U. S. NUCLEAR REGULATORY COMMISSION

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Licensee:	GPU Nuclear Corporation P.O. Box 480 Middletown, PA 17057
Facility:	Three Mile Island Station Units 1 and 2
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Inspection Summary

Core, regional initiative, and reactive inspections performed by the resident inspectors during Unit 1 plant activities are documented in the areas of plant operations, maintenance, engineering, and plant support. Additionally, inspections conducted by regional inspectors are documented in the areas of inservice inspection and radiological controls.

Results: An overview of the inspection results is in the executive summary.

EXECUTIVE SUMMARY
Three Mile Island Nuclear Power Station
Report No. 50-289/95-13

Plant Operations

Overall, activities associated with the 11R refuel outage were performed in a safe and controlled manner, with appropriate management oversight. A significant improvement, compared to the 10R outage was noted in the maintenance of proper water inventory when systems were removed from and returned to service. In addition, electrical bus outages were well controlled. Improved performance of the auxiliary operators was evident in that there were no safety tagging errors that impacted the operability of plant equipment. Operations personnel and the shift technical advisors jointly enforced the outage risk management guidelines to minimize plant risk. Significant emerging problems, such as the fuel degradation, excessive control rod drop times, and the main generator stator bar replacement, were appropriately elevated to management and resolved after assessing the impact of the problem and determining long term corrective actions to resolve the issues. The outage schedulers did an excellent job of factoring the emerging problems into the existing schedule to ensure management's attention remained focused on the most important work activities.

The control room operators' immediate response to the decay heat removal interruption and timely restoration was excellent. Their response reinforced the importance of training and the ability of the operators to respond to plant events that could impact safe plant operation. A second example of the resourceful use of training was evident in operation management's decision to train the crew scheduled to synchronize the main generator on the new digital turbine control system at the dynamic simulator the day before the evolution.

Weaknesses in communications between Instrumentation and Controls personnel and the control room supervisors contributed to an inadvertent heat sink protection system actuation which occurred during the period.

The decision making process involving a clogged strainer for decay river pump DR-P-1A was weak. Approximately ten hours after the high differential pressure (dp) was identified for the strainer, the licensee's plan was to continue to backwash the strainer for another shift or two, instead of taking steps to inspect the strainer to verify what was causing the high dp. Considering the potential generic concern with the other safety related river water pumps, it appears that a more timely approach was warranted to ensure the operability of the non-running pumps. In addition, the operating shifts operability call was weak, in that they did not consider the pump inoperable as a result of the high strainer dp, even though they had indication that the pump flow was less than the design basis flow. However, once plant engineering highlighted the significance of the issue, a Plant Review Group (PRG) meeting was held. The PRG decisions and recommendations were appropriately focused and they developed a good basis for concluding that the other non-running pumps were operable.

The building spray system components and systems, both electrical and mechanical, were in the required emergency standby alignment, instrumentation was valved in, and the overall conditions were satisfactory. Recent surveillance testing was satisfactorily performed within the required frequency.

The licensee's corrective actions to a November 1993 incident where an operations crew partially did not properly control a reactor coolant system drain down were determined to be thorough and should prevent recurrence of similar events. Changes to Operating Procedure 1103-11 "Draining and Nitrogen Blanketing of the Reactor Coolant System," significantly improved the operators' ability to control reactor vessel water level and decay heat removal pump suction during reactor coolant system drain down. During the two RCS mid loop drain down evolutions performed during the 11R refuel outage, the operations crews performed the drain downs in a controlled, cautious manner, without incident.

Maintenance

During the 11R refuel outage, in general maintenance and surveillance work activities were very well controlled and performed right the first time with little or no rework required. However, maintenance personnel did not use the "BE SURE" (Stop-Understand-Respond-Evaluate) self checking technique, prior to starting work on a motor operated valve, to verify that they were working on the correct component. As a result, the technicians replaced the torque limiter plate and spring pack on nuclear service valve NS-V-15 instead of NS-V-4 as specified on the work package.

The safety related work activities for decay heat removal valves DH-V-1&2 were very well coordinated and resulted in reduced plant risk based on selecting the best combination of plant conditions to perform the work activities and post maintenance test requirements.

Proper planning between the maintenance, quality verification, operations, and scheduling departments resulted in the completion of all fitting inspections and repair of the failed reactor coolant inventory trending system (RCITS) transmitter instrument line during the 11R refuel outage. RCITS was returned to an operable condition before the plant return to power operation.

Engineering

A weakness was noted in the plant engineering input to the planning process for the review and impact of the reactor pressure isolation logic to the DHR system. The weakness resulted in a momentary interruption of decay heat removal system flow.

The activities associated with the Reactor Building sump closeout inspection were very well conducted. The engineers involved with the inspection were aware of the recent industry problems related to debris in containment emergency sumps.

Plant engineering performed a detailed analysis which documented that the removal of one ball check valve from the control rod drive mechanism thermal barrier would not result in any additional plant safety concerns.

The licensee's fuel inspection activities were well controlled and fuel reconstitution work was performed satisfactorily using NRC approved methodologies.

The licensee's inservice inspection (ISI) plan was consistent with the requirements of ASME Section XI, and good performance was noted in implementing the ISI program, control of contractor activities, and during eddy current examinations of the steam generator tubes. However, for dispositioning some eddy current indications, the licensee is using a voltage-based criteria which has not been explicitly approved by NRR. This matter is presently under study, and is considered an unresolved item **(50-289/95-13-01)** until NRR can fully assess the use of this technique at TMI. A number of deficiencies were found in the Eddy Current Data Analysis Guidelines. The licensee indicated that they would review the guidelines for improvement prior to performing future examinations.

Corrective actions taken by plant engineering to enhance the Equipment Storage Log for Class 1 Buildings were found to be excellent and sufficient to reduce the probability of temporary equipment being stored unrestrained in seismic class I buildings.

Plant Support

The licensee had an overall effective program for occupational radiation protection during the refueling outage. One licensee-identified violation of procedures was noted regarding the release of contaminated equipment from the restricted area and the facility. This constituted a violation of minor consequence and is being treated as a non-cited violation, consistent with Section IV of the NRC Enforcement Policy. The licensee took appropriate and timely corrective actions for this incident, as well as most other recently-documented radiological incident reports and radiological awareness reports. However, another violation of licensee procedures was identified that involved an unauthorized entry into a radiography area. The immediate and long-term corrective actions for this violation were not considered sufficiently comprehensive to prevent recurrence of similar events. The licensee's problem identification and correction process was considered inadequate, in this instance, because: (1) the shift supervisor or other responsible licensee management was not provided an opportunity to exercise management oversight and review of the occurrence prior to the resumption of radiography operations, and (2) originally determined long-term corrective actions were limited only to review of use of postings for improvements. Consequently, the violation **(50-289/95-13-01)** is cited.

Training and qualifications for the temporary radiological controls outage staff were very good. Planning and preparation for outage work was also very good, including management support. External and internal exposure controls were effective. Control of radioactive material and contamination was good; however, personnel monitoring (frisking) and housekeeping in contaminated areas could be improved. Improvement was noted in tagging/labelling of radioactive materials. The radiological control support for the Reactor Building sump closeout inspection was thorough and contributed significantly to the satisfactory completion of the test. In particular, contamination controls were enforced from the pre-job preparations until the personnel exited the Reactor Building.

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

The PRG determined that the details of the momentary decay heat removal (DHR) system flow interruption should be documented in a voluntary LER even though the event did not result in a plant condition that matched the reportability criteria contained in 10 CFR 50.72 and 50.73. The decision highlighted plant management's understanding of the safety significance of DHR system flow interruptions.

The licensee's decision to replace 27 thermal barriers during the 11R refuel outage with the new design displayed a clear commitment to resolve the control rod drive mechanism drop time issue. In addition, their decision to replace all fuel rods that had cladding degradation was a strong example of their commitment to begin the operating cycle with no fuel defects.

The licensee adequately utilized self-assessments in identifying weaknesses in its inservice inspection program.

The licensee's efforts to work with the vendor to confirm the root cause of two heat sink protection system (HSPS) module failures that resulted in an inadvertent HSPS actuation, was a good initiative and should help to prevent additional inadvertent actuations. Their interim corrective action to perform logic testing after any complete loss of train power was considered appropriate.

Although the licensee had acknowledged that poor communications contributed to the inadvertent heat sink protection system actuation, initially they did not fully evaluate the causes for the communication weaknesses. Following discussion with the inspector, the licensee further investigated the communication weaknesses, however, due to the time lapse since the event occurred they were unable to clearly reproduce the communication exchange between the Instrumentation and Controls personnel and the control room supervisors. They did provide lessons learned to the operations and maintenance personnel regarding the communication weaknesses. However, a more thorough and methodical investigation closer to the time when the event occurred could have improved the licensee's understanding of the communication exchange and resulted in a better understanding of the event and implementation of more focused corrective actions.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

1.1 Licensee Activities

Unit 1 was shutdown on September 8, 1995, for the scheduled 11R refuel and maintenance outage. The outage work was completed in 34 days. The main generator was synchronized to the grid on October 13, 1995, and the plant reached 100% reactor power on October 16, 1995. The Unit remained at 100% power for the rest of the inspection period.

1.2 NRC Staff Activities

The inspectors assessed the adequacy of licensee activities for reactor safety, safeguards, and radiation protection, by reviewing information on a sampling basis. Information was obtained through actual observation of licensee activities, interviews with licensee personnel, and documentation reviews.

Licensee activities were observed during both normal and backshift hours; 108.5 hours of direct inspection were conducted on backshift. The times of backshift inspection were adjusted weekly to assure randomness.

2.0 PLANT OPERATIONS (71707, 60710, 92901, 40500)

2.1 Operational Safety Verification During the 11R Refuel Outage

The inspectors observed overall plant operation and verified that the licensee operated the plant safely and in accordance with procedures and regulatory requirements. Regular tours were conducted of the following plant areas:

- --Control Room
- --Switch Gear Areas
- --Access Control Points
- --Fuel Handling Building
- --Protected Area Fence Line
- --Reactor Building
- --Auxiliary Building
- --Turbine Building
- --Intake Structure
- --Intermediate Building
- --Diesel Generator Building

The inspectors' review included the planned shutdown prior to the scheduled 11R refuel and maintenance outage and subsequent plant startup. Emphasis was placed on observing the outage control meetings to determine the progression of work and prioritization of resources to address problems that impacted safety related equipment and activities. Plant conditions were observed through control room tours to verify proper alignment of engineered safety features and compliance with Technical Specifications. Facility records and logs were reviewed to determine if entries were accurate and identified equipment status or deficiencies. Detailed walkdowns of accessible areas were conducted to inspect major components and systems for leakage, proper alignment, and any general condition that might prevent fulfillment of their safety function.

The inspectors observed the plant shutdown leading into the 11R refuel and maintenance outage. The operators performed the shutdown without error. Because the shutdown was planned, operation's management scheduled additional control room and plant operators at key locations to focus more attention on infrequently operated equipment that was vital to the performance of a safe and controlled shutdown. Operators consistently used two way communications throughout the shutdown. Plant management provided continuous overview for the entire shutdown evolution. In addition to the normal shutdown, several detailed surveillance tests (STs) were performed with the plant still at power. The shift supervisor (SS) verified that the required plant conditions were established before each test. The inspectors noted that a thorough shift brief was performed by the SS prior to the STs for the simulated reactor coolant pump (RCP) trip, the main turbine functional test, and the control rod drop time testing.

The inspectors observed daily refuel outage control and a large sample of the safety related work activities. Management meetings were focused on the status of safety significant and outage critical path activities. Managers routinely emphasized to plant supervision and workers that they should, "take their time to do the job right the first time and not focus on the schedule time lines." The Operations department maintained strict control of the refuel outage evolutions. Significant improvements, compared to the 10R refuel outage, were noted in the maintenance of proper water inventory when systems were removed and returned to service and in the control of electrical bus outages. There were no examples of uncontrolled water transfers during the 11R refuel outage. Also, improved performance of the auxiliary operators (AOs) was evident in that there were no safety tagging errors that impacted the operability of plant equipment. Shift Supervisors, shift foremen (SF), and operations engineering staff provided direct supervision in the plant throughout the refuel outage. In particular, the inspectors observed direct operation supervision in the Reactor Building (RB) during all safety significant work related to the reactor coolant system pressure boundary and fuel transfer evolutions. The shift technical advisors (STAs) and operation personnel jointly enforced the outage risk management guidelines to minimize plant risk. When significant problems emerged such as fuel clad corrosion, additional thermal barrier replacement, and main generator stator bar replacement; they were elevated to the proper level of management and resolved after assessing the impact of the problem and determining long term corrective actions to resolve the issues. The outage schedulers did an excellent job of factoring the emerging problems into the existing schedule to ensure management's attention remained focused on the most important work activities.

After completion of the outage work, the plant transitioned into a reactor coolant system (RCS) heatup to 525°F and reactor startup. An area for improvement was noted in the control of systems needed to support the plant heatup and reactor startup. It was not always clear that system status was documented completely as the startup progressed from heatup to reactor criticality. In part, the controlling procedure OP 1102-1, "Plant Heatup to 525°F," did not always differentiate between system conditions required for heatup versus conditions required for reactor criticality. Even though no significant problems were noted for this startup, the potential exists that the proper system alignments may not be correct for future plant startups. Licensee management acknowledged the inspectors' concerns and stated that the OP would be evaluated for improvements.

An example of the resourceful use of training was evident in operation management's decision to train the crew scheduled to synchronize the main generator on the new digital turbine control system (DTCS) at the dynamic simulator. During turbine control valve testing on October 15, 1995, a minor transient occurred with the plant at 82% reactor power. Following testing of the first control valve, a DTCS software problem resulted in load demand being 20%, with actual reactor power at 82%. A runback on load toward 20% power occurred. The operators handled the transient in an excellent manner, quickly taking manual control of the load demand and stopping the power runback at 67%. No additional control valve testing was performed. The licensee investigated the software problem and determined that this portion of the DTCS logic had not been designed properly. Configuration change request (CCR) #95-069 was written to modify the logic.

The inspectors concluded that the licensee conducted overall plant operations in a safe and conservative manner.

2.2 Momentary Interruption of Decay Heat Removal Flow (Closed, Voluntary LER 95-004)

On September 12, 1995, there was a momentary interruption of decay heat removal (DHR) flow to the reactor core due to an inadvertent closure of the pump suction isolation valve DH-V-1. The DHR pump suction motor operated valve (MOV), one of three MOVs in the flow path, received a close signal during replacement of a relay coil in the engineered safeguards actuation system (ESAS). The relay coil was being replaced as part of a planned ten year preventive maintenance (PM) task. The relay provides an electrical interlock to close DH-V-1, not a primary containment isolation valve, to prevent overpressurization of the DHR pipe system. At the time of the interruption, the reactor coolant system was de-pressurized and cooled down to approximately 131°F.

The inspectors observed the operations response to the event in the main control room. The control room operators (CROs) immediate response and timely restoration was excellent. The CROs detected the abnormal condition and restored the DHR system flow, within 45 seconds, to minimize reactor coolant system (RCS) heatup. The RCS temperature increased from 131°F to 138°F due to the DHR flow interruption. The RCS temperature remained well below the Technical Specification limit for the plant cold shutdown condition. The CROs satisfactorily implemented the immediate actions in Operating Procedure OP-1235, "Loss Of Decay Heat Removal." The operator requalification training, completed prior to the refuel outage, covered loss of DHR events in the classroom and on the dynamic plant simulator. The operators' response to the event reinforced the importance of training and the ability of the operators to respond to plant events that could impact safe plant operation.

To prevent additional flow interruptions, the plant operators opened the electrical supply breakers for DH-V-1 and DH-V-2 with the valves in the full open position. The electrical breakers for DH-V-1 and DH-V-2 were controlled by the RCS draindown procedure to allow opening the breakers when RCS pressure was below 400 psig and the RCS was properly vented. At the time of the inadvertent valve closure, the operators were one procedure step away from opening the breakers for DH-V-1 and DH-V-2. The Plant Review Group (PRG) noted that the RCS draindown procedure could be revised to provide more flexibility for opening the DHR valve breakers earlier in the draindown while maintaining the safety requirements.

A weakness was noted in the plant engineering input to the planning process for the review and potential impact of the scheduled ten year PM for the reactor pressure isolation logic to the DHR system. The high RCS pressure interlock relays to close DH-V-1&2 are located in the ESAS relay cabinet but are not part of the ESAS logic circuit. The personnel involved made an incorrect assumption that the DH-V-1&2 interlock actuation required two out three inputs to close the valves. Therefore, in an attempt to prevent any inadvertent system actuation, the electrical relays were scheduled to be replaced one channel at a time. However, the interlock only requires a one out of one signal to close the valves. Event or Near Miss Capture Form No. 95-246 was submitted to review the event and determine the root cause(s). The licensee review of the event determined that the maintenance procedure used to perform the relay replacement did not contain sufficient precautions to alert the technicians of the DH-V-1&2 high pressure interlock logic. The maintenance procedure used to perform the work 1420-Y-11, "ESAS Channel Relay Maintenance," is scheduled to be revised to include the necessary cautions related to the relay work impact on DH-V-1&2.

The inspectors observed the PRG meeting to discuss the potential reportability of the DHR interruption. The PRG determined that the details of the momentary DHR flow interruption should be documented even though the event did not result in a plant condition that matched the reportability criteria contained in 10 CFR 50.72 and 50.73. The PRG personnel decided to submit a voluntary Licensee Event Report (LER) due to the safety significance of the DHR system.

The CROs immediate response to the DHR interruption and timely restoration was excellent. A weakness was noted in the plant engineering input to the planning process for the review and impact of the reactor pressure isolation logic to the DHR system. The PRG decision to document the DHR event in a voluntary LER highlighted plant management's understanding of the safety significance of DHR system flow interruptions. The event investigation and root cause analysis were detailed and the completed and planned corrective actions were thorough and should address the cause of the event. LER 95-004 is closed.

2.3 Inadvertent Heat Sink Protection System Actuation (Closed, LER 95-005)

On October 12, 1995, at 3:05 p.m., during the startup sequence following the 11R refueling outage, an inadvertent actuation of the heat sink protection system (HSPS) for the 'B' once-through steam generator (OTSG) occurred. The unit was operating at low power (10E-8 amps) and the licensee reported the actuation to the NRC via the Emergency Notification System (ENS) in accordance with 50.72 (b)(2)(ii). Although the HSPS is not considered an engineered safety feature, the licensee had previously committed to Region I personnel to report actuation of HSPS in order to be consistent with other plants.

The HSPS provides the necessary instrumentation and controls to isolate main feedwater (MFW) when required. Steam pressure and water level are monitored for each OTSG. On high OTSG level, MFW is isolated to prevent overfilling the OTSG and on low OTSG pressure, MFW is isolated to prevent feeding a faulted OTSG in order to maintain appropriate reactor coolant system (RCS) cooling and minimize energy released to the reactor building atmosphere. There are two HSPS trains, 'A' and 'B'. Each HSPS train is arranged in a two out of four twice, energize to actuate logic scheme, so that no single failure can prevent or cause an actuation. For example, if 2 out of 4 level switches sense high level and the actuation train is enabled, MFW to the affected OTSG will be isolated. This is done by energizing the closing circuit for the main FW block valve (FW-V-5A/B) and the startup FW block valve (FW-V-92A/B) and by isolating and venting the motive air to the main FW control valve (FW-V-17A/B) and the startup FW control valve (FW-V-16A/B). High level or low pressure will isolate MFW only to the OTSG with the sensed problem. For OTSG 'A', actuation of HSPS train 'A' will close valves FW-V-5A and 92A and actuation of HSPS train 'B' will close valves FW-V-16A and 17A. For OTSG 'B', actuation of HSPS train 'A' will close valves FW-V-16B and 17B and actuation of HSPS train 'B' will close valves FW-V-5B and 92B.

At about 9:00 a.m. on October 12, Instrumentation and Controls (I&C) supervision was informed that the 'B' OTSG low pressure annunciator (alarm J-2-6) had alarmed in the control room. Following some troubleshooting activities, I&C determined that a problem existed with the HSPS train 'A' - OTSG 'B' MFW isolation logic on low OTSG pressure. An HSPS 'A' train logic module which is interlocked with the main and startup FW control valves FW-V-17B and FW-V-16B as well as the control room annunciator were believed to have failed. A decision was made that the module would need to be replaced. Prior to replacing the module, I&C inspected the status lights on both the HSPS train 'A' and 'B' cabinets. Status lights are normally either on or off, where the on state indicates that some portion of the HSPS actuation logic has been satisfied. The two train 'A' lights associated with the module being replaced were still faintly lit. However, eight train 'B' lights were also observed to be faintly lit. The dim lamps were indicative of a potential problem in the HSPS train 'B' actuation logic, since the lamps are not designed to have a dim state.

All of the eight HSPS train 'B' lights were associated with OTSG 'B' hi-hi level MFW isolation logic. If the dim lamps were valid indications, OTSG 'B' main and startup FW block valves FW-V-5B and FW-V-92B would have been receiving a close signal. Actuation relay status lamps were immediately checked and showed that an isolation signal was not applied to the valves' closing circuit. The presence of dim lamps in HSPS train 'B' and their association with the hi-hi level MFW isolation logic was reported to the control room personnel. The HSPS MFW isolation feature on hi-hi OTSG level is not required by plant Technical Specifications (TS). Therefore, the HSPS train 'B'- OTSG 'B' MFW isolation on hi-hi level defeat/enable switch could have been placed in defeat once the dim lamps were recognized. However, poor communications between I&C personnel and the control room staff led to the misunderstanding that the additional dim lamps were associated with the HSPS train 'A' lo-lo OTSG pressure logic which by plant TS cannot be defeated above 750 psig. I&C personnel did not believe that an HSPS actuation was imminent and decided to complete the HSPS train 'A' repair work prior to seeking approval to troubleshoot the dim lamps in train 'B'.

The defective train 'A' module was removed. Configuration of the removed and replacement module was being compared prior to installation of the new module when control room alarm "OTSG 'B' MFW isolated" (J-1-8) actuated and the OTSG 'B' startup FW block valve (FW-V-92B) closed. Main FW block valve FW-V-5B was normally closed at this point in the startup and did not change position. There was no valid actuation signal; OTSG 'B' pressure and level were normal. As a result of the poor communication which had occurred earlier with I&C personnel, operations attempted to defeat the actuation by first pressing the HSPS train 'B' lo-lo pressure defeat pushbutton switch. FW-V-92B could not be re-opened. The HSPS train 'B' hi-hi level defeat/enable switch was then placed in defeat, allowing FW-V-92B to be re-opened. OTSG 'B' level had dropped from approximately 25 to 17 inches. Normal OTSG level of 25 inches was restored and no emergency feedwater actuation on lo-lo OTSG level (10 inch setpoint) occurred.

The breaker for FW-V-92B was opened to prevent a second actuation while the cause for the event was being evaluated. With the breaker open and the HSPS train 'A' module not yet returned to service, both trains of the OTSG 'B' MFW isolation on low pressure were inoperable per TS 3.5.1.9.1, requiring that one train be restored to operable condition within one hour or be in Hot Shutdown within the next 6 hours. FW-V-92B's breaker was closed 1.5 hours later restoring HSPS train 'B' to an operable status. Since the reactor was at low power, the licensee did not take any immediate action to place the plant in Hot Shutdown. Maintenance on the train 'A' module was completed and successfully tested restoring the HSPS train 'A' - OTSG 'B' MFW isolation logic on low OTSG pressure to an operable status. Troubleshooting and repair of the train 'B' module commenced shortly thereafter.

The inspector reviewed the details of the HSPS actuation, interviewed personnel involved in the event, and discussed the event with licensee management personnel. The inspector also attended a Plant Review Group (PRG) meeting at which the root cause and corrective actions for the event where discussed. Licensee preliminary investigation indicated that the failure of the two modules was due to blown board level fuses. The licensee believes that power switching transients, due to de-energizing and re-energizing the train cabinets during the refueling outage, caused the fuses to blow. The licensee has contacted the equipment manufacturer to confirm the presumed failure mode. The licensee determined that until a hardware resolution could be implemented, testing of the HSPS train logic would be required after any complete loss of train power or after removing or losing power to similar type modules. The inspector found that this interim corrective action was acceptable. The licensee submitted Licensee Event Report (LER) 95-005 on November 9, 1995, in which they stated that they intended to complete their work with the vendor to confirm the root cause of the module failure by mid June 1996. They plan to submit a supplemental LER at that time.

At the PRG meeting and through discussions with personnel involved in the event, the inspector was concerned that although the licensee had acknowledged that poor communications contributed to this event, they had not fully evaluated the causes for the communication weaknesses. Because of this, it was not clear to the inspector if the licensee's planned corrective actions were appropriate to prevent recurrence. The inspector discussed this concern with licensee management who initiated actions to more fully investigate the reasons for the communication weaknesses and revise their planned corrective actions if necessary. However, due to the time lapse since the event occurred, they were unable to clearly reproduce the communication exchange between the Instrumentation and Controls personnel and the control room supervisors. They did provide lessons learned to the operations and maintenance personnel regarding the communications weaknesses in a memorandum from the Operations Director, dated November 15, 1995. However, a more thorough and methodical investigation closer to the time when the event occurred could have improved the licensee's understanding of the event and implementation of more focused corrective actions. LER 95-005 is closed.

2.4 Decay River Pump Suction Strainer High Differential Pressure

On October 23, 1995, the control room operators (CROs) started decay river (DR) pump, DR-P-1A, to increase dