UV coil voltage rating, causing the UV coils to overheat and fail. The engineer determined that the STD failure on July 31, was due to aging of an electrolytic capacitor. He identified the capacitor that failed was from the old style STD units that had been installed in the plant for 30 years and identified this as a 480V breaker system issue. The system engineer evaluated the remainder of the STD units installed in the plant and found that there were four units that were the old style. He documented his root cause evaluation and recommended that these units be replaced at the next scheduled maintenance interval (CAP 1999-1198). The system engineer also recommended revising the breaker PM to check the output of the STD to ensure appropriate voltage and checking the remainder of the installed units for abnormal voltage and current.

c. Conclusions

A system engineer performed an good extent of condition and root cause evaluation to determine the cause of multiple RBCCW pump breaker trips.

E2.3 Electromatic Relief Valve Cable Addition

a. Inspection Scope (37550)

The licensee installed a new larger cable between power panel DC-D and relay panel ER-18A to correct a potential low voltage condition at the electromatic relief valves (EMRVs). The increase in cable size resulted in a corresponding increase in the short circuit current available at the individual EMRV protection fuses, potentially altering the existing fuse-breaker coordination. The NRC previously questioned the electrical coordination between the supply breakers and the individual EMRV protection fuses during the electrical distribution system functional inspection (EDSFI), Inspection Report No. 50-219/92-80. The purpose of the inspection was to verify that proper coordination existed between the protective devices.

b. Observations and Findings

The Oyster Creek automatic depressurization system (ADS) is composed of five EMRVs. Three of the EMRVs are supplied by a dc source through a 15 A breaker and the other two by the redundant dc source through another 15 A breaker. Each EMRV is also protected by a 10 A fuse. An automatic transfer scheme allows the EMRVs to be powered from the redundant source if the primary source fails.

Three of the five ADS valves are required to mitigate a small break loss of coolant accident. Therefore, the breaker-fuse coordination must ensure that a fault downstream of the fuse does not also trip the supply breaker. Following the EDSFI, the licensee demonstrated that such coordination existed based on the size and length of the supply cables. However, since then, the addition of a #4 AWG power cable in parallel with the existing #12 AWG cable to resolve a potential low voltage condition at the EMRVs could have invalidated the licensee's earlier conclusions.

During the current review, the inspectors determined that, in developing modification package No. OC-MD-H100-001, the licensee had not specifically addressed the breaker-fuse coordination. In addition, based on a simplified power flow diagram, the inspectors noted that a fault upstream of the fuses might result in the loss of more than one EMRV. However, discussions with responsible licensee engineering personnel revealed that neither issue was a safety concern based on the following:

- The ADS control logic includes five individual automatic transfer schemes downstream of the fuses, rather than a single one at the bus level as implied by the simplified power flow diagram. The scheme involves the interconnection of the redundant buses through five sets (one for each EMRV) of normally open (NO) and normally closed (NC) contacts of the same relay connected in series.

The EMRVs are connected at a point between the two relay contacts. In this arrangement, the series connection of the NO and NC contacts prevents the transmission of a fault from one bus to the other. Therefore, a fault upstream of the fuses would not result in the tripping of the upstream breaker or the loss of more than one EMRV.

- For the same reason above, a fault between the fuses and the relay contact terminals, where the calculated available short circuit current is highest, would not propagate to both buses and, once cleared by either the fuse or the upstream breaker, would not prevent any of the EMRVs from operating as required.

- Because of the automatic transfer scheme, a fault at one EMRV, or anywhere in the wiring between the EMRV and the supply point between the two relay contacts, would result in the loss of both sources supplying that EMRV (blowing of both fuses). If the fuses are properly coordinated with the upstream breaker, the fault is isolated by the fuses and only one EMRV is affected.

As stated previously, the licensee demonstrated coordination following the EDSFI. However, the addition of the #4 cable considerably increased the short circuit current available and, hence, the probability of the breakers being affected under faulted conditions. Following the inspection, the licensee submitted time-current curves for fuse melting and clearing, and for breaker tripping. These curves showed that no overlap existed for times greater than 0.01 second. Therefore, the inspectors considered the probability of the upstream breakers being affected by a potential fault to be very small.

c. Conclusions

Although the inspector determined that a fault at one electromatic relief valve (EMRV), or on the associated wiring, would not prevent the other EMRVs from operating, the oversight by the licensee of not addressing short circuit and fuse-breaker coordination following the cable addition indicated insufficient attention to detail during the modification process.

E2.4 Environmental Qualification (EQ) of Isolation Condenser Vent Valves

a. Inspection Scope (37550)

As a result of field observations involving a steam leak in the vicinity of the solenoid valves associated with the isolation condenser vent valves, the inspectors evaluated the qualification status of the solenoid valves.

b. Observations and Findings

As previously discussed in Section M2.1 of IR 50-219/99-05, during a routine tour of the reactor building, the NRC inspectors observed an increase in the steam packing leakage from the isolation condenser vent valves (V-6-453, 454, 455, and 456). Upon closer inspection, they also noticed an increase in temperatures in the vicinity of the vent

valves, particularly near the vent valve solenoid valves. These solenoid valves control the air supply to the vent valves and permit their closure, when required, to preserve primary containment integrity. Therefore, the inspectors were concerned that prolonged exposure to high temperature might degrade the solenoid vital components and prevent the valves from closing.

Discussions with engineering and supervisory personnel indicated that they were aware of the leakage and that planning personnel had initiated JO 534130 to replace the packing. Regarding the NRC concerns, they stated that the solenoid valves were not in the EQ program. Nonetheless, on May 21, 1999, engineering initiated CAP 1999-0625 to evaluate the condition. Preliminary engineering evaluation indicated that the solenoid valves were environmentally qualifiable and operable, i.e., that their exposure to the elevated temperature, due to vent valve packing leakage, had not impaired their ability to perform their safety function.

During the current review, the inspectors evaluated the results of the CAP analysis and determined that the licensee, prior to the removal of the valves from the Master List, had considered their safety function and potential failures modes. Specifically, the licensee had determined that:

- in the event of a high energy line break outside containment, the solenoid valves would be exposed to a harsh environment, but would complete their safety function within 80 seconds.

- for an inside containment accident, the valves would be exposed only to long-term high radiation. In this case, however, the valves would receive an isolation signal within 200 seconds.

- based on their review of the applicable electrical drawings, a failure of an electrical source due to a "hot short" was not credible.

Typically, for electrical equipment exposed to a harsh environment and which is required to remain operable for only a short time following the onset of an accident, the NRC (NUREG 0588) requires that the EQ of such equipment be demonstrated for one hour beyond the operability period. Therefore, the inspectors further discussed the issue with cognizant licensee engineering personnel. The inspectors determined that the solenoid valves had been deleted from the EQ Master List in March 1986 and that the deletions and associated justifications had been accepted by the NRC in a letter dated August 8, 1986.

The inspectors considered the above justifications for deleting the valves from the EQ Master List reasonable. Nonetheless, they believed that such deletion might exempt the licensee from a periodic monitoring of the functionality/operability of the valves. However, the licensee indicated that the valve circuits were being tested on a monthly basis.

Based on the above and verification that, (1) a hot short was not reasonable and (2) the normal environment was within the capabilities of the solenoid valves, the inspector had no further concerns with this issue.

c. Conclusions

The justifications provided by the licensee for the removal from the EQ program of the solenoid valves associated with the isolation condenser vent valves were reasonable and acceptably addressed the NRC concerns regarding the solenoids ability to perform their safety function when required.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) EEI 50-219/98220-01023; Environmental Qualification of the EMRVs (92903)

During the April 1998 NRC engineering inspection, IR 98-80, the NRC found that the EQ of the five ADS EMRVs had not been demonstrated with respect to minimum operating voltage. Specifically, the NRC found that the voltage available at the EMRVs solenoid valves, following a small break loss of coolant accident, might not be sufficient to actuate the solenoids and allow opening of the EMRVs.

During a follow-up inspection, IR 98-12, the NRC inspectors evaluated the actions taken by the licensee to address this issue and determined that the licensee had taken the necessary steps to boost the available control voltage and completed the supplementary tests necessary to demonstrate qualification of the EMRV solenoid valves. At that time, however, the licensee had not yet received the final test report from the testing laboratory and had not updated the qualification report to reflect the test results.

During the current review, the inspectors discussed the status of the above documents and determined that the EMRVs had been acceptably qualified and the qualification documents had been updated. To confirm the qualification status of the EMRVs, the inspectors reviewed selected portions of EQ File No. OC-301, Revision 3, which included the method and the results of the laboratory testing, Wyle Report No. 46882-0. This review determined that Wyle had used an acceptable method to establish the minimum required voltage for the actuation of the EMRV solenoids. This item is closed.

