U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	91-39
Docket No.	50-219
License No.	DPR-16
Licensee:	GPU Nuclear Corporation 1 Upper Pond Road Parsippany, New Jersey 07054
Facility Name:	Oyster Creek Nuclear Generating Station
Inspection Period:	December 15, 1991 - January 18, 1992
Inspectors:	M. Banerjee, Resident Inspector T. Frye, Reactor Engineer J. Nakoski, Resident Inspector D. Vito, Senior Resident Inspector

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Reactor Projects Section 4B

Inspection Summary: This inspection report documents routine and reactive inspections conducted during day shift and backshift hours of station activities including: plant operations; radiation protection; maintenance and surveillance; engineering and technical support; emergency preparedness; security; and safety assessment/quality verification.

Results: Overall, GPUN operated the facility in a safe manner. A violation was identified with regard to a loss of equipment status control for two power supply breakers. Two noncited violations (NCVs) were noted. One NCV involved the discovery of an automatic time delay setting for isolation of the offgas header upon receipt of a high radiation signal in excess of the technical specification (TS) required 15-minute delay time (TS Table 3.3.1, Note E). The other NCV dealt with a failure to notify the NRC within four hours of notifying a state agency.

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The NRC inspection manual inspection procedure (IP) or temporary instruction (TI) that was used as inspection guidance is listed for each applicable report section.

EXECUTIVE SUMMARY

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Plant Operations

Overall, GPUN conducted plant activities in a safe manner. Operator response to plant conditions was good and management involvement was evident. A violation was identified which resulted from the licensee's loss of control of the breaker position for the electrical power supply to emergency service water (ESW) discharge to canal valves (V-3-87 and V-3-88). The equipment control issue notwithstanding, a system walkdown of the containment spray/ESW system found the system to be in an acceptable state of standby readiness.

The licensee was exercising good control over the use of overtime by licensed operators and non-licensed equipment operators.

The licensee delayed notifying the NRC after a state notification was made following identification of an environmental issue involving low pH in the new radwaste component cooling heat exchanger discharge water. The involved group shift supervisor (GSS) was appropriately counseled about the reporting requirement oversight.

Radiological Controls

Unclear guidance on frisking requirements while exiting the refueling floor was addressed by the licensee by additional posting and clarification of the guidance to Oyster Creek personnel.

Maintenance/Surveillance

The drywell sand bed removal effort continued; however, areas of very compacted sand were found which caused more than expected delays on the project. Desludging of the "A" radwaste evaporator was well controlled and conducted.

Engineering and Technical Support

During a regularly scheduled surveillance, emergency diesel generator No. 1 failed to attain full speed, synchronize to the bus and pick up load. A sequence fault resulting from a failure of the starter motors to engage with the engine within the second attempt was determined to be the cause. This part of the logic is bypassed during an emergency start. The licensee had previously determined that slightly increased start time would not affect the design basis capability of the diesels. Since this was the third occurrence of such failure between the two diesel generators since January 1991, the licensee is planning to implement a modification at the earliest available opportunity to improve the probability of starter motor pinion engagement. The licensee's response was commensurate with their commitment to maintain highly reliable diesel generators.

<u>Safety Assessment and Quality Verification</u>

The licensee found that the automatic time delay setting for isolation of the offgas header upon receipt of high radiation signal exceeded the technical specification required delay time. However, the delay time was within the system design requirements. This violation was determined to be an isolated occurrence and the licensee's corrective actions were adequate.

Due to problems in the development of the computer model for the Oyster Creek simulator, the licensee requested an exemption to extend the date of implementation and to allow use of the Nine Mile Point 1 simulator for 1992 operator examinations. The current schedule indicates that the new simulator will be available by August 1993.

A status summary of the more significant efforts being taken by the licensee in response to the 1990 Diagnostic Evaluation Team (DET) inspection is presented in section 6.2 of this report. Progress in several of these efforts was encouraging (root cause analysis, design basis reconstitution, plant decontamination efforts). Progress in the other noted areas was difficult to assess due to the efforts being in an early stage of implementation.

DETAILS

1.0 OPERATIONS (71707, 71710, 93702)

1.1 Operations Summary

The unit operated at or near 100% power during the inspection period. As noted in the previous resident inspection report (Inspection Report 50-219/91-37), power level was again limited for a significant portion of the inspection period to approximately 99% power due to a leak in a level column in the 1-5 heater drain tank, requiring isolation of the second stage reheaters.

The licensee entered the inspection period under a seven-day technical specification (TS) limiting condition for operation (LCO) action statement due to the inoperability of emergency service water (ESW) pump 52A. The pump had been declared inoperable on December 12, 1991, after failing an inservice test (IST) due to low developed differential pressure (dp). The pump was replaced, satisfactorily tested, and placed in service on December 18, 1991.

On December 19, 1991, the licensee noted that reactor coolant system unidentified leakage rate had increased from approximately 1.0 gpm to 1.7 gpm. After several days of investigation, the additional leakage was determined to be coming from the reactor water cleanup (RWCU) system relief valve V-16-76. The licensee has since considerably reduced this additional leakage by reducing the operating pressure of the RWCU system. The technical specification TS 3.3.D.1.a. limit for allowable reactor coolant system unidentified leakage is 5 gpm.

Power was reduced to approximately 90% for six hours on December 26, 1991, after a trip of the "B" recirculation pump. A soldered connection joining a wire from the rotor winding to the generator slip ring on the "B" recirculation pump motor-generator (MG) set had come loose causing the MG set and subsequent recirculation pump trip. The connection was resoldered and the pump was restarted.

Emergency service water system 1 was declared inoperable for approximately two hours on the morning of January 17, 1992, due to grass clogging the north end of the intake structure. Plant load was reduced to approximately 88% power while the intake screens were cleaned.

1.2 Containment Spray and Emergency Service Water System Walkdown

The inspector performed a walkdown inspection of the containment spray and emergency service water (ESW) systems. The final safety analysis report and technical specifications were reviewed to determine surveillance requirements and limiting conditions for operation for both systems. The containment spray system operating procedure was reviewed to determine the required equipment and component lineups to ensure system standby readiness. The operating procedure valve and electrical checkoff lists were compared against the containment spray and ESW system piping and instrument diagrams (P&IDs) to verify that the checkoff lists reflect a system condition which appropriately supports operation.

