U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	93-29
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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 12, 1993 - January 23, 1994
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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 delineates the inspection findings and conclusions.

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EXECUTIVE SUMMARY

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Plant Operations

GPUN operated the unit safely. The licensee responded promptly to address the two operability issues that occurred during this inspection period. The "D" EMRV was declared inoperable when the valve reset switch functioned in a slightly erratic manner during a surveillance test. The switch was repaired and the EMRV was returned to service. Prompt action was taken by control room operators to verify the operability of the safety function of the rod control system when it was identified that control rods would not move with the manual control switch.

Maintenance

The maintenance and surveillance activities observed were generally conducted safely by knowledgeable personnel. However, one personnel error resulted in an inadvertent actuation of core spray (CS) system No. 1 and the No. 1 emergency diesel generator (EDG) during surveillance testing. The licensee properly reported this event and took appropriate corrective personnel actions. The event was characterized as a non-cited violation.

Troubleshooting activities conducted in support of emergency service water (ESW) surveillance testing identified a blockage in the high side sensing line of the flow transmitter. Problems with ESW flow indication have been ongoing; however, the ESW system successfully passed the flow test on the first attempt subsequent to clearing the sensing line. The licensee's troubleshooting activities have been deliberate with a good safety perspective.

Engineering

Corporate engineering identified that the core spray system No. 1 minimum flow line weakest weld could exceed the design code stress limit. This was reported to the NRC per the 10 CFR 50.72 requirements; however, the report was delayed several days while further information was gathered to make an operability determination. The licensee's analysis determined that the weld might deform but would maintain integrity and system operability. This issue is an unresolved item pending further NRC review. Site engineering personnel performed a good engineering evaluation to address the installation of a cover and band clamp device to stop a steam leak on the 1-1 main flash tank manway.

Plant Support

Periodic observation of station worker and radiological controls personnel by the inspectors noted good implementation of radiological controls program requirements. Physical security program requirements were being effectively implemented.

Safety Assessment/Quality Verification

Inspectors noted during the observation of two plant review group (PRG) meetings that the group reached appropriate decisions based on the numerous questions discussed; however, the questions appeared, to a small degree, to support or lead toward the desired recommendation. Licensee event reports (LER) were in general technically adequate and complete. Licensee actions and preplanning activities during the cold weather power emergency were thorough and addressed both risk and safety considerations of the plant and the electrical grid.

DETAILS

1.0 PLANT OPERATIONS (71707,93702)

1.1 Operations Summary

The unit operated at or near full power during the inspection period, except for a power reduction to about 67 percent for five days to replace the C main condensate pump and clean main condenser tubes.

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

Control room activities were found to be well controlled and conducted in a professional manner. The inspectors verified operator knowledge of ongoing plant activities, equipment status, and existing fire watches.

1.3 Operability Review for Electromatic Relief Valve

On January 13, 1994, the "D" electromatic relief valve (EMRV) was declared inoperable due to a surveillance test failure. During conduct of surveillance procedure No. 602.3.004, "EMRV Pressure Sensor Test and Calibration," the "D" EMRV reset contacts were not functioning in a step manner. The function of the EMRV reset contacts is to break the control circuit continuity and close the associated EMRV. The EMRV is opened by separate (high) contacts, which were determined to be operable. Both sets of contacts are integral to the EMRV switch assembly.

The reset for the "D" EMRV is required to actuate between 1019.5 psig and 1024.5 psig per surveillance procedure acceptance criteria. During the test, the observed range was between 1009 psig and 1023 psig; the contacts actuated on each attempt, however, its operation was not in a step manner or repeatable. The Acceptance Criteria section of the surveillance procedure listed both the high switch setpoint and the reset switch setpoint for considering the associated EMRVs operable.

Due to the failure of the "D" EMRV reset switch, the licensee declared the valve inoperable at 3:00 p.m. on January 13, 1994. The Limiting Condition for Operation listed in Technical Specification (TS) 3.4.B allowed continued operation with four of the five EMRVs operable for three days. The licensee could not locate a qualified replacement switch in the warehouse. They then initiated several actions, including 1) ordering a new switch (expected delivery - about one day); and 2) evaluating the EMRV function to determine whether the function of the switch reset actually impacts EMRV operability.

An engineering evaluation was completed on January 14, 1994, to assess the operability of the "D" EMRV. Operations management stated that they were going to consider the EMRV to be operable because 1) the safety function for the EMRV pressure relief mode of operation is to open; 2) there is reasonable assurance that the EMRV will close; 3) procedures are in place and operators are trained to mitigate the consequences of a failed open EMRV; and 4) the TSs do not specify an EMRV closing setpoint, while the open setpoint is specified. A Plant Review Group (PRG) meeting was convened on January 14, 1994, to independently evaluate the concern. The PRG concluded that the "D" EMRV can be considered operable (See Section 5.1 of this report for additional discussion of the PRG meeting).

Coincident with the PRG meeting on January 14, 1994, licensee maintenance technicians were troubleshooting the installed pressure switch on the "D" EMRV. The licensee had suspected that the problem was related to oxidation buildup on the reset contacts. The technicians connected an external power supply to the contacts in an attempt to remove the oxidation. The repair was successful, as the reset function was subsequently retested satisfactorily. The associated TS Action Statement was exited on January 14, 1994, at 5:00 p.m.

The inspector reviewed the licensee's followup for this concern, and concluded that GPUN adequately addressed the safety issues. However, the inspector determined that while this particular event was resolved (by repairing the installed switch), additional permanent corrective actions should be considered to preclude a similar challenge to the station staff.

1.4 Inoperable Control Rod Manual Control Switch

On January 9, 1994 (at 2:40 a.m.), while performing surveillance procedure No. 617.4.002, "Control Rod Drive Exercise and Flow Test," the control room operators noted that the control rods would not move via the manual control switch. Control room operators immediately attempted to insert a single control rod using the "emergency-in" switch; the control rod functioned satisfactorily. Consistent with an operability evaluation previously completed by the licensee for the reactor manual control system (See NRC Inspection 50-219/92-25), the control rods were not declared inoperable because the licensee concluded that both the emergency insertion and control rod scram capabilities remained unaffected, thereby ensuring control rod operability per Technical Specifications. During the troubleshooting activities, the licensee confirmed that a timer associated with the manual control switch was the cause for the problem. The timer was subsequently repaired, and the rod control system was satisfactorily tested at 1:28 p.m. that same day. The inspector concluded that the licensee responded appropriately to this event.

2.0 MAINTENANCE (62703,61726)

2.1 Maintenance Activities

The inspectors observed selected maintenance activities on 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 inspectors reviewed the following job orders/work requests and observed portions of their associated activities.

Job Order (JO)/ Work Request (WR)	Description
JO 51036	Troubleshoot the trip of "C" recirculation pump and repair as required.
JO 51458	Perform preventive/corrective maintenance on diesel generator No. 1.
JO 51610	Perform preventive/corrective maintenance on diesel generator No. 2.
WR 763174	Support troubleshooting of ESW system 1 flow instrument problem.
JO 51847	Replace "C" condensate pump and motor

2.2 Surveillance Observation

The inspectors performed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. The inspectors verified that the surveillance tests were performed in accordance with Technical Specifications, approved procedures, and NRC regulations.

The inspector reviewed the following surveillance test and witnessed portions of the test performance:

Procedure No.	Test
607.4.004	Containment Spray and Emergency Service Water System 1 Pump Operability and Inservice Test

The test was satisfactorily completed on January 4, 1994. During past performances of this surveillance procedure, the licensee has experienced difficulty meeting the 3400 gpm emergency service water (ESW) flow acceptance criterion. The "Annubar" flow sensing element has been suspect in past tests and was cleaned when flow did not reach 3400 gpm. Cleaning usually helped somewhat. During the last surveillance on December 9, 1993, cleaning did not help. As discussed in NRC Inspection Report 93-27, during system evaluation and troubleshooting, the indicated system flow increased as the system was allowed to run for an extended period of time. The ESW system successfully passed its surveillance test on December 9, 1993, and was declared operable. No physical problem could be identified by the licensee during troubleshooting activities. Prior to performance of the test on January 4, 1994 test, the licensee flushed the differential pressure instrument sensing lines. When the high side instrument sensing line for system No. 1 was flushed, the pressure required to flush the line increased initially and then decreased to a lower value, indicating that the line had an obstruction that was flushed out of the sensing line. When the system was tested, FSW flow met the acceptance criteria on the first attempt and did not exhibit any abnormal flow characteristics.

The inspectors noted that 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.

2.3 Inadvertent Engineered Safety Feature (ESF) Actuation Due to Personnel Error

On December 3, 1993, while operating at 100% power, an inadvertent actuation of core spray (CS) system No. 1 and the associated No. 1 emergency diesel operator (EDG) occurred during surveillance testing. During performance of surveillance test procedure No. 610.3.105, "Core Spray System No. 1 Instrument Channel Calibration, Test and System Operability," maintenance technicians inadvertently pulled fuses for CS system No. 2, rendering that system inoperable. When other maintenance technicians involved with the test performed the first sensor check on CS system No.1 (reactor vessel low-low water level sensor), that system automatically initiated, and the No. 1 emergency diesel generator (EDG) automatically started and idled, as designed. CS system No. 1 did not inject into the reactor vessel because reactor pressure was greater than the CS system discharge pressure of 350 psig. Control room operators promptly recognized and responded to the inadvertent ESF actuation.

Immediate corrective actions taken by the licensee included restoring CS system No. 1 to normal configuration. The CS system No. 2 fuses were replaced, and the system was satisfactorily tested to demonstrate operability.

The licensee reviewed this event and determined that the root cause was "inattention to duty." In all, six maintenance technicians were assigned to perform the surveillance test. On December 2, 1993, the technicians were preparing to test CS system No. 2 (which included reviewing the CS system No. 2 test procedure), however, the surveillance test was deferred (until December 4) due to planned maintenance on the system. Then on December 3, CS system No. 1 was scheduled for operability testing in support of the upcoming maintenance on CS system No. 2. Four of the six technicians assigned to conduct the December 3 CS system No. 1 surveillance test had reviewed the CS system No. 2 surveillance procedure the previous day. When the two technicians were requested to perform the specific procedure steps (remove fuses), they left the maintenance shop with the CS system No. 2 surveillance procedure that was left from the previous day instead of the correct system No. 1 procedure. As a result, they removed the CS system No. 2 fuses (the action steps to remove the fuses for each CS system test are numbered identically).

The inspector reviewed this event and the associated licensee's followup activities. The inspector determined that one of the two CS systems remained operable throughout this event. In addition, the maximum average planer linear heat generation rate (MAPHLGR) was less than 90% during the time that CS system No. 2 was inoperable, per Technical Specification requirements. The licensee properly reported this event in accordance with 10 CFR 50.72 and 50.73 reporting requirements. Additional planned licensee actions include 1) conducting discussions with the appropriate maintenance personnel concerning the need to properly control all copies of surveillance procedures, and 2) incorporating a critique of this event into the maintenance technician training program. The inspector also identified possible communication weaknesses that contributed to this event.

The inspector concluded that the licensee's response to this event was appropriate. The failure to properly execute surveillance procedure No. 610.3.105 constitutes a violation of Technical Specification 6.8.1, which requires that procedures be established and implemented. However, this incident was of low safety significance, and the corrective actions were prompt and appropriate. In addition, this was not a violation that could reasonably have been expected to be prevented by any corrective actions taken for previous violations. For these reasons, this violation is not being cited as provided in NRC Enforcement Policy, Appendix C (1993) to 10 CFR Part 2.

3.0 ENGINEERING (71707,40500)

3.1 Core Spray System Piping Stress Exceeds Current Design Basis (UNR 50-219/93-29-01)

On January 15, 1994, the licensee reported to the NRC that an engineering analysis determined that the core spray (CS) system No. 1 minimum flow line could exceed its design code stress limit. The report was made per the reporting requirements of 10 CFR 50.72.

The CS system was being analyzed in support of a proposed modification to install a loop seal in the minimum recirculation flow line. Engineering personnel identified two concerns: 1) the existing configuration did not meet the ASA B31.1 Code for Pressure plus Deadweight plus Seismic requirements; and 2) the existing configuration exceeded the ASA B31.1 Code Thermal Expansion requirements.

The inspector reviewed the associated documentation. On January 10, 1994 (at 9:00 a.m.), a Deviation Report (DR) was initiated, documenting the concern. The report stated that the piping exceeded the allowable values in the UFSAR. The DR was signed on January 13. An operability determination, confirming that the integrity of the pipe would be maintained, was completed on January 14. Then, on January 15, the licensee reported this event to the NRC at 11:13 a.m. The inspector concluded that the required 10 CFR 50.72 report was delayed until January 15, while sufficient information appeared to have been available since January 10.

The inspector reviewed the associated operability assessment and did not identify deficiencies. The assessment concluded that under worst case conditions, the pipe is not expected to fail, though it may deform. In addition, using seismic spectra that was recently submitted to the NRC for approval, the licensee concluded that the existing configuration was acceptable. The planned modification will increase the piping flexibility to address the thermal expansion concern, and will provide appropriate supports for system valves to resolve the seismic concerns. CS system No. 2 is currently being evaluated, although preliminary assessment indicated that system No. 1 configuration was more severe.

The inspector concluded that, although the licensee's initial actions were slow to formally report the event, the interim actions were appropriate. This issue is currently being reviewed by NRC specialist inspectors. Pending completion of this review, this item is unresolved. (**UNR 50-219/93-29-01**).

3.2 Leak From Main Flash Tank 1-1 Manway

During the inspection period, the licensee had been monitoring a steam leak from the manway flange on one of the two main flash tanks (No. 1-1). An enclosure was constructed by a contractor (Team, Inc.), which encapsulated the manway area and was held in place with five band clamps. Sealant was to be injected into two grooves around the perimeter of the enclosure (between the enclosure perimeter and the tank outer surface). Sealant was injected by a second contractor (Leak Repair). The initial injection was unsuccessful in that the leakage did not stop.

The licensee subsequently elected to inject a more viscous sealant, this time into the center of the enclosure (between the enclosure and the tank manway cover). While the second injection initially appeared to be more effective, it again failed to stop the leak. A third and final attempt was planned to fill the remainder of the void, except for about 10 cubic inches. This injection was to utilize a two part epoxy that did not require heat to cure or compression to fill the void. The third attempt successfully stopped the leak.

The inspectors monitored the licensee's progress of repairing the leaking flash tank manway flange. Several engineering evaluations were completed by the licensee, which considered impact of the planned activities on such items as the seismic integrity of the tank, the integrity on the manway cover, and personnel hazards. The inspector found that the engineering evaluations were acceptable. The types of sealants had been used on previous occasions at the facility. The sealants are proprietary, however, the licensee does have certification of the content of certain ingredients such as fluorides, chlorides, sulfates, soft metals, etc., so that evaluations could be made to assess the impact of intrusion into plant systems. Past use of the sealants had not presented any problems. Use of sealant this time resulted in an increase in off-gas radiation monitor readings which was ultimately attributed to a component in the sealant (Carbon 12 became Nitrogen 13 when activated in the reactor core) used in one of the injections (see Section 5.1 of this report for related discussion). The inspector did not identify any significant concerns, and will continue to review related repair activities during future routine inspections.

4.0 PLANT SUPPORT (71707)

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 extended Radiation Work Permits (RWPs) and survey status boards were current and accurate. The inspectors 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 Security

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

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (40500, 90712, 90713, 92700, 92701)

5.1 Plant Review Group Meetings

The inspectors attended two Plant Review Group (PRG) meetings during this inspection period. One meeting on January 11, 1994, discussed an unusual (not previously observed) increase in air ejector radiation monitor readings when transferring high purity water to the main condenser. Plant chemistry had determined the reason for the increase to be Nitrogen 13, an activation product of Carbon 12 which entered the radwaste stream via the 1-4 sump. The leakage into 1-4 sump contained components of a propriety sealant dissolved by a steam leak on the flash tank which was being directed to the sump. The second meeting on January 14, 1994, discussed the operability of an electromatic relief valve when its reset switch (the pressure that the valve would close after lifting) displayed a slightly erratic setpoint. The inspectors noted that the decisions (recommendations to management) reached were technically justified by the facts. The inspectors also noted that the questions asked by the PRG in both meetings although extensive, appeared to a small degree, to support or lead to the desired recommendation. The inspectors will continue to attend and observe PRG meetings on a routine basis during future routine inspections.

5.2 Licensee Event Report (LER) and Periodic Report Review

NRC inspectors reviewed the following LERs and periodic reports, and verified appropriate reporting, timeliness, complete and accurate event description and cause identification. In addition, the need for on site review was assessed. The following reports were reviewed.

Licensee Event Reports

- LER 90-05, Revision 1, identifies the cause of a loss of power to unit substation (USS) 1B2. The original LER described the event but did not identify the cause of the cable failure. The revised LER stated the cause of the failure was a void in the insulation of the cable, which led to a short circuit to ground causing the supply breaker to USS 1B2 to trip. A representative sample of cables supplying other safety related equipment was also tested. No generic concerns were identified. This event was described in NRC Inspection 50-219/91-07. This LER is closed.

- LER 92-14 (Revision 1) was submitted to document the results of an investigation to determine the effects on the secondary containment of a hole in the service water (SW) system, located inside the reactor building (RB). The initial LER was submitted on January 19, 1993. The licensee determined that although the service water discharge piping is a low pressure area and draws RB air into the discharge piping the consequences were minimal and it was not an unmonitored release. The service water discharge is monitored continuously or sampled daily. This LER is closed.

- LER 93-04 (Revision 1) addresses changes to an LER that discussed a potential torus condition outside the design basis of the plant. See Section 5.4 of this report for further discussion on this issue. This LER is closed.

- LER 93-06 described a concern in which the plant was operated outside its design basis during surveillance testing. Specifically, the maximum average planar linear heat generation rate (MAPLHGR) was greater than 90% with one of the two core spray systems inoperable, a condition prohibited by station Technical Specifications. This event is described in detail in NRC Inspection Report No. 50-219/93-81. This LER committed to submitting a supplemental report (expected date - March 31, 1994) to discuss the results of a related procedure review. The current LER accurately describes and assesses the event. This LER remains open, pending submission of the supplemental report.

- LER 93-07 described the licensee's failure to perform a Technical Specification required surveillance test for a portion of the average power range monitor trip system. This event was described in detail in NRC Inspection 50-219/93-27. This LER is closed.

- LER 93-08 discussed an inadvertent engineered safety feature actuation that occurred during surveillance testing (due to personnel error). The inspector reviewed this event as described in Section 2.3 of this report, and closed this LER.

Periodic Reports

- Monthly Operating Reports for November and December, 1993

5.3 Potential Station Impact from Adverse Weather Conditions

During the week beginning January 16, 1994, extreme winter weather conditions presented challenges to station personnel. There was a combination of rain, snow and extreme cold conditions. In general, the outside plant components, such as emergency service water and circulating water pumps performed acceptably during the extreme conditions. Specific problems were properly resolved by station personnel. In summary, overall station operations coped well with the adverse weather conditions.

Due to the combination of the extreme weather conditions and several electrical power generation facilities being out of service, several geographical areas along the eastern coast experienced problems supplying the increased electrical demands. Several areas initiated planned periodic "blackouts" of sections of the electrical grid in an attempt to maintain them in a stable condition. GPUN reviewed station surveillance testing and maintenance activities to prevent or delay the performance of "high risk" activities that could possibly result in a unit trip.

Several Technical Specification (TS) required surveillance test activities were identified as high risk activities. Where appropriate, the licensee extended the test interval to include the allowed 25% tolerance (per Tss). GPUN informed the inspectors of one specific test which intentionally actuates half-scrams. The possibility of enforcement discretion was discussed on January 21, 1994. The surveillance test was due to be performed on January 23, 1994. The electrical grid "emergency" condition was terminated on January 22, 1994, and the licensee elected not to pursue discretionary enforcement. During the week, the licensee also did not perform any high-risk planned maintenance activities.

The inspector concluded that the licensee effectively and proactively evaluated station activities from a risk and safety perspective.

5.4 Review of Previously Opened Items

(Closed) Unresolved Item 50-219/93-09-01

This item was identified after the licensee could not verify the existence of reactor building blowout panels. The UFSAR (Section 6.2.3.2) stated that the reactor building was designed to relieve pressure at 0.25 psig internal pressure, accommodated by blowout panels located above the 119 foot elevation of the building. This item was reviewed and updated in NRC Inspection 50-219/93-11. At that time, the inspector concluded that the calculations performed to assess the effects of the higher post high energy line break (HELB) pressures and temperatures on reactor building structures and equipment were done in accordance with established guidance and applied appropriate levels of conservatism. Those calculations, along with other design documentation, indicated that the reactor building would relieve pressure at 0.95 psig, due to failure of the reactor building siding. Licensee Event Report (LER) No. 93-04, dated July 1, 1993, appropriately described the event and the associated assessment.

By letter dated December 23, 1993, the licensee submitted Revision 1 to LER 93-04. That document noted that this event was subsequently determined to be not reportable, as final calculations have demonstrated that the reactor building siding will relieve pressure at 0.20 psig. The LER Revision concluded that the potential concerns identified in the original LER 93-04 were eliminated.

Further review of the revised LER by the inspector indicated that the licensee attributed the cause for the potential design concerns to be inadequate documentation of existing plant conditions in the UFSAR. The inspector noted that, while the UFSAR was incorrect, the root cause was that the licensee had not fully known, evaluated, or documented the actual design basis. The LER Revision states that the UFSAR and other appropriate documentation will be revised to include the results of the recent calculation. The inspector had no further concerns. This item is closed.

6.0 EXIT INTERVIEWS/MEETINGS (40500,71707)

6.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the senior licensee management on February 4, 1994. 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; 28.5 of the direct inspection hours were performed during backshift periods, and 10 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.
January 7, 1994	Della Greca	EDSFI Followup	50-219/94-01
January 21, 1994	King	Security	50-219/94-02

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