E8.2 Year 2000 (Y2K) Readiness (TI 2515/141)

On July 1, 1999, GPUN responded to NRC Generic Letter 98-01 to provide information concerning Y2K readiness at the OCNGS. The inspector reviewed one of the two systems that remain to be remediated to achieve Y2K readiness. The ETUDE software system for controlling personnel qualifications was completed by the remediation target date, August 15, 1999. The other system, REM/AACS/CICO, integrated software for managing personnel radiation exposure and controlling access to radiologically controlled areas, was scheduled to be completed by September 30, 1999.

IV. PLANT SUPPORT

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 General Observations (71750)

During radiologically controlled area (RCA) tours the inspectors observed that technicians: posted proper warning signs, conducted adequate radiological monitoring of personnel and materials leaving the RCA, maintained monitoring instrumentation functional and in calibration, and maintained radiation work permits (RWPs) and survey status boards up-to-date and accurate. Technicians observed activities in the RCA and verified that personnel complied with the requirements of applicable RWPs, and that workers remained aware of the radiological conditions in the area.

R1.2 High Contamination Area Awareness

a. Inspection Scope (71707,71750)

The inspector conducted periodic walkdowns of risk significant systems within contaminated areas of the plant. The inspector assessed radiation protection's (RP) radiological surveys and radiation worker radiological practices.

b. Observations and Findings

On August 23, the inspector noted that RP technicians had changed the radiological posting for entry into the shutdown cooling (SDC) pump room. Technicians had previously changed the posting from a contamination area (CA) to a high contamination area (HCA) to better control ongoing radiological work in the SDC pump room. Following completion of the work, technicians maintained the HCA posting. Reactor building equipment operators conduct a daily tour of the SDC pump room. For this tour, equipment operators use a standing RWP (No. 5O2473) and wear a partial set of protective clothing (booties, shoe covers, glove liners, and rubber gloves) as previously authorized by RP technicians. The inspector determined, based on discussions with RP supervision and equipment operators, that RP technicians did not clearly communicate to operators that they had re-posted the area. In addition, operators did not consistently demonstrate a questioning attitude and awareness concerning the more restrictive HCA posting.

In response, RP technicians conducted appropriate and detailed surveys to permit re-posting the area as a CA. Radiation protection supervision implemented administrative changes to require the RP group radiation control supervisor to conduct pre-shift briefs to operators detailing any changes in radiological conditions throughout the plant. Operations management counseled operators on attention-to-detail and good radiological work practices. Although operators entry into the posted HCA, without appropriate radiological guidance, was not in full accordance with plant radworker procedures; due to the low contamination measured in the areas where the operators

toured, and the lack of safety consequence, the inspectors considered this a minor issue not subject to formal enforcement action.

c. Conclusions

Radiological controls technicians did not effectively communicate changing radiological conditions in the shutdown cooling pump room to equipment operators. Reactor building equipment operators did not consistently demonstrate good radiological work practices to question a radiological posting change in the shutdown cooling pump room.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Fire Protection Equipment Usage

a. Inspection Scope (71750)

The inspector reviewed CAP 1998-0712, which documented problems with the timely restoration of self-contained breathing apparatus (SCBA) after equipment usage. The inspector assessed fire brigade equipment availability to determine corrective action effectiveness. The inspector toured plant areas where fire protection equipment was located, including the fire brigade turnout room. Additionally, the inspector reviewed the following procedures: 120.4, *General Response to Fire;* and 101.2, *Fire Protection Program;*

b. Observations and Findings

The inspector examined numerous pieces of fire protection equipment, including SCBAs. The examinations included periods before and after drills where fire protection equipment may have been used. The inspector determined that the required equipment was in place and in proper working condition. The procedures reviewed by the inspector were adequate, but he noted that attachment 1 to procedure 120.4, *General Response to Fires,* did not verify the restoration of fire protection equipment and SCBAs, but only reported the initiation of the actions. The inspector discussed this procedure with the Operations Director and the Manager, Nuclear Safety and Licensing. The managers informed the inspector that the fire protection coordinator was reviewing the timely restoration of SCBAs. On July 22, 1999, the fire protection coordinator initiated CAP 1999-0926, to document that management expectations regarding equipment restoration were not incorporated into fire protection procedures and that management expectations were not consistently understood. The Operations Director assigned corrective actions to revise fire protection procedures to expand the fire brigade leader's responsibility to include the timely restoration of this equipment. He also assigned a corrective action to reinforce management expectations for the timely restoration of fire protection equipment with the fire brigade leaders and operations department personnel.

c. Conclusions

Management and the fire protection coordinator initiated appropriate corrective actions to ensure the timely restoration of SCBAs and fire protection equipment.

S1 Conduct of Security and Safeguards Activities

S1.1 General Observations (71750)

During routine tours, the inspectors noted that security controlled vital and protected area access in accordance with the security plan, properly manned security posts, locked or guarded protected area gates, and maintained isolation zones free of obstructions.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The inspectors provided a verbal summary of preliminary findings to senior licensee management at an exit meeting on September 30, 1999. During the inspection period, inspectors periodically discussed preliminary findings with licensee management. Inspectors did not provide any written inspection material to the licensee. The licensee did not indicate that any of the information presented at the exit meeting was proprietary.

X2 Site Visit by NRC Managers

On September 9, 1999, the Director, Division of Reactor Projects (DRP), and the Chief, Projects Branch 7, DRP, visited the Oyster Creek facility.

PARTIAL LIST OF PERSONS CONTACTED

Licensee (in alphabetical order)

G. Busch, Manager, Nuclear Safety & Licensing
S. Levin, Director, Operations and Maintenance
D. McMillan, Director, Equipment Reliability
K. Mulligan, Plant Operations Director
J. Perry, Plant Maintenance Director
M. Roche, Director, Oyster Creek
D. Slear, Director, Configuration Control
R. Tilton, Manager, Assessment

NRC (in alphabetical order)

A. Della Greca, Senior Reactor Engineer
T. Hipschman, Resident Inspector
J. Schoppy, Senior Resident Inspector

INSPECTION PROCEDURES USED

Procedure No.	Title
37550	Engineering
37551	Onsite Engineering
61726	Surveillance Observation
62707	Maintenance Observation
71707	Plant Operations
71750	Plant Support
92903	Followup - Engineering
TI 2515/141	Review of Year 2000 (Y2K) Readiness of Computer Systems at Nuclear Power Plants

ITEMS OPENED AND CLOSED

Opened

Number	Type	Description
99-07-01	URI	Operability and reportability aspects concerning 34.5KV offsite power availability. (Section O2.1)

Opened\Closed

Number	Type	Description
99-07-02	NCV	Inadvertent Operation of a Core Spray Pump Breaker. (Section O4.1)
99-07-03	NCV	Equipment Control Procedure Non-compliance. (Section O4.2)

Closed

Number	Type	Description
98220-01023	EEI	Environmental Qualification (EQ) of the EMRVs. (Section E8.1)

LIST OF ACRONYMS USED

ADS	Automatic Depressurization System
AWG	American Wire Gage
CA	Contamination Area
CAP	Corrective Action Process
DC/dc	Direct Current
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDSFI	Electrical Distribution System Functional Inspection
EEI	Escalated Enforcement Item
EMRV	Electromatic Relief Valve
EQ	Environmental Qualification
ESW	Emergency Service Water
FDSAR	Facility Description and Safety Analysis Report
GOS	Group Operating Supervisor
GPUE	General Public Utilities Energy
GPUN	General Public Utilities (GPU) Nuclear
HCA	High Contamination Area
I&C	Instrumentation and Controls
IR	Inspection Report
JO	Job Order
LCO	Limiting Condition for Operation
MAPLHGR	Maximum Average Planar Linear Heat Generation Rate
NC	Normally Closed
NCV	Non-Cited Violation
NO	Normally Open
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
OCNGS	Oyster Creek Nuclear Generating Station
PDR	Public Document Room
PF	Pinion Failure
PM	Preventive Maintenance
PRG	Plant Review Group
QV	Quality Verification
RBCCW	Reactor Building Closed-loop Cooling Water
RCA	Radiologically Controlled Area
RP	Radiation Protection
RP&C	Radiological Protection and Chemistry
RWP	Radiation Work Permit
SCBA	Self-contained Breathing Apparatus
SDC	Shutdown Cooling
SDIV	Scram Discharge Instrument Volume
ST	Surveillance Test
STD	Static Time Device

TDDO	Time Delay Dropout
TDPU	Time Delay Pickup
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
UV	Undervoltage
VDC/Vdc	Voltage - Direct Current
Y2K	Year 2000