The inspector walked down the accessible portions of both the containment spray and ESW systems to verify that both systems were in standby readiness. The operating procedure valve and electrical checkoff lists were compared against the in-plant as-found valve and breaker positions to verify that both systems were lined up as required by the operating procedure. Both containment spray and ESW P&IDs were compared against the as-found system to determine if the P&IDs accurately reflected the as-built system configurations. System equipment and component conditions were observed for any indications that might degrade system operability. All system instrumentation were verified to have current calibration dates. Control room containment spray and ESW instrumentation was observed for proper indication. Control room valve and pump switch lineups were compared against that required by the operating procedure. The control room copy of the checkoff list was reviewed to ensure that it was complete and properly documented.

The following surveillance procedures were reviewed to determine if surveillances were being completed in accordance with technical specification requirements:

607.3.002, Rev. 37	Containment Spray System Automatic Actuation Test
607.4.004, Rev. 11	Containment Spray and Emergency Service Water System 1 Pump Operability and Inservice Test (IST)
607.4.005, Rev. 9	Containment Spray and Emergency Service Water Pump System 2 Operability and IST

The surveillance procedures were completed according to the frequency required by technical specifications. Data which entered the IST alert or action ranges was noted in the procedure summary sheets along with corrective action taken. Surveillance procedures reviewed were effective in assuring the operability of the containment spray and ESW systems. The inspector observed performance of the containment spray and ESW system 2 operability and IST (see section 3.3).

During review of the containment spray system P&ID against the operating procedure checkoff list and as-found system configuration, several minor valve position discrepancies were noted. The checkoff list requires that the containment spray pump casing drain valve for each of the four pumps (V-21-55, 56, 57 and 58) to be locked closed. This agrees with the as-found system configuration. However, the P&ID shows these four valves as closed vice locked closed. These discrepancies were brought to the attention of the group shift supervisor (GSS). The as-found configuration was determined to be correct, and a field change notice was initiated to correct the drawing.

During the review of the electrical checkoff list, breakers for two ESW valves were found out of the position required by the most recently completed electrical checkoff list. The as-found position of these breakers was closed while the required position per the checkoff list was open. The breakers in question were the power supply for the ESW discharge to canal valves V-3-87 and V-3-88. These valves are normally in a throttled open position to control ESW flow during operation.

These valves were once motor operated valves, but the motor operators were removed during the 13R refueling outage and manual operators were installed. In May 1991, the power supply breakers for these valves were racked out for removal of the valve motor operators. The breaker positions for V-3-87 and V-3-88 were verified on June 3, 1991, and June 8, 1991, while the breakers were tagged and racked out for the modification. A temporary change was implemented on June 7, 1991, to the electrical checkoff lists of Containment Spray Operating Procedure 310 to indicate that the breaker positions should be open vice closed since the valve operators had been removed. (This change was later determined to have been incorrect because closure of the breaker was still required to provide power for position indication of valves V-3-87 and V-3-88). Approximately one week after the breakers had been racked out for the modification, the tags were temporarily lifted from the breakers so that the breakers could be closed for testing purposes. The "temporarily lifted" tags were not replaced, and the breaker remained closed.

On January 15, 1991, the inspector notified the GSS that the breakers were closed, contrary to the position indicated on the current control room electrical checkoff list for Procedure 310. The GSS verified that the as-found breaker positions did not agree with the required electrical checkoff list positions. The GSS directed the checkoff list to be reperformed to reposition the breakers open. When an operator opened the breakers, it was noted that the valve position indication for V-3-87 and V-3-88 was lost at the local key lock switches and in the control room. The breakers were closed to restore valve position indication. The GSS stated that a change to Procedure 310 would be issued to list the correct position (closed) on the electrical checkoff list.

After reviewing the sequence of events, the inspector concluded that plant equipment control requirements had not been strictly adhered to. Specifically, Procedure 108, "Equipment Control," requires that equipment lineups shall not be performed on equipment or portions of systems while they are tagged out for maintenance or modification. In this case, the positions of the power supply breakers for V-3-87 and V-3-88 were inappropriately verified on June 3, 1991, and June 8, 1991, respectively, while the breakers were tagged and racked out. After the temporary lifting of the tags in mid-June 1991, formal control of equipment status for these breakers was effectively lost until January 15, 1992, when the equipment lineup discrepancy was discovered by the inspector. This is a violation (50-219/91-39-01). Had breaker status been verified in mid-June (i.e. after the temporary lift was completed, the original tags removed and the breakers placed back in the then specified position (open) on the Procedure 310 checkoff list), the licensee would have determined, prior to startup after the 13R refueling outage, that the temporary procedure change to the Procedure 310 equipment checkoff list on June 7, 1991, was incorrect and that the correct position of the power supply breakers was closed.

The walkdown inspection of containment spray and ESW resulted in no other notable findings. The equipment control issue notwithstanding, the inspector concluded that the system would perform its intended function and was in an acceptable state of standby readiness.

1.3 Operator Overtime

The inspector reviewed the overtime records for senior reactor operator (SRO) licensed personnel (group shift supervisors (GSS) and group operator supervisors (GOS)), the control room operators (CRO-RO licensed) and equipment operators (EO) for the period July 1, 1991, through December 29, 1991. Technical specification (TS) 6.2.2.2.2 requires that administrative procedures shall be developed to limit the working hours of unit staff who perform safety-related functions. Further, in the event that unforeseen problems require substantial amounts of overtime, additional guidelines are specified.

Station Procedure 106, Rev. 62, "Conduct of Operations," and 2000-ADM-2401.02, Rev. 1, "Extended Overtime, Consecutive Hours Worked - Implementation Procedure," implement the TS requirements to limit the working hours of licensee staff performing safety-related functions. The inspector reviewed Procedures 106, Rev. 62 and 2000-ADM-2401.02, Rev. 1.

The inspector reviewed the overtime records for the GSS, GOS, CROs and EOs. The CRO and EO overtime use is monitored by the operations shift assistant. For the GSSs and GOSs, overtime is controlled by the individuals with the hours worked approved by the plant operations or operations support managers. GSS and GOS overtime records were obtained from a computer based record storage system at GPUN's Reading, PA, office; the CRO and EO overtime records were available onsite. As a result of the inspector's review, no deviations from the TS requirements were identified. The inspector concluded that the use of overtime by licensed (and equipment) operators was being appropriately controlled by the licensee.

1.4 New Radwaste Service Water

On December 31, 1991, the licensee installed a temporary variation to provide cooling water to new radwaste (NRW) component cooling heat exchanger CC-H-2A from the fire protection system. Normal cooling water supply from the NRW service water system was not available due to a system outage for a planned modification.

On January 1, 1992, at 1 p.m., after determining that a discharge permit requirement was not met, the licensee notified the state of New Jersey. The permit required the pH at the discharge point to be between 6.5 and 8.5. The pH at the discharge point was determined to be 5.19. The NRC was notified about this environmental issue and state notification on January 2, 1992 at 8:55 a.m. The licensee later retracted this notification because of a stipulation in the permit which allowed departure from the pH limit for periods when the intake water was outside the limit. The fire protection system water is supplied from a pond formed by a small dam on Oyster Creek. The pH of the pond water was 4.85.

Station procedure 126, revision 12, "Procedure for Notification of Station Events," implements the requirements of 10 CFR 50.72. Enclosure 2, item 6, of procedure 126, requires the licensee to inform the NRC within four hours of notifying other government agencies regarding situations related to the protection of the environment. The inspector noted that the four-hour requirement of procedure 126 was exceeded. The licensee later determined that the event was not reportable to the state of New Jersey and was therefore not required to be reported to the NRC. However, the licensee still failed to comply with the requirements of procedure 126 by not informing the NRC within four hours of notifying the state. The licensee indicated that they had recognized the delay in NRC notification which resulted from an oversight on the part of the group shift supervisor (GSS). The licensee stated that the involved GSS was counseled with regard to the notification requirements. The safety significance of the event was minimal; the licensee identified the deficiency and deviation report number (DR #) 92-02 was issued documenting the occurrence; and the corrective measures were adequate and timely. This was not a willful or repeated violation such that corrective actions from a previous violation should have prevented it. Following the guidance provided in 10 CFR 2, Appendix C, item V.G.1, this violation was not cited.

The inspector reviewed the temporary variation and the engineering evaluation which supported the variation. The inspector also walked down the installed temporary variation. The engineering evaluation was detailed and the temporary variation was installed in accordance with approved paperwork. The inspector had no further questions.

1.5 Facility Tours

The inspectors observed plant activities and conducted routine plant tours to assess equipment conditions, personnel safety hazards, procedural adherence and compliance with regulatory requirements. Tours were conducted of the following areas:

- control and cable spreading rooms
- access control points
- diesel generator building
- old and new radwaste buildings
- intake area
- reactor building
- turbine building
- vital switchgear rooms

Control room activities were found to be well controlled and conducted in a professional manner. Inspectors verified operator knowledge of ongoing plant activities, equipment status, and existing fire watches through random discussions. The inspectors noted that plant winterization efforts were effectively accomplished during the inspection period.

2.0 RADIOLOGICAL CONTROLS (71707)

During entry to and exit from the 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 inspector observed activities in the RCA and verified that personnel were complying with the requirements of applicable RWPs and that workers were aware of the radiological conditions in the area.

2.1 Frisking Practices on the Refueling Floor

On January 8, 1992, the inspector questioned a frisking practice observed while exiting the refueling floor (119 ft elevation of the reactor building). A security guard frisked only his hands and feet while exiting, when the personnel contamination monitor (PCM-1) was out of service on the 95 ft elevation of the reactor building. The normal practice that the inspector had been instructed in by various radiological control technicians (RCTs) was to perform a whole body frisk at the 119 ft elevation frisking booth if the PCM-1 on the 95 ft elevation was out of service, due to a higher potential for contamination in this area involving hot particles.

This observation prompted the inspector to question the RCT on the 119 ft elevation about the frisking practice when leaving the refueling floor. The RCT stated that only a hand and foot frisk was required unless an entry into a contaminated area was made. The inspector questioned the RCT about the posting on the 119 ft elevation and 95 ft elevation door requiring a whole body frisk using the 95 ft elevation PCM-1 after exiting the 119 ft elevation. The RCT was not sure why the signs were there and emphasized that a whole body frisk was required if an entry into a contaminated area was made.

To further clarify the licensee's management position on the frisking requirement, the inspector questioned the radiological controls (RC) field operations supervisor who stated that the desired practice was to perform a whole body frisk using the PCM-1 on the 95 ft elevation after exiting the 119 ft elevation regardless of whether an entry had been made into a contamination area. Further, if the PCM-1 was out of service, a 2-minute whole body frisk at either the 95 ft or 119 ft elevation frisking booth was required. The inspector questioned the RC field operations supervisor on the adequacy of the frisking instructions posted at the 119 ft exit. The RC field operations supervisor agreed that additional guidance was needed to clearly identify the need to perform a 2-minute whole body fri:k using one of the frisking booths on the 95 ft or 119 ft elevation in the event the PCM-1 on the 95 ft elevation was out of service.

The RC field operations supervisor had additional frisking guidance placed on the PCM-1 directing personnel to use the frisking booth on the 95 ft or 119 ft elevation after exiting the 119 ft elevation if the PCM-1 was out of service. Also, to provide a refresher on management expectations for frisking when exiting the 119 ft elevation, the RC field operations supervisor included frisking guidance to all the RCTs in the Rad Con Field Operation Friday Update newsletter dated January 10, 1992. The inspector concluded that the licensee's efforts in response to this issue were adequate.

3.0 MAINTENANCE/SURVEILLANCE (62703,61726)

3.1 Drywell Sandbed Removal Update

Initial GPUN efforts to remove the sand from the area between the concrete shield wall and the primary containment (drywell) steel liner were discussed in NRC Inspection Report 50-219/91-37, section 3.6. The removal of the sand is intended to reduce the corrosion rate of the steel drywell (DW) liner.

As of January 16, 1992, slightly more than 37 barrels (55 gallon drums) had been removed from four of the ten bays and removal had been started in a fifth bay. The sand remaining in the areas worked was very compacted, located at the bottom of the sand bed area and between the exposed rebar and the concrete shield wall. Indications were that the sand has been removed from the steel DW liner except near the very bottom in the four areas worked.

The radiation exposure received for the sandbed removal project through January 15, 1992, was about 9.7 person-Rem. Initially, the exposure estimate for the entire project was 18 person-Rem. The major contributor to the higher than estimated exposure was the installation of a safety-harness lifeline on top of the torus. The lifeline installation estimated exposure was 0.8 person-Rem; however, as of January 15, 1991, 3.3 person-Rem had been accumulated. The exposure was significantly higher than expected due to the rework required when rebar was encountered during drilling for the installation of anchor bolts to attach the lifeline to the concrete shield wall. The lifeline installation was nearing completion at the end of the inspection period.

Observations of sand removal and operation of the diesel-powered vacuum were made by the inspectors throughout the inspection period. The sand removal project continues to be well controlled and conducted. During the plan-of-the-day meetings, the inspectors have observed concerns expressed with regard to the accumulated radiation exposure and questions on the need to remove all the sand. After discussing these concerns with the licensee, the inspectors concluded that the licensee remains committed to removing as much sand as practical and ensuring the sand in contact with the steel DW liner is removed to eliminate the galvanic corrosion mechanism. The residents continue to follow the sandbed removal project.

3.2 Radwaste Evaporator Desludging

On January 9, 1992, the inspector observed a portion of the removal of hardened sludge (desludging) from the "A" radwaste evaporator internals. The "A" radwaste evaporator was used to reduce the amount of high conductivity water collected from various sources by evaporation. Desludging was being done as part of the evaporator tube bundle replacement project to replace the old, leaking tungsten tube bundle with a new Inconel alloy tube bundle. Leakage from the old tube bundle in the "A" evaporator was the cause of the auxiliary boiler contamination identified in March 1990.

Control of the desludging was done using Special Procedure 91-015,Rev 0, "Desludging Evaporator A," with radiological controls established using ALARA review number (ARN) 91-522C, Rev. 4. The evaporator internals were hydrolazed (sprayed with a high pressure water source) to remove the hardened sludge. Periodically, the hydrolazing was stopped to allow the sludge-water mixture to be pumped into a storage container in preparation for solidification and shipping offsite. While the sludge-water mixture was pumped into the storage container, radiological control technicians (RCTs) performed radiation surveys of the pump discharge line, the work area adjacent to the evaporator inside the evaporator containment tent, and the general area inside the new radwaste truck bay for changing conditions.

The inspector observed the initial hydrolazing efforts, reviewed Special Procedure 91-015, and reviewed ARN 91-522D. Radiological controls were good. A group radiological control supervisor (GRCS), three RCTs, and a radiological control engineer were present during the initial hydrolazing effort. The contractors (TTI Engineering) performing the work were knowledgeable of the job requirements and radiological conditions for the work. Communications between the workers inside the containment tent, the pump operator, and the hydrolazer operator were good. Adequate instructions were provided in Special Procedure 91-015 and all prerequisites were completed before starting the work. ARN 91-522D provided the necessary instructions to control radiological conditions encountered during the work. Overall, the inspector concluded that the desludging of the "A" evaporator was well controlled and conducted.

3.3 Containment Spray and Emergency Service Water System Surveillance

On January 13, 1992, the inspector observed the performance of Surveillance Procedure 607.4.005, "Containment Spray and Emergency Service Water Pump System 2 Operability and Inservice Test." The purpose of this procedure was to verify the operability of the system 2 containment spray and emergency service water (ESW) pumps and obtain inservice test (IST) data on the pumps and selected valves.

The inspector observed the performance of this procedure on containment spray pump 51C and ESW pump 52C. After manual start of pump 51C, the inspector observed ESW pump 52C automatically start within the required time. With both pumps running, the inspector observed local instrumentation for proper system operation as indicated by containment spray discharge pressure, ESW system flow rate, and ESW heat exchanger differential pressure being within required values. The inspector also noted that control room indication of ESW/containment spray heat exchanger differential pressure, containment spray system flow, and ESW pump motor current verified proper system operation. The inspector verified proper control room switch lineup for system operation and plant computer indications for ESW system flow and torus water temperature.

After completion of the one-hour system operability run, the inspector observed IST performance on several ESW and containment spray system check valves. The inspector also observed the performance of vibration testing on ESW pump 52C. The IST was completed on all of these components satisfactorily. After completion of the surveillance, the inspector reviewed the completed procedure, including recorded data. All procedure prerequisites, instructions, and restoration steps were properly annotated when complete. All operability and IST data were properly recorded in the procedure, all operability data met required values, and all IST data were verified to be within the alert ranges.

The performance of this procedure required the coordinated efforts of several operators positioned at different stations, including the control room, intake structure and reactor building. Good communications between operators and knowledge of the procedure by these operators resulted in the performance of a surveillance procedure which effectively demonstrated the operability of the containment spray and ESW systems. No deficiencies were noted during the performance of this procedure.

4.0 ENGINEERING AND TECHNICAL SUPPORT (71707,40500)

4.1 Emergency Diesel Generator Failure to Start

During a regularly scheduled surveillance test on January 6, 1992, the emergency diesel generator (EDG) No. 1 failed to reach rated speed when given a manual start signal in accordance with the procedure. A "disable" alarm was received in the control room and a "sequence fault" light was received at the local panel. On a second attempt EDG No. 1 started normally and accelerated to the rated speed and was successfully loaded.

The licensee determined that failure to attain full speed during the first start was due to a failure of the starter motor pinion to engage the engine flywheel. The logic circuit allows several attempts; however, in a surveillance mode, if engagement does not happen by the second attempt a sequence fault is generated when the engine fails to attain full speed. Similar failures were observed during surveillances of EDG No. 1 on January 9, 1991, and on EDG No. 2 on August 26, 1991 (see inspection reports 50-219/91-01 and 50-219/91-25). The licensee's safety evaluation indicated that this part of the logic circuit is bypassed during an emergency start and a successful engagement on a third attempt would have no adverse consequences. This is because power to the vital loads will be restored within 21 seconds (vs. 20-second design basis requirement in the Final Safety Analysis Report). Due to low probability of pinion engagement failures, failures beyond the second attempt we,e not considered.

The inspector discussed the reason for the apparent increase in pinion engagement failures since January 1991 and the necessity of implementing a corrective action with the plant engineer. As indicated in previous inspection reports, the licensee had planned to implement a design modification to the diesel start circuit to increase the success rate of pinion engagement.

The licensee was planning to implement the modification during the next refueling outage (14R), but has recently reevaluated the benefit of implementing it prior to 14R. Current licensee plans call for completing the engineering and design by April 30, 1992 and installing the modification at the next available opportunity. The inspector concluded that the licensee's plan reflects their commitment to maintain highly reliable emergency diesel generators.

5.0 OBSERVATION OF PHYSICAL SECURITY (71707)

During routine tours, 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. Appropriate compensatory measures were taken when needed. Inspectors examined vital area access points and verified that they were properly locked or guarded and that access control was in accordance with the Security Plan.

5.1 Site Protection Shift Supervisor Tours

During a meeting with NRC Region I management on December 19, 1991, the licensee described measures taken to improve security management presence in the plant. One of the initiatives noted by the licensee was an increase in the frequency of site protection shift supervisor tours (two tours per shift was mentioned). The inspector reviewed the licensee's documentation and had discussions with security personnel to validate the statements made.

While there were no specific requirements for the frequency of site protection shift supervisor tours, the inspector concluded that the actual tour frequency did not meet the frequency stated during the December 19, 1991 meeting. After further discussion with the inspectors, site security management issued a directive to all site protection shift supervisors delineating security management tour guidelines. The guidelines basically stated that the on-duty site protection shift supervisor should perform at least one site tour during the eight-hour shift and document the results of the tour. The inspector found the guidelines to be adequate.

6.0 SAFETY ASSESSMENT/QUALITY ASSURANCE

6.1 Management Observation Team

On December 17, 1991, the inspector accompanied the Director, Radiological Controls (Rad Con) on a management observation team tour. The Director, Rad Con, observed maintenance activities on the 52A emergency service water (ESW) pump motor and the radiological controls implemented during the "A" evaporator tube bundle removal project.

While observing the 52A ESW pump motor maintenance, no poor practices were noted by the Director, Rad Con. The electricians performing the maintenance had a good knowledge of the safety measures established to allow relanding the power supply cables to the motor.

During observation of the "A" evaporator tube bundle removal work, poor rad con practices were observed by the inspector. When exiting the contaminated area, two of the four contracted workers removed their inner set of anti-contamination (anti-Cs) overalls and shoe covers using only cotton glove liners instead of their inner set of rubber gloves. The method taught in radiological worker training requires the inner set of gloves to be removed last, after all other anti-Cs have been removed. The inspector questioned the Director, Rad Con, about the observed practice. The Director, Rad Con, had not noticed that only cotton liners had been used by two of the workers and agreed with the inspector that using cotton liners to finish removing anti-Cs was a poor practice.

To address the issue, the Director, Rad Con, coached the four contracted workers on the observation regarding the unsuiting practice. Three of the four workers responded well to the coaching. Additional discussions between the Director, Rad Con, and the contracted workers' supervisor were held. Since the observation teams were aimed at promoting improved performance using positive coaching methods, no punitive actions were discussed by the Director, Rad Con. Rather, the need to be aware of the radiological conditions at Oyster Creek and the need to implement good radiological practices were emphasized during the discussions with the contracted workers and supervisor.

The inspector concluded that the coaching done by the Director Rad Con, focused on the weakness observed and was generally positive, constructive criticism. To reduce the perception that the management observation team tours will result in punitive actions, the Director, Rad Con, did not specify which of the workers was less than responsive to his coaching, when pressed for the information by the contracted workers' supervisor. This led the inspector to conclude that the Director, Rad Con, was adhering to the intent of the observation tours to affect a change in work practices at the worker level. The inspector felt that the Director, Rad Con, should have noticed the poor unsuiting technique.

6.2 Status of Diagnostic Evaluation Team (DET) Followup

On December 20, 1991, a meeting was held at the NRC Region I office to discuss the status of GPUN efforts in response to the findings of the Diagnostic Evaluation Team (DET) inspection of November 1990 and December 1990. The meeting had been requested by NRC so that GPUN could present the status of ongoing DET followup actions as well as the schedule and assigned priorities for the completion of current and future corrective actions. GPUN presented a summary of their understanding of the major issues of the DET, followed by a status of improvement initiatives.

GPUN accurately summarized the major issues of the DET, acknowledging that improvement was needed in the areas of root cause analyses (and corrective action systems) the quality of supervision and independent verification and the quality of work practices (and work control). A detailed presentation followed, which noted the status of a large number of activities either completed, ongoing, or planned in response to statements made in the DET report. The more significant of those activities are noted below:

1. Root Cause Analysis - The recently developed root cause standard which had been used on a trial basis since early 1991 was formally implemented in December 1991. The plant operations and engineering departments have been employing the root cause standard routinely since its trial implementation. The quality assurance and maintenance departments are taking actions to incorporate usage of the root cause standard within their departments by late 1992.

2. Design Basis Reconstitution - The DET report stated that the scope of safety system functional inspections (SSFIs) performed by GPUN appeared to be limited. GPUN acknowledged this and added that problems with design basis documentation contributed to the difficulty in doing SSFI reviews. As such, GPUN has concluded that more benefit can be derived from the development of design basis descriptions than doing SSFI reviews at this time. To date, nine (9) design basis documents (DBDs) have been completed (containment spray, ADS, emergency power, emergency service water, RCS, RPS, standby gas treatment and secondary containment, and circulating water). Five (5) DBDs are planned for completion in 1992 (core spray, feedwater and condensate, radiation monitoring, containment and drywell cooling). The goal is to complete approximately 33 DBDs at a rate of four to five DBDs per year.

3. Work Practices - GPUN is developing standards for the performance of routine activities at Oyster Creek. This is in response to DET noted inconsistencies in the performance and control of work activities. Many of the standards have been

developed and others are scheduled for completion within the next year. Initial discussions with working level personnel are intended to verbally convey management expectations in the areas covered by the standards and to evoke worker feedback.

The management observation teams concept has been in effect since September 1991. This effort, which is separate from routine department-specific observation practices, is intended to focus on the improvement of general work and radiological control practices through observation and constructive coaching of workers and first line supervisors in the field. GPUN noted during the meeting that lessons learned from the management observation team effort will be fed back to the department-specific routine observation process.

Improvements are also planned for the onsite computerized work control system (GMS2) to provide for clearer definition of work priorities, scheduling, and work package content.

4. Maintenance Component Review Teams - In response to DET comments regarding deficiencies in the preventive maintenance (PM) program, GPUN had initially considered development of a Life of System Maintenance Program (LOSMP). When efforts to implement LOSMP proved cumbersome, GPUN decided to approach PM improvement on a component-type basis. Efforts began in August 1991 to form review teams, under maintenance department direction, for five generic types of components (valves and valve operators, rotating equipment, electrical equipment, instrumentation and controls, and heat exchanges (with other miscellaneous mechanical equipment)). These teams will use available information, including initial LOSMP information, reliability-centered maintenance (RCM) data, and failure trending information to develop a comprehensive PM program for similar types of equipment. While some effort is underway, teams will not be completely formed until March 1992. The licensee projected that the effort will take approximately 2 years.

5. Integrated Scheduling - The overall planning and scheduling function has recently been placed under site control. Changes have been made to the maintenance work tracking system (GMS2) and the scheduling program (PROJECT/2) to promote better coordination of activities. A formal training program for maintenance planners is under development and is scheduled to begin in mid-to-late 1992.

6. Plant Decontamination Efforts - The licensee is continuing efforts to reduce plant contaminated areas as much as practicable to promote a reduction in challenges to the worker, improve working conditions, and help meet ALARA goals. By the end of 1991, the total plant contaminated area was slightly above 56,000 ft^2. This amount has been steadily reducing over a number of years and is at its lowest level since 1980. Efforts are planned for 1992 to further reduce the remaining

6,000 ft^2 of plant contaminated areas which the licensee estimates are feasible to recover.

7. Procedure Upgrade - A newly developed procedure writers guide is being used to upgrade procedures site wide. The schedule for completion presented by the licensee was as follows:

   - Operations Procedures
     chemistry - December 31, 1992
     radwaste - December 31, 1992
     operations - December 31, 1994

   - Maintenance Procedures - April 30, 1992

   - Surveillance Procedures - December 31, 1996

8. PREP (Process Re-Engineering Program) - PREP was developed in August 1991 to evaluate technical processes within GPUN which have been noted to be cumbersome and/or ineffective and propose changes to or complete overhaul of each process to improve its effectiveness and acceptance. The initial area of evaluation was equipment control and temporary modifications (switching and tagging). Implementation of the PREP recommendations in this area are currently being assessed by GPUN management. The next area for PREP evaluation is project management.

9. Simulator Implementation - Problems have been encountered in the development of the computer model for the Oyster Creek simulator. GPUN has requested an exemption to extend the date of implementation and to allow use of the Nine Mile Point Unit 1 simulator for the 1992 operator examinations. Subsequent to the meeting, the licensee provided the scheduled simulator delivery dates as December 30, 1992, and use of the simulator in licensee examinations as August 30, 1993.

The schedules for completion of these and a number of other proposed improvement initiatives were noted in the GPUN presentation package for the December 20, 1991, meeting. The document will be placed on the docket at the request of the Regional Administrator. The residents will continue to follow the licensee's progress in these areas.

6.3 In Office Review of Licensee Event Reports (LER) (IP 90712)

NRC inspectors reviewed the following LERs and verified the timeliness of the LER and that a complete event description was provided with root cause identified and that other pertinent information was complete. In addition, the need for onsite review was assessed.

LER NO.	DESCRIPTION
91-006	Degradation of Instrument Response due to Inadequate Design Control of Instrument Snubber Use (Isolation Condenser Pipe Break Sensors)
91-007	Air Ejector Offgas Isolation Time Delay Found Out of Specification during Surveillance Testing

The text of LER 91-006 adequately described the event occurrence and appropriately reflected the cause, safety significance, and corrective actions being taken in response to the event. For inspection followup of this event see Inspection Report 50-219/91-32.

While the documentation of LER 91-007 was adequate, inspector review prompted further questions related to the sequence of events and the implementation status of actions being taken to prevent recurrence. The event involved the discovery, on November 2, 1991, of an automatic time delay setting for isolation of the offgas header upon receipt of a high radiation signal in excess of the TS required delay time (20 minutes, 18 seconds, vice 15 minutes (TS table 3.3.1, Note E)). The cause was determined to be the omission of certain vendor information in the surveillance test setpoint determination after a faulty time delay relay was replaced with a different model relay on August 24, 1991. The safety significance of the event was determined to be minimal because the "as-found" out-of-specification time delay setting was within the design offgas header holdup time of 30 minutes and manual offgas system isolation is directed by operating procedures if automatic isolation does not occur. However, inclusion of the vendor noted temperature effects on the time delay relay in the setpoint determination would have precluded this issue altogether.

The inspector reviewed the modification package, as well as plant Procedure 124.2, "Control of Plant Engineering Directed Corrective Changes and Modifications," and Technical Functions Procedure EMP-002, "Requirements for Modifications, Corrective Changes and Facility Changes." The inspector also interviewed the responsible engineer with regard to the development of the modification package.

The inspector concluded that the procedures controlling the modification process contained adequate guidance with regard to the inclusion of environmental effects in final surveillance setpoint determination. The engineer assigned to the modification incorrectly assumed that the replacement time delay was a replacement-in-kind and that no setpoint changes would be necessary. The engineer was notified of the surveillance test failure on November 2, 1991, and was directed to reevaluate the surveillance test setpoint determination and have the time delay "as-left" setpoint changed accordingly. The "as-left" setpoint was changed on November 4, 1991.

To preclude recurrence, the licensee has issued this LER as required reading for engineering department personnel. The licensee is also reviewing the procedures which control the modification process to determine if any changes can be made which will further clarify setpoint considerations. This effort is scheduled to be completed by March 16, 1992. This violation of TS Table 3.1.1, Note E is not being cited because of the minimal safety significance of the issue, the isolated nature of the violation, the adequacy of existing modification control procedures, and the implementation of appropriate corrective actions.

The current "as-left" setpoint for the time delay is considerably lower than the "as-left" setpoint for the old relay (10 minutes vice 14.5 minutes) due to the large variability due to temperature. For this reason, the licensee is currently developing a modification package to replace the current time delay relay with a solid state device which is not as susceptible to temperature effects.

7.0 REVIEW OF PREVIOUSLY OPENED ITEMS (92701,92702)

(Closed) Unresolved Item 50-219/91-07-02. This item dealt with how the licensee defined the technical specification (TS) time intervals for the various action statements of limiting conditions for operations (LCO). The NRC questioned the licensee on the length of time that the No. 1 emergency diesel generator (EDG) and standby gas treatment system (SGTS) I were out of service for maintenance between March 2 and April 1, 1991. In response, the Plant Operations Director issued a memorandum to operations department managers and licensing personnel regarding guidance on applying TS LCO action statement time intervals. In the memorandum dated April 29, 1991, licensing indicated a change to Station Procedure 106, "Conduct of Operation," would be made to include this memorandum guidance.

The inspector reviewed the April 29, 1991, memorandum and the temporary procedure change (TPC) to revision 62 of procedure 106. The TPC dated December 17, 1991, incorporated the guidance of the memorandum. The memorandum provided clear and appropriate guidance for applying technical specification LCO action statement time intervals. No inspector concerns remained. This item is closed.

(Open) Violation 50-219/91-01-02 and Unresolved Item 50-219/91-05-01. The violation addressed lack of environmental qualification (EQ) documentation on electric splices in two core spray booster pump (P-20-2A and 2C) and two containment spray pump (P-21-1A and 1B) motors. Additionally, the violation also indicated that auditable documentation to establish the traceability of the splices in core spray pump motor P-20-1B was not maintained. The unresolved item questioned whether a program weakness existed in establishing traceability after the licensee identified that the core spray pump motor P-20-1A splices were also not of the qualified configuration.

In their response to the notice of violation, the licensee disagreed with two statements in the inspection report transmittal. These statements communicated NRC's concern that, (1) a violation which may show that weaknesses in the licensee's EQ program had existed since February 1990 and were not addressed, and, (2) that an operability determination was not completed and corrective action taken before December 1990.

The licensee stated that as a result of a review involving splices in four pump motors in late 1989, the EQ group identified inconsistencies in the baseline data. Information available on walkdown sheets, which the EQ file used for traceability, did not clearly indicate the qualified configuration. The licensee also knew that a prior ECCS modification installed during 1975 changed some of the splices. Job orders were submitted in December 1989 to conduct an inspection during an outage of sufficient duration. The primary purpose of these job orders, however, was to take measurements of the existing splices such that replacement splices could be specified for cable testing during the upcoming 13R refueling outage. Therefore, the job orders did not clearly establish what to look for in terms of determining whether a qualified splice configuration existed or not.

During the inspection of splices on containment spray pump motors (P-21-1A and P-21-1B) on February 7, 1990, the EQ engineer identified that the splices did not conform to the qualified configuration. Documentation was prepared to address the operability of the splices. The splices were to be replaced during an upcoming outage of sufficient duration. Identification of this EQ deficiency and the operability determination documentation, however, were not conveyed to Oyster Creek station. The job order on the other two pumps, core spray booster pumps (P-20-2A and P-20-2C) was closed out after Oyster Creek maintenance took measurements for replacement splices and the existing unqualified configuration of these splices remained unknown.

During December 1990 the EQ group determined that a deviation existed in core spray booster pump motor P-20-2A and 2C splices and expanded the operability determination to address the unqualified splices in the pump motors. Oyster Creek station was informed; splices on P-20-2C were opened, inspected and sent to the laboratory for analysis to confirm material and configuration to support the operability determination. Qualified Raychem splices were installed on December 15, 1990, in this pump motor.

During February 1991, the licensee also found that a 1985 work request modified splices in core spray pump P-20-1A such that they were not in an environmentally qualified configuration. An inspection performed by the licensee confirmed this information. A deviation report was written and an operability determination documentation was prepared. This prompted the NRC to question if the splice deficiencies indicated an EQ program weakness (unresolved item 50-219/91-05-01).

During the 13R refueling outage, the licensee inspected the remaining ECCS pump motor splices. Based on the results of the inspection, the licensee concluded that none of the splices on the 12 ECCS pump motors were of original GE supplied "black glass tape with red glyptol varnish," a configuration qualified in the licensee's existing EQ file No. OC-388 (revisions 0 through 4). The splices were found to consist of various Scotch brand tapes with EPR, PVC, and Si-rubber as specified in GPUN installation specification. Revision 5 of the EQ file OC-388 was prepared to qualify these tape splices.

The licensee determined that the original GE supplied splices were replaced during a plant modification conducted in 1975. As a result, the November 26, 1985, GPUN certification to NRC that adequate inspections had been performed to provide reasonable assurance that Oyster Creek met the requirements of 10CFR50.49 was shown to lack adequate basis.

At the end of the 13R outage, all ECCS pump motor splices that were found to be of a different configuration than the splices qualified by EQ file No. OC-388, Rev. 5, were replaced with qualified Raychem splices.

Based on the above information, the inspector concluded that the licensee had sufficient reasons to question the adequacy of the walkdown sheets in establishing traceability of the splices since late 1989 or early 1990. However, the licensee did not expedite followup of this issue. As a result, plant operations and management were not informed in a timely and comprehensive manner about the existing EQ deficiency in the plant, even when primary responsibility of determining equipment operability rests with them. The inspector concluded that after identification in February 1990, the licensee did not address the issue in a timely manner. The inspector concluded that the licensee's dependence on questionable walkdown sheets without any other verification resulted in having unqualified splices on EQ equipment and a delay in identifying this condition. This showed a weakness in the licensee's EQ program. The second statement in the inspection report disputed by the licensee again pointed out the licensee's delay in addressing the issue, because even after questions came up in early 1990, core spray booster pump motor splices were not inspected until December 1990.

The inspector reviewed EQ file OC-388, Rev. 5, which qualified the EPR/PVC/Si-rubber tape splices on ECCS pump motors to the DOR guidelines. The inspector noted that the licensee did not address the performance requirement of these splices involving KW values much higher than the test specimen. The licensee indicated that due to a large available margin in the test parameters over the specified environmental conditions and the larger thickness of the installed splices, higher KW values would not pose a qualification problem. The licensee agreed to address this and the geometrical configuration difference between the tested and installed splices and update the EQ file.

In their response to the notice of violation, the licensee indicated that new items would be added to the existing computerized engineering data base to enhance future identification, control and documentation related to EQ items. The licensee used supplemental SCEW (SSCEW) sheets to implement the required control over EQ configuration during plant maintenance. No SSCEW sheets previously existed for common items like splices, terminal blocks, and cables. The inspector reviewed the splice information existing in the GMS2 data base for core spray pump motor P-20-1B. This included the description of the qualified configuration, qualification method, environmental parameters, operating time, qualified life, EQ reference documents, and SSCEW requirements which would identify any maintenance requirements and the qualified replacement splices for the application. Qualified Raychem splices were designated as replacement for these tape splices. The licensee also indicated that the approved spare parts list only allows qualified Raychem splices in EQ applications. The inspector concluded that the enhancement of the GMS2 data base would improve EQ configuration control.

In their response to the notice of violation the licensee also indicated that an evaluation of the process to identify and correct EQ deficiencies was being conducted. An investigation performed by the QA audits group to determine the circumstances surrounding the discovery of nonqualified splices in the two containment spray pump motors is described in audit report S-OC-91-15 dated November 27, 1991. This report also addressed the generic implication of finding unqualified splices in all ECCS pump motors. At the end of the inspection period the inspector was still reviewing this report.

(Open) Violation 90-19-01. This violation involved configuration control deficiencies existing at Oyster Creek which were identified during an NRC inspector walkdown.

In their response to the notice of violation, the licensee indicated that a walkdown was conducted to identify other potential configuration control items and that all known configuration differences had been properly documented with controls added in accordance with Procedure 108, "Equipment Control."

To evaluate the licensee's disposition of known configuration control issues, the inspector reviewed actions taken for items in the licensee's September 17, 1990, reactor building walkdown. The inspector verified by a sample walkdown that the licensee's corrective actions to initiate temporary variations were done. The licensee was planning to update the walkdown list to indicate the completion status of all action items. Engineering evaluation PE 421-90, which supported the adequacy of a red rubber hose with valves at both ends as a reactor building penetration, required periodic inspection of this installation. The temporary variation (TV) specified weekly inspections. The inspector could not locate any documentation which indicated that this weekly inspection was being performed. The licensee concluded that the inspection was being performed via a weekly preventive maintenance (PM) until June 1991; however, the PM was discontinued after that. The licensee believes that during a turnover between two different operation support engineers responsible for the weekly PM, this item was inadvertently dropped. The licensee is currently reviewing the matter to determine what corrective action needs to be taken. Oyster Creek Procedure 108 stated that TVs should be controlled by procedures or work controlling documents which would incorporate all specified requirements, including any checks required to monitor performance.

The licensee stated that organizational changes in plant maintenance, issuance of job planning guidelines, and training on procedure 108 are expected to reduce the probability of uncontrolled and undocumented configuration changes. The inspector reviewed the job planning and the lesson plan on procedure 108 training. The licensee indicated that a new training module was being prepared with examples of configuration control issues which would be completed by April 30, 1992. The inspector concluded that the licensee had initiated a good effort in this area and will review the training module when completed.

The licensee indicated that additional emphasis on configuration control was provided via required reading and crew meetings. Certain plant procedures that required engineering evaluation prior to configuration changes were made required reading for various maintenance supervisors, job coordinators and planners. The inspector verified the required reading transmittal; however, the licensee did not have any record of crew meetings where configuration control issues were discussed.

The response to the notice of violation also indicated that further assessment of how configuration control failures were occurring would be conducted to perform a more comprehensive root cause determination. This activity is currently being finalized.

This violation will remain open until licensee's verification that corrective actions resulting from plant walkdowns are all completed, the required training module is developed, and a comprehensive root cause analysis and corrective actions are finalized.

8.0 INSPECTION HOURS SUMMARY

The inspection consisted of normal, backshift and deep backshift inspection; 39 of the direct inspection hours were performed during backshift periods, and 20 of the hours were deep backshift hours.

9.0 EXIT MEETINGS AND UNRESOLVED ITEMS (40500,71707)

9.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to senior licensee management on January 27, 1992. During the inspection, licensee management was periodically notified verbally of the preliminary findings by the resident inspectors. No written inspection material was provided to the licensee during the inspection. No proprietary information is included in this report.

9.2 Attendance at Management Meetings Conducted by Other NRC Inspectors

The resident inspectors attended exit meetings for other inspections conducted as follows:

January 17 (Solid Radwaste/Transportation)
Report No. 50-219/92-01

At these meetings the lead inspector discussed preiiminary findings with senior GPUN management.

9.3 Unresolved Items

Unresolved items are matters for which more information is required to ascertain whether they are acceptable, violations or deviations. An unresolved item is discussed in section 7.0 of this report.