U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	95-22
Docket No.	50-219 72-1004
License No.	DPR-16
Licensee:	GPU Nuclear Corporation 1 Upper Pond Road Parsippany, New Jersey 07054
Facility Name:	Oyster Creek Nuclear Generating Station
Location:	Forked River, New Jersey
Inspection Period:	October 16, 1995 - November 19, 1995
Inspectors:	Larry Briggs, Senior Resident Inspector Stephen Pindale, Resident Inspector George Morris, Reactor Engineer Joseph Nick, Radiation Specialist

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Projects Branch No. 7

Inspection Summary: This inspection report documents the safety inspections conducted during day shift and backshift hours of station activities including: plant operations, maintenance, engineering, plant support, and safety assessment/quality verification. The Executive Summary provides the inspection findings and conclusions.

EXECUTIVE SUMMARY

Oyster Creek Nuclear Generating Station
Report No. 95-22

Plant Operations

The licensee operated the plant safely. Control room operators promptly and effectively responded to multiple equipment failures associated with the cooling fans for main transformer M1B. Several documentation and communication weaknesses by licensed and non-licensed operations personnel resulted in a delayed response to a low intake level condition in the North intake bay.

Maintenance

Maintenance and surveillance activities were conducted safely and in accordance with station procedures. Fire penetration inspections in the condenser bay were deferred due to concerns related to high radiation exposure. The associated evaluation provided a well-developed basis and good compensatory and contingency actions. An aggressive scope of maintenance activities for a planned load reduction was effectively and safely implemented.

Engineering

The onsite engineering organization properly prioritized and executed work activities. System engineering identified degraded control rod drive pump "A" performance, and recommended timely replacement of the rotating element. The engineering organization provided thorough followup and evaluation of the issues emerging during the associated maintenance activity. The licensee promptly responded to an industry notification regarding a reactor protection system (RPS) single failure vulnerability and determined that the Oyster Creek RPS design was not susceptible. Appropriate calculations, modifications, and procedure changes have been implemented to assure satisfactory voltage exists at safety-related equipment. Sufficient corporate interface between the licensee and Jersey Central Power and Light has been established to provide assurance that future configuration changes to the combustion turbines will be known by the responsible GPUN personnel.

Insufficient progress has been made in developing a formal diesel generator reliability program. This was discussed with operation management and they indicated that this will be resolved by February 28, 1996. The combustion turbine reliability program does not include an input for individual combustion turbine availability, even though both units are required to meet the system reliability goal. An inspector follow item (IFI 50-219/95-22-01) has been opened regarding a future Nuclear Safety Assessment review of the combustion turbine reliability and maintenance program.

Plant Support

Routine observation of station personnel by the inspectors indicates that radiological controls and security program requirements were being effectively implemented by the licensee and followed by station personnel.

Oyster Creek continued to maintain an overall effective program for occupational radiation protection including processing, packaging, storing and shipping radioactive waste and radioactive materials. Audits and appraisals by the licensee's staff continued to improve the quality of the program. Minor staffing changes were noted including reductions in some areas. Personnel qualifications of the licensee's staff were excellent and the training for hazardous/radioactive material handlers was appropriate.

Implementation of the solid radioactive waste program was very good including processing and handling of radioactive waste, analysis of radioisotopes in the waste, and storage of radioactive waste. The radioactive waste and radioactive material shipping program was effectively implemented and records were maintained in good order.

Safety Assessment/Quality Verification

Station personnel and management provided significant attention to the failure of the primary power supply for continuous instrument panel CIP-3 due to the potential adverse consequences in the event of an additional power supply failure. An appropriate level of heightened sensitivity was likewise provided to continuing flow and speed fluctuations observed within the reactor recirculation control system. Some relevant information was not properly included in the licensee event reports submitted this period.

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DETAILS

1.0 PLANT OPERATIONS (71707,93702,71750)

1.1 Operations Summary

The plant was operating at full power at the beginning of this inspection period, and continued until November 9, 1995, when a planned load reduction for testing and maintenance was completed. After reducing power to 40% for quarterly main steam isolation valve testing, power was maintained at 70% to perform maintenance on the "C" feedwater pump (seal and bearing replacement). Other activities during the downpower included reactor recirculation (RR) flow control system troubleshooting, RR motor-generator set preventive maintenance, continuous instrument panel CIP-3 repairs and hydraulic control unit scram inlet/outlet valve actuator replacement.

Full power operation resumed on November 14, 1995, until a loss of cooling fans for main transformer M1B resulted in a manual rapid load reduction to 60% power. After power was restored to a sufficient number of the cooling fans, the unit was returned to full power on November 15, 1995, and continued until the end of the inspection period.

1.2 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 room
- cable spreading room
- diesel generator building
- new radwaste building
- old radwaste building
- transformer yard
- intake area
- reactor building
- turbine building
- vital switchgear rooms
- access control points
- fire pump building

Control room activities were found to be well controlled and conducted in a professional manner with staffing levels above those required by Technical Specifications. The inspectors verified operator knowledge of ongoing plant activities, the reason for any lit annunciators, safety system alignment status, and existing fire watches. The inspectors also routinely performed independent verification from the control room indications and in the plant that safety system alignment was appropriate for the plant's current operational mode.

1.3 Main Transformer Cooling Fan/Breaker Failures

On November 14, 1995, while operating at 95% power, several cooling fans for the M1B main transformer failed. Control room operators quickly responded to the associated control room annunciators, and commenced a rapid power reduction per station procedures. Within the following 20 minutes, operators locally restored 12 of the 16 cooling fans, and the power reduction was terminated at about 60% power. The failed bank of fans was isolated, and power was subsequently increased. The main transformer oil temperatures remained normal throughout the transient. The other main transformer, M1A, remained functional and unaffected.

The M1B transformer has four banks of cooling fans. In the above event, which occurred during a severe rain storm, two of the four fans in one of the banks experienced an electrical fault. However, the individual fan breakers failed to trip as expected. As a result, the main 480 volt breaker (for all 16 fans) tripped, and the electrical supply automatically transferred to the backup 480 volt breaker. Since the faulted condition still had not cleared, the backup breaker also tripped. Consequently, all 16 fans remained tripped. When the operators responded, they were able to electrically isolate the affected fan bank, and restore power to the remaining three banks. Two banks were adequate for heat removal for the existing ambient conditions.

The licensee initiated a deviation report to document this event and to develop corrective actions. The transformers are maintained by the owner of Oyster Creek (JCP&L). At the end of the inspection, the root cause evaluation for the fan and breaker failures had not been completed. Both JCP&L and GPUN were collectively evaluating this event. The inspector reviewed the licensee's response to this event. Operator response, particularly those to identify and correct the immediate problems, was prompt and effective.

1.4 Low Intake Water Level and Delayed Entry Into Response Procedure Due to Performance Weaknesses

On November 13, 1995, at 10:05 a.m. the control room was informed by an equipment operator (EO) that the intake water level was low at the North intake bay (level is measured between the trash rack and the pump suction). The control room operators promptly entered the associated abnormal operating procedure, 2000-ABN-3200.32, "Response to Low Intake Level," since the entry condition of 2.0 feet below mean sea level (MSL) had been exceeded. The actual level was about 3.0 feet below MSL. After following the actions of the procedure, including securing one of the four circulating water pumps, and cleaning the trash racks, level was restored to normal and the ABN was exited. The control room operators responded appropriately to the low intake level. However, the licensee's ongoing service water self-assessment team subsequently identified documentation and communication problems involving a delay in identifying and correcting the low intake level condition.

The team identified that some of the completed EO shift tour sheets for November 12 and 13 failed to circle intake level readings to highlight lower than the acceptance value levels and that the associated senior reactor operator (SRO) review separately failed to note the low level problem. For the 12-8 shift on November 13, both level readings (North and South intake bays) were less than the acceptance value of 0.0 feet MSL as indicated and circled on the tour sheet. Further, the North bay was low enough to cause entry into the ABN procedure. However, the control room apparently was not notified. The SRO review of the November 13, 12-8 tour sheet identified the recorded (low) levels. The SRO subsequently was redirected to the feedwater pump room for a pending start of a feedwater pump, and failed to followup on the low intake level condition. It was not until the next shift (8-4), November 13, that proper level recording, communications, and response resulted in entering the ABN and fully resolving the intake problems.

The Operations department responded promptly to this concern identified by the self-assessment team. A deviation report was filed and a formal event critique was initiated to determine root causes and to develop corrective actions.

The inspector monitored the licensee's efforts and determined them to be appropriate. Short term planned actions include reinforcing management's expectations with regard to logkeeping and shift communications to all shift operations personnel. Although this appeared to be an isolated event, the licensee plans to conduct a verification audit of other completed EO tour sheets.

The inspector concluded that several weaknesses were apparent in this area including poor attention to detail during EO tours and SRO tour sheet review/followup and poor communications among operations department shift personnel. The licensee's response to this event was prompt and appropriate. The safety significance of this event was minimized because actual ultimate heat sink (intake canal) inventory was not compromised and intake pump performance was not challenged by the lower than normal water level downstream of the trash racks.

The above event represents a violation of licensee procedures, including procedure 106, "Conduct of Operations," and 2000-ABN-3200.32 (due to delayed entry). However, this issue was identified by the licensee, was of minor safety significance, and is being treated as a non-cited violation consistent with Section VII of the Enforcement Policy (NUREG-1600).

1.5 Update on Independent Spent Fuel Storage Facility

The inspectors reviewed the licensee's plans for the independent spent fuel storage facility (ISFSF) for information and inspection planning purposes. The licensee was in the process of upgrading the reactor building crane for use during fuel transfer operations. The fuel bundle recovery in the spent fuel pool was completed in October 1995. The annual inventory and verification of spent fuel had also started. The remaining fuel bundle inspections were to be completed by the end of November 1995.

Site preparations were also started on the spent fuel storage pad located outside the protected area. A fence around the pad was almost complete and a gate was to be installed in the near future. The electric and security systems were also near completion and the system check was scheduled for late November 1995.

Actual component deliveries were expected to start in December 1995 with the delivery of a total of ten horizontal concrete storage units via barge. The licensee had planned to use a heavy hauler to transfer the units from the barge in the discharge canal to the pad. Structural steel was also scheduled for delivery in December 1995. After the horizontal units were placed on the pad, the structural steel would be used to complete the storage units. Turnover of the site from startup and test to operations for fuel transfer was expected to occur in January 1996.

The licensee was also planning the crew training of the dedicated staff for fuel transfer. Two crews of five individuals were assigned to the project. The crews were comprised of two mechanics and three station helpers (plus welders and alternates). Receipt of the transfer equipment was expected in mid-January 1996. The first dry run using the equipment was scheduled for the first week in February 1996. A second dry run with dummy fuel was planned for mid-February 1996. The tentative date for the first actual fuel move was scheduled for the first week in March 1996. Each fuel canister transfer (holding 52 fuel assemblies) will take approximately 8 days. Eight canisters are scheduled for transfer before the end of May 1996.

2.0 MAINTENANCE (62703,61726)

2.1 Maintenance Activities

The inspectors observed selected maintenance activities on both safety-related and non-safety-related equipment to ascertain that the licensee conducted these activities in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards.

The inspector observed portions of the following activities.

Job Order (JO)	Description
500906	Repair Rotary Inverter Drive Motor "On" Light
501454	Overhaul Control Rod Drive Inlet Scram Valves
501460	Overhaul Control Rod Drive Outlet Scram Valves
53317	Station Air Compressor 1-3 Modifications
60543	Control Rod Drive Pump Rotating Element Replacement
62907	Replace "C" Feedwater Pump Inboard and Outboard Seals and Bearings

The inspectors concluded that the above activities had been approved for performance and were conducted in accordance with approved job orders and applicable technical manuals. Personnel performing the activities were knowledgeable of the activities being performed and were observing appropriate safety precautions and radiological practices. During the downpower beginning November 9, 1995, a relatively large scope of work was identified to address equipment issues. The inspector concluded that the work activities were completed safely and effectively.

2.2 Deferred Fire Penetration Inspections Due to High Radiation Exposure

The Oyster Creek fire protection program requires that fire penetrations be visually inspected at least once per 18 months, which is completed by a periodic surveillance task. With the exception of the approximately 100 penetrations in the condenser bay, all penetrations have been recently inspected. The licensee completed an evaluation to defer the 100 condenser bay penetration inspections until the 16R refueling outage in September 1996, primarily due to excessive radiation dose to workers (greater than 600 mR).

The engineering evaluation, dated November 7, 1995, documents that the condenser bay is protected by an automatic wet pipe sprinkler system. Interim actions will be implemented by the licensee until the outage, and will include hourly remote video inspections of the condenser bay areas using an existing installed video system. Additional contingency actions have been planned and documented in the event a fire develops in the condenser bay.

The inspector discussed the proposed actions with the responsible system engineer and reviewed the related engineering evaluation. The inspector concluded that the evaluation was acceptable; and that sufficient compensatory and contingency actions have been developed and implemented.

2.3 Surveillance Activities

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 Technical Specifications, approved procedures, and NRC regulations.

The following surveillance tests were reviewed with portions witnessed by the inspector:

Procedure No.	Test
617.4.001	Control Rod Drive Pump "A" Operability Test
645.6.003	Fire Hose Station, Hose House and Fire Hydrant Inspection

A properly approved procedure was in use, approval was obtained and prerequisites satisfied prior to beginning the test, test instrumentation was properly calibrated and used, radiological practices were adequate, technical specifications were satisfied, and personnel performing the tests were qualified and knowledgeable about the test procedure.

3.0 ENGINEERING (37551, 71707, 92903)

3.1 Control Rod Drive Pump Replacement Due to Degraded Performance

On October 30, 1995, the licensee entered the limiting condition for operation in Technical Specification (TS) 3.4.D.2 for the "A" control rod drive (CRD) pump, which allows seven days of operation with one of the two CRD pumps inoperable. The rotating element was planned for replacement due to observed performance degradation. The maintenance activities were completed and the pump was satisfactorily tested on November 3, 1995, at which time TS 3.4.D.2 was exited.

During the maintenance activities licensee personnel properly identified, documented and evaluated off-normal conditions. These included 1) a localized area of erosion on the internal surface of the pump casing, 2) a slight longitudinal bow condition (0.003 inch) on the lower pump casing mating surface, and 3) the presence of an oxide coating on the rotating element and casing. The localized eroded area was repaired with a metal filler material (Belzona). The pump vendor was consulted by the licensee, and they collectively concluded that the slight bow would not present any performance or operability problems. The presence of the oxide coating was still being evaluated by the system engineer at the end of the inspection. An oxygenated water source is postulated to be related to the oxide coating.

The licensee provided substantial oversight for the CRD pump maintenance and followup. After the replacement, the licensee initially noticed a slightly lower than expected pump discharge charging header pressure (1430 psig observed vs. greater than 1450 psig expected). The system engineer developed a troubleshooting action plan to identify whether a flow diversion or incorrect throttle valve adjustment contributed to the lower than expected discharge pressure. Although no system problems were identified the system discharge pressure returned to expected values during subsequent monitoring of the charging header pressure. The plan also included actions to identify the cause for the oxide buildup, such as taking chemistry samples to determine water quality and verifying the normal CRD suction source alignment. The normal source is deaerated and heated water from the condensate demineralizer outlet header. The condensate storage tank is the backup water source, which is an oxygenated water source and more likely to introduce oxygen stress corrosion of CRD components.

By the end of the inspection period, the licensee had confirmed that the condensate demineralizer outlet water source remains a high quality water, and that there was not measurable air inleakage at the CRD pump suction line. The licensee plans to consult with an independent metallurgist to assist them in identifying the cause for the oxide coating.

The licensee's maintenance assessment organization also evaluated CRD pump performance and related problems. They evaluated the maintenance history for both the "A" and "B" CRD pumps. The data shows that when the rotating element is either rebuilt or replaced, pump performance degrades over a two year period. However, the pump and rotating element lasts about seven years if the entire pump is replaced. The licensee is continuing to assess this data.

The inspector monitored the "A" CRD pump replacement activities and the related problem assessments. The inspector concluded that the licensee's identification, documentation, and evaluation of pump performance and repair efforts were very good and demonstrated a conservative safety focus.

3.2 Notification of Reactor Protection System Design Deficiency

On October 20 and 21, 1995, two utilities notified the NRC that their reactor protection systems (RPS) could experience a condition that would prevent a full reactor scram from a "scram discharge instrument volume high level" if one relay in any one of the four RPS subsystems failed to function. The inspector questioned the licensee concerning the vulnerability of the Oyster Creek RPS to this failure mode. The licensee, after review of the reported problem, stated that Oyster Creek was not susceptible to the single failure identified in the report. The inspector independently reviewed the Oyster Creek prints and system description and verified that a single failure of a relay in the scram discharge instrument volume circuit will not result in a failure of the RPS to produce a full reactor scram. The Oyster Creek level instruments and switches (8 total, 4 North and 4 South) have a North and South switch in each of the four subsystem relay circuits such that a high level in either instrument volume will produce a full reactor scram. The utilities making the reports of the single failure condition had their level switches from each instrument volume wired in series (eg., 2 from the East or West would supply one subsystem) so that each RPS subsystem sensed one instrument volume. A failure of the subsystem relay, with a high level occurring in only one of two instrument volumes (the one sensed by the failed relay) would only produce a half-scram from the other RPS channel.

The licensee also noted that a problem had been identified in 1991, (deviation report 91-162) that would have resulted in a failure to receive either a half-scram and or an alarm due to the failure mode of the level instruments. The level instruments were physically installed such that a failure of the instrument or a loss of its power supply, would produce a signal indicating an empty (normal indication) scram discharge instrument volume (SDIV). A single failure would not have prevented a full scram because the other switches and instruments in each subsystem would still function to produce a full scram on an actual SDIV high level. This non fail-safe configuration had existed from initial design of the plant. The level instruments were modified in April and May 1991, under Job Order 30597, such that a single failure would produce an indicated SDIV high level with a reactor half-scram and alarm. The inspector also verified that a single failure of the power supplies to the level switches and/or instruments will produce a half-scram and alarm.

The inspector determined that the current RPS configuration for the SDIV high level scram fully satisfies the single failure and fail-safe design basis and that the licensee had taken aggressive action to correct the non fail-safe, silent failure design when identified in 1991.

3.3 Electrical Distribution System Functional Inspection (EDSFI) and Station Blackout (SBO) Inspection Followup

The inspector conducted a review of licensee actions to resolve four unresolved items previously identified during the EDSFI and the SBO inspections. Sufficient information was available to permit the inspector to close two of those items. In addition, one inspector follow item (IFI) was opened in the area of nuclear safety assessment (NSA) involvement in monitoring and review of the combustion turbines reliability program. The four items and the IFI are discussed in detail in Sections 5.4 and 5.5 of this report.

4.0 PLANT SUPPORT (71707, 71750)

4.1 Radiological Controls

During entry to and exit from the radiologically controlled area (RCA), the inspectors verified that proper warning signs were posted, personnel entering were wearing proper dosimetry, personnel and materials leaving were properly monitored for radioactive contamination, and monitoring instruments were functional and in calibration. During periodic plant tours, the inspectors verified that posted Radiation Work Permits (RWPs) and survey status boards were current and accurate. They 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.

4.2 Radioactive Waste and Transportation Programs

The licensee's program for solid radioactive waste and transportation of radioactive materials was reviewed. Specific areas reviewed included: processing, packaging, storing and shipping of radioactive waste and radioactive materials. The inspection also included a review of previously identified items.

4.2.1 Audits and Appraisals

Nuclear Safety Assurance (NSA) audits of the radwaste program conducted since the last radwaste inspection were reviewed. The last NSA audit of the radwaste program was conducted in June and July 1994. The auditors reported that the radwaste shipping and operations programs had been effectively implemented at Oyster Creek Nuclear Generating Station. One deviation from procedures and one minor deficiency were noted. The licensee had taken effective corrective actions for the deviation and deficiency. The auditors also noted that management attention was required due to the material condition of some radwaste system components. The inspectors verified that the material conditions had improved since the period of the licensee's audit **(see Section 4.2.4.1 of this report)**.

Vendor audits were performed periodically by the NSA staff. The inspectors reviewed the audits of two vendors performed since 1994. The audits were very comprehensive and provided good feedback to the vendors. Some findings of minor safety significance were identified and the vendors had taken prompt corrective actions to address the findings.

The licensee's NSA staff also performed eight periods of surveillance of radwaste activities in the last year. The activities under surveillance included the transfer of waste to the Low Level Radioactive Waste Storage Facility (LLRWSF), preparations for shipment of radioactive waste to the burial facility near Barnwell, South Carolina, and shipment of radioactive materials. The NSA staff had identified minor deficiencies and the licensee's staff had taken timely and technically acceptable corrective actions.

The inspectors concluded that the licensee continues to improve the quality of the radioactive waste and transportation program through the self-identification and correction of minor deficiencies. No violations of NRC regulations or major safety concerns were identified.

4.2.2 Changes in the Radwaste/Transportation Program

The licensee had made some changes in the radwaste program organization since the last NRC inspection of the radwaste and transportation programs. The program still consisted of two functional areas, the radwaste shipping program and the radwaste operations program. The Radwaste Programs Manager continued oversight of the shipping program, but the position was changed to a direct report to the Manager of Radwaste and Chemistry. The Radwaste Engineer continued oversight of radwaste operations and continued to report to the Manager of Operations. Both the Manager of Radwaste and Chemistry and the Manager of Operations reported to the Director of Operations and Maintenance.

The number of personnel supporting the Radwaste program also changed since the last inspection. The Group Radwaste Shipping Supervisors (GRWSS) continued to report to the Radwaste Programs Manager, but the number had been reduced from three GRWSS to two GRWSS. Likewise, the Group Radwaste Shift Supervisors (GRSS) continued to report to the Radwaste Engineer, but the number had decreased from 3 GRSS per shift to 2 GRSS per shift.

These changes to the radwaste and transportation programs had not resulted in any identifiable, adverse effects and no other changes to the organization were noted.

4.2.3 Training and Qualifications of Personnel

The inspectors reviewed the training and qualification of the licensee's radwaste and transportation personnel through interviews with various licensee personnel and a review of documentation. According to Department of Transportation (DOT) regulations, biennial training is required for handlers and shippers of radioactive materials.

The radwaste shipping staff and the radwaste operations staff had extensive experience in radwaste and there had not been any new supervisory personnel assigned in several years. The appropriate supervision and management had taken vendor-supplied technical training within the last two years. The station helpers that had been assigned on a rotating basis had been given hazardous material handling training in September 1993. The licensee's training personnel stated that more recent training had been given to the staff, but the latest training documentation was not available at the time of this inspection. However, the inspectors determined that the licensee was fulfilling the commitment for biennial training because the documented training was within 25% of the 24 month commitment.

In summary, training and qualifications were very good with the qualified staff contributing to the strength of the program.

4.2.4 Implementation of the Solid Radioactive Waste Program

The inspectors reviewed the implementation of the solid radioactive waste program through tours of the facility, reviews of documentation, and interviews with various licensee individuals.

4.2.4.1 Radioactive Waste Processing

The licensee used offsite vendors to process the Dry Active Waste (DAW) generated by operational activities. The licensee also used an offsite vendor to launder personnel protective clothing. Filter sludge was processed by cement solidification. Spent resins were de-watered and packaged onsite for shipping and disposal.

The inspectors toured most of the areas on the licensee's site used for processing and storing radioactive waste. Some areas were not easily accessible due to high dose rates and radioactive contamination levels, so the inspectors viewed recent photographs of those areas. The licensee performed various work in the last year to maintain the physical systems. Some areas had been decontaminated and unused tanks were drained for lay-up until decommissioning. The inspectors noted that the areas were generally very well maintained and could be accessed, if necessary. None of the areas showed significant deterioration or radiological contamination. Some areas contained equipment that had been abandoned in place, but the areas were still well maintained.

4.2.4.2 Waste Characterization

The inspectors reviewed the licensee's procedure for characterization of the radioactive waste sent for disposal. The licensee used a combination of gamma spectroscopy and scaling factors to determine the radioisotopes present in the waste stream. The scaling factors were checked by sending samples to an offsite laboratory once every two years. The licensee had developed data for various waste types including clean-up resins, waste cartridges, waste oil and sludge, DAW, and irradiated metals. The inspectors verified that the analysis data for different waste streams were current. All waste stream data had been updated in the licensee's computer software; the computer software used was the RADMAN code developed by WMG, Inc. This software has been previously verified by the NRC for use by licensees and was the subject of a topical report. In addition, the licensee's staff kept records of tests and verifications performed for all updates on all copies of the software.

4.2.4.3 Waste Storage (Closed IFI 219/94-09-01)

The inspectors reviewed an Inspector Follow Item (IFI 94-09-01) regarding the safety evaluation for operation of the Low Level Radioactive Waste Storage Facility (LLRWSF). Specifically, the inspectors reviewed the assumptions and calculations used by the licensee to conclude that there is no unreviewed safety concern for public radiation exposure as a result of normal operations or a catastrophic event such as a fire, flood, or tornado. The calculations used conservative assumptions for waste density and radioactivity of stored wastes. The resulting calculations estimated that the dose to the public from a catastrophic event would be negligible based on a total of 823 curies of radioactive waste. The licensee developed controls to limit the total activity and resulting dose rates to unrestricted areas. These controls included a dose limit of 80 millirem per hour on any DAW container, an activity limit for the cell storage areas, and activity limits for objects placed against the inside of the exterior walls of the LLRWSF. The inspectors concluded that the assumptions and calculations, along with the procedural controls were appropriate. However, the calculations may need revision in the future due to emerging technologies in waste compaction and processing. This item is closed.

The licensee had stored radioactive waste in the LLRWSF. Approximately 22 cask liners had been stored in the facility. But after the disposal site near Barnwell, South Carolina was made available to the licensee, all but 2 liners had been shipped since July 1995. The licensee plans to ship the remaining two liners to the burial site before the end of calendar year 1995. The inspectors toured the LLRWSF and viewed the DAW storage area. Since the licensee had used a vendor for processing DAW, there was no DAW stored in the facility. The inspectors noted temporary storage of radioactive materials that the licensee planned to reuse, and various 55-gallon drums with low-level radioactive soil/sand. The licensee's representative stated that the drums were stored in the LLRWSF to allow decay of the radioactive material. The inspectors concluded that the LLRWSF was used appropriately and was kept in good physical condition.

In summary, the licensee effectively implemented the solid radioactive waste program. Improvement was noted in material condition of radwaste systems. No major deficiencies or violations of regulatory requirements was identified.

4.2.5 Shipping of Radioactive Waste and Radioactive Materials

The inspectors reviewed various licensee records and observed shipment preparations to determine the effectiveness of the licensee's program. The radwaste and radioactive material shipments records that were reviewed are in listed in Table 1.

Table 1

Shipment #	Date	Type	Description	Activity (mCi)
OC-1002-95	5/5/95	RM/LSA	DAW (filters, trash)	298
OC-3004-95	10/2/95	RM/LSA	Solidified filter media	12,200
OC-3016-95	11/8/95	RM/LSA	Solidified filter sludge	21,600
OC-3008-95	6/7/95	RM/LSA	Solidified filter media	36,600
OC-4004-95	8/14/95	RM/LSA	De-watered resins	25,300

The licensee's records were kept in very good condition. Attention to detail was very good and appropriate review was performed by management. The inspectors also observed the preparations for the licensee's shipment of de-watered resins to the disposal site near Barnwell, South Carolina. The individuals involved with the shipment were very knowledgeable, maintained current training, and correctly followed the licensee's procedures for radwaste shipping. In addition, the inspectors called the emergency contact listed on the shipping papers to verify that information regarding the shipment was available to emergency responders. The licensee representative immediately provided the required information during an off-hours phone call. No violations of regulatory requirements or safety concerns were identified.

4.2.6 Radiological Controls Program Unresolved Item Followup (Closed 219/95-09-02)

Unsecured Locked High Radiation Area Door

The inspectors reviewed items that had been previously identified to determine the licensee's progress in implementing corrective actions or appropriate radiological controls. A licensee-identified incident was reported in a previous inspection (NRC Inspection 50-219/95-02) regarding ineffective high radiation area controls. A door that was posted as a locked high radiation area door was found not fully closed by a radiation protection (RP) supervisor on May 6, 1995. RP technicians immediately verified that no unauthorized personnel were inside the area, then they closed, locked, and verified the status of the door. The RP technicians also surveyed the area (condenser bay) and verified that actual dose rates were lower than the dose rates that require locked door controls (deep dose equivalent in excess of 1000 millirem per hour). Required notifications were made to supervision and management. The licensee conducted an investigation and critique and determined that two root causes contributed to this event. The first root cause was the failure of a mechanic to notify other workers after he decided to deviate from the pre-job briefing plan and the other mechanics expected him to possess the key to the locked high radiation door. The second root cause was due to multiple locked doors to the same area and the mechanics had opened one locked high radiation door from the inside without using the proper key controls.

Since the time of this event, the licensee had thoroughly investigated and analyzed the failures and implemented corrective actions. The analysis included a barrier analysis to determine where the failures in the controls occurred. Another analysis involved a human performance evaluation and completion of a causal factor work-sheet. The licensee also reviewed similar events in the past, and determined that the last similar incident had occurred on March 11, 1993. The long-term corrective actions for this event included; a review of the incident for all radiation workers, revision of the procedure to provide guidance to workers when there are multiple entrances to a controlled area, posting of warning signs on the inside of doors in areas with multiple entrances, appropriate disciplinary action for the involved individuals, and notification to site employees and other licensees regarding the event.

Due to the excellent investigation, analysis, and timely corrective actions implemented by the licensee, this violation of the licensee's procedure will not be cited consistent with Section VII of the NRC Enforcement Policy (NUREG 1600). This item is closed.

4.3 Security

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

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (71707, 90712)

5.1 Continuous Instrument Panel Power Supply Failure

During this inspection period, the licensee completed a troubleshooting plan and subsequent repairs to the primary power supply for the 120 Vac continuous instrument panel CIP-3. CIP-3 provides power for various important instruments, including the feedwater and reactor recirculation flow control systems, and ventilation and effluent radiation monitoring systems. CIP-3 is normally supplied electrical power from a rotary inverter that consists of a 120 Vac generator driven by a 480 Vac motor (normal) and a 125 Vdc motor (backup). In the event of a failure of the rotary inverter, automatic transfer switch IT-3 provides a "dead-bus" transfer from the rotary inverter to vital motor control center (MCC) 1A2.

On September 27, 1995, while operating at full power, a rotary inverter ac drive motor control fuse failed. As a result, the 125 Vdc motor began supplying the rotary inverter. The licensee was concerned about the loss of redundancy for the rotary inverter because certain equipment could be lost during the dead bus automatic transfer to 1A2 if the dc supply was to fail. The momentary loss of power to CIP-3 represented a potential for a plant transient.

The licensee developed an action plan and a procedure to determine the impact of operating transfer switch IT-3 on the reactor recirculation (RR) control system. This activity was planned to be performed during the load reduction (November 9, 1995), and was coincident with a planned activity to remove the "E" RR pump from service for maintenance. The planned activity was evaluated and documented in a 10 CFR 50.59 safety evaluation dated November 7, 1995. If it could be demonstrated that the effect of transferring CIP-3 to vital MCC 1A2 would not impact the operation of the "E" RR pump, then the licensee would perform the transfer and repair the failed ac fuse.

The procedure was conducted on November 10 in accordance with the approved action plan. The results indicated that during a transfer to vital MCC 1A2, one or more RR pumps would trip, thereby creating an undesirable plant transient. The action plan was exited as designed, and the efforts to place the CIP-3 power supply to 1A2 were canceled.

However, subsequent to the above efforts, on November 11, electrical perturbations were observed for the rotary inverter. The licensee found water inleakage (during a severe rain storm) on CIP-3, which was the cause for the electrical perturbations.

Operations personnel immediately initiated several efforts, including drying off the CIP-3 panel, attempting to stop the inleakage, and reviewing the previously completed action plan for the possible loss of the rotary inverter and CIP-3. Conditions were stabilized without incident, however, station management redirected station personnel to correct the rotary inverter ac motor while being powered by the dc motor (vice transferring to 1A2).

Repairs were successfully completed to the ac control circuit and panel on November 12, 1995, using job order 500906. The rotary inverter was then shifted to the ac drive, and the CIP-3 system was restored to normal configuration. Subsequent repairs were made to seal the source of water intrusion to the building.

The inspector monitored the licensee's efforts related to evaluating the configuration of CIP-3, and the associated troubleshooting and repair plans. The licensee was sensitive to the potential impact that possible rotary inverter and CIP-3 failures would have on the plant. The inspector concluded that the licensee's efforts were conservative and were well planned and executed.

5.2 Reactor Recirculation Control System Fluctuations

Throughout this operating cycle (January 1995-present), occasional flow and speed oscillations on the reactor recirculation (RR) system were observed by control room operators. During the Fall 1994 15R refueling outage, the licensee replaced a portion of the RR control system as part of a digital upgrade. That modification was expected to prevent or minimize existing problems with the installed analog system. However, the flow and speed oscillations, as well as associated core thermal power changes, continued to occur.

In response to the continuing minor fluctuations, the licensee developed and documented a formal action plan to collect data and analyze the RR control system. The plan was to be implemented during the November 9, 1995, downpower. A risk assessment and a safety determination were completed to review the planned activities.

During the downpower, the licensee collected data for analysis. No obvious causes for the problems were apparent. An offsite contractor is expected to independently evaluate the data in an attempt to identify potential problems.

The NRC Region I, Division of Reactor Safety discussed the concerns related to the RR control system with licensee engineering personnel on November 28, 1995. Although no root causes have been identified to date, the licensee believes equipment that was not replaced during the digital upgrade is causing input problems/fluctuations to the digital system; the digital control system appears to be responding correctly. Control room operators have been alerted to the possible system responses and associated corrective actions such as taking manual control and reducing reactor power. The power changes (in either direction) have been relatively small (less than 10 MW_t); no reportable conditions resulted.

The inspector concluded that the licensee efforts have been appropriately focused on identifying causes to the RR control system fluctuations. Station, operations and engineering management were providing strong oversight for this issue. The troubleshooting action plan, and the associated risk and safety evaluations were of high quality. The inspector concluded that the licensee's overall followup for this issue was very well planned and conservative.

5.3 Licensee Event Report (LER) and Periodic Report Review

The inspectors reviewed the following LERs and periodic reports and verified appropriate reporting, timeliness, complete event description, cause identification, and complete information. In addition, the inspectors assessed the LERs to determine whether further onsite review was needed.

Licensee Event Reports

- LER 95-05 discussed a non-conservative setpoint of the anticipatory reactor scram bypass switches due to an original design deficiency. The licensee lowered the affected pressure switch setpoints to a conservative value consistent with design basis assumptions. This event was discussed in detail in NRC Inspection 50-219/95-15. This LER is closed.

- LER 95-06 described inoperable emergency lighting units (ELU) that were required to be functional to meet 10 CFR 50 Appendix R requirements. The five Appendix R ELUs were repaired and returned to service; and enhanced programmatic controls were instituted to prevent similar occurrences. This issue was reviewed and documented in NRC Inspection 50-219/95-16. This LER is closed.

- LER 95-07 documented a missed quarterly surveillance test to stroke the scram discharge volume vent and drain valves. The affected valves were promptly tested satisfactorily upon discovery, and a complete review of the surveillance test program was initiated by a task group to identify whether a programmatic problem contributed to this event. This event was documented in NRC Inspection 50-219/95-16. This LER is closed.

The quality and content of each of the above LERs were generally good. However, each LER contained relevant weaknesses. Specifically, LER 95-05 failed to identify that the licensee's completed review of the industry notification letter for this issue was delayed for about ten years (due to inadequate turnover of program responsibility). LER 95-06 failed to identify the magnitude and nature of the ELU failures. Although many of the ELU failures were not Appendix R units, over 300 battery failures occurred since 1989. In addition, both design and manufacturing problems contributed to the many battery failures. The stated root cause for the missed surveillance in LER 95-07 was overly general, and did not reflect contributing causes such as personnel errors resulting from inattention to detail.

The inspector discussed these LER quality and content weaknesses with licensee management, who acknowledge the concerns.

Periodic Reports

- Monthly Operating Report for the months of September and October, 1995.

5.4 Review of Previously Opened Items

(Closed) Unresolved Item 50-219/95-15-02: Determine Safety Significance of Non-Conservative Setpoint.

This item was related to an evaluation to determine the safety significance of a non-conservatively adjusted turbine trip reactor scram bypass setpoint. The licensee defined a particular range of vulnerability (40% to 50% reactor power) to evaluate the absence of the anticipatory trip. The postulated transient evaluation was performed using an approved transient model computer program. The results indicated that the fuel cladding integrity safety limits would not have been exceeded (using conservative assumptions). Therefore, the safety significance of this event was low. In addition, redundant reactor protection system automatic scrams exist to provide added margin to the fuel cladding integrity safety limits. Based upon the licensee's completion of this evaluation, and the associated low safety significance of the postulated event, no further action for this operation is necessary. Corrective action to restore the setpoint to a conservative value was previously completed. This item is closed.

(Closed) Unresolved Item 50-219/94-01-01: Adequacy of Design Voltage to Safety-Related Components Under Degraded Grid Voltage Conditions.

During the followup EDSFI inspection and other routine inspections in 1993 and 1994, the inspectors noted several voltage-related concerns with the plant equipment. During January 3-7, 1994, an NRC electrical issues followup inspection, 50-219/94-04, determined that the licensee actions, taken to administratively control the required grid voltage to assure emergency bus voltage above 4100 Vac or higher for plant operation, were appropriate interim measure until the degraded grid voltage concerns were fully addressed. Therefore, Unresolved Item No. 94-01-01 was opened to track this degraded bus voltage concern.

During a followup inspection on this issue, conducted from November 14, 1994, to November 18, 1994, and documented in NRC Inspection Report 50-219/94-27, the inspector noted that the licensee had completed several evaluations of the electrical distribution system, had completed a safety evaluation (SE-0('731-002), and had submitted a Technical Specification Change Request (TSCR No. 219). The licensee's SE stated that, based on their electrical system reanalysis, the existing degraded voltage relay setpoint may not adequately protect all the safety functions of all equipment. Based on their electrical system reanalysis, the licensee determined that a more appropriate degraded voltage relay setpoint would be at 3840 Vac, instead of the existing

3671 Vac. The SE also states that additional modifications and/or additional analyses were required to bring the remaining equipment up to an acceptable level.

During this inspection, the inspector reviewed the licensee's comprehensive design report addressing these concerns, and selected supporting calculations and other supporting document changes. The inspector determined that appropriate calculations had been completed and modifications implemented to ensure adequate voltage would exist at all safety-related components powered from the offsite supply. The inspector confirmed the degraded voltage relay setpoint had been increased and the setpoint agreed with the Technical Specification. The inspector verified Station Procedure 317, "Feedwater System," and Procedure 336.1, "24 kV Main Generator," had been changed to support the potential degraded voltage condition. The inspector had no further questions. This item is closed.

(Open) Unresolved Item 50-219/95-05-01: Diesel Generator Reliability Program

At the time of their original station blackout (SBO) submittal, GPUN stated that the target reliability was based on the last 100 demands on each diesel generator, but provided no data to support the statement. Therefore, in their August 26, 1991, safety evaluation report (SER), the NRC requested that the licensee confirm that a reliability program meeting the guidance of NRC Regulatory Guide (RG) 1.155, "Station Blackout," Revision 0, Position 1.2, for the emergency diesel generators (EDG) was or would be implemented.

During a previous NRC inspection (50-219/95-05), the inspector discussed with GPUN engineering the status of the EDG reliability program requested by the NRC in the SER. The inspector observed a formal reliability program had not been established. However, the licensee stated that they were reviewing RG 1.9, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units," Revision 3, to determine whether programmatic changes to the testing of the EDGs were necessary. The inspector concluded that the EDGs reliability was not an immediate concern. The licensee's ability to maintain a 4-hour SBO coping duration remained unresolved pending their formalization of an EDG reliability program that met the recommendations of the NRC SER, and assured the targeted EDG reliability factor. A reliability factor of 0.95 was the basis for the SBO coping duration.

During this inspection, the inspector confirmed the formal program to monitor the EDG reliability factors in support of the SBO rule had still not been developed. A licensing internal planning schedule had an anticipated completion date of December 30, 1995. During the exit meeting on November 9, 1995, GPUN management stated that the program would be implemented by February 28, 1996. In addition, the licensee indicated that diesel engine analysis equipment would be installed during 1996 to further enhance the diesel performance monitoring program. This will remain an open item pending the licensee's implementation of the formal EDG reliability program to support their SBO submittal and its subsequent NRC review.

(Open) Unresolved Item 50-219/95-05-02: Combustion Turbine Reliability Program

A previous NRC inspection (50-219/95-05) questioned the reported high reliability of the Forked River Combustion Turbines (CT) because reliability reported during 1994 did not account for the unavailability of the CT units to support a SBO due to a configuration change implemented by JCP&L.

During this inspection, the inspector verified GPUN had revised the CT reliability records to indicate the unavailability of the CTs during that time when the gas sensor interlock prevented the CTs from responding to a black start. Adequate corrective actions are now in place to control CT configuration changes that might affect their SBO response.

The Oyster Creek SBO submittal was based on the Nuclear Management and Resources Council document NUMARC 87-00, Revision 1, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors." Appendix I of that document indicates when a peaking unit is being used as an alternate ac source, reliability and not availability is the appropriate parameter to use. However, the Oyster Creek SBO submittal was based on a combined reliability of both CTs providing a 95% system reliability factor because the individual reliability factors were only 93%; therefore, Oyster Creek requires both CTs to be available or the reliability of one CT above 95%. The inspector reviewed the CT reliability program and found that it still did not account for unit availability of the CTs. The inspector observed that the entries in the control room log indicated one of the CT units was unavailable for three days during October 1995. In response, the licensee indicated that JCP&L has informed them that the "unavailable" unit could have been switched over to fuel oil. The inspector reviewed the JCP&L log and confirmed the problem was with the normal gas supply.

Because Oyster Creek requires both CTs to maintain a system reliability of 95%, this item will remain unresolved pending NRC review of the licensee's resolution of their CT reliability program to account for CT availability.

(Closed) Unresolved Item 50-219/95-05-03: GPUN-JCP&L Interface Agreements Addressing the FRCTs and Support for Station Blackout

During a previous NRC inspection (50-219/95-05), the inspector observed that additional work was necessary to strengthen the interface between GPUN and JCP&L. The inspector observed that no formal requirement had been imposed to ensure that interface meetings would take place and be documented. Also, the responsibility of the GPUN system engineer regarding the SBO equipment under JCP&L jurisdiction had not been clearly defined. Thus, it appeared that the decision on when or whether to perform a safety evaluation for a proposed modification rested solely on the GPUN system engineer.

During this inspection, the inspector confirmed a pre-existing memorandum of understanding between the two companies had been clarified to specifically address the JCP&L/Forked River support for Oyster Creek SBO. An Oyster Creek system engineer had been assigned as the station's point of contact for SBO-related activities. In addition, a System Performance Team, consisting of the Oyster Creek system engineer, the Forked River Combustion Turbine site engineer and an Oyster Creek shift supervisor, was formed to conduct a formal, quarterly review meeting. The inspector reviewed the notes from the recent SBO interface meetings. The inspector noted attendance by other members from both companies. Oyster Creek Nuclear Safety Assurance personnel also audited the meetings to assess their effectiveness. The inspector concluded that sufficient intercompany attention and interface now exists to avoid future configuration change problems with the CTs that could affect their SB response without GPUN knowledge. This item is closed.

5.5 Nuclear Safety Assessment Involvement in the Combustion Turbine Reliability Program (IFI 50-219/95-22-01)

NUMARC 87-00, Appendix B, Criteria B.11, requires a maintenance program for the alternate ac system that considers manufacturer's recommendations or that is in accordance with plant-developed procedures. In their submittal to the Station Blackout (SBO) rule, GPUN had not addressed the Quality Assurance (QA) program for the SBO equipment. Therefore, the NRC concluded that GPUN should verify that the equipment was covered by an appropriate QA program. GPUN stated that the SBO equipment would be classified and included in an appropriately graded QA program, consistent with the guidance RG 1.155.

The SBO equipment at Oyster Creek is nonsafety-related and some components, such as the combustion turbines (CT), are outside the direct control and responsibility of GPUN. In a previous NRC inspection (50-219/95-05), the NRC's review of this area confirmed that the components within the direct control of GPUN had been included in the station QA plan. However, the CTs are owned and operated by Jersey Central Power and Light (JCP&L) and are operated as peaking units. The units were provided as a complete package as a "turn-key" project from General Electric.

During this inspection, the inspector found that Station Procedure 117.3, "Combustion Turbine Reliability," required a QA review of the CT reliability program. That procedure listed specific items to review, including CT reliability and CT maintenance. The inspector noted that the licensee's QA organization, the Nuclear Safety Assessment Group, did not appear to have performed any reviews in these specific areas.

JCP&L is responsible for the maintenance on the CTs and has, in the past, had the manufacturer perform the major maintenance. JCP&L has provided GPUN with two sets of manuals for the CTs and their supporting systems. They also provided the Oyster Creek SBO systems engineer with a list of periodic maintenance performed and a list of major maintenance scheduled for 1995 and 1997. No major maintenance had been scheduled for 1996 at the time of this inspection.

The inspector reviewed the JCP&L maintenance list and compared it to the information provided in the manufacturer's manuals. The inspector selected specific auxiliary components that are required to start the CTs to perform an independent assessment of maintenance practices that could affect unit reliability. The inspector noted two areas of maintenance that appeared weak.

The CTs are started with a diesel engine which brings the CT up to firing speed. The inspector observed that the manufacturer's manual calls for maintenance on the diesel every 90 starts or annually. JCP&L schedules this maintenance annually and is usually performed in the spring. The inspector noted that the No. 2 CT had 108 starts in 1995, without maintenance being performed on the diesel.

The diesel engine is started by a dc electric motor powered by a battery dedicated to its CT. The inspector also observed that the list of JCP&L

battery maintenance consisted of a monthly check of water level and an annual check of specific gravity. The inspector noted that the battery manufacturer's instruction booklet included in the CT manuals indicated batteries used in diesel start applications would also require periodic equalizing charging. Equalizing charges were not included on the JCP&L maintenance list provided to the Oyster Creek SBO system engineer.

Following the inspection, the licensee provided information indicating their intentions to periodically monitor the CT reliability program, including the GPUN/JCP&L agreements surrounding the use of the CTs, their reliability and their maintenance. This also included a draft audit scope of the Nuclear Safety Assessment Group plans, to be implemented in March 1996, to review this area. This will be an Inspector Follow Item pending a future NRC review of the depth of Nuclear Safety Assessment's involvement in monitoring the CT reliability program. **(IFI 50-219/95-22-01)**

6.0 EXIT INTERVIEWS/MEETINGS (71707)

6.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the senior licensee management on December 4, 1995. 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.

The inspection consisted of normal, backshift and deep backshift inspection; 29.5 of the direct inspection hours were performed during backshift periods, and 2 of the hours were deep backshift hours.

6.2 Attendance at Management Meetings

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

Date	Lead Inspector	Subject	Report No.
November 2, 1995	L. Eckert	Emergency Preparedness Exercise	95-20
November 17, 1995	H. Gregg	Service Water Self-Assessment	95-17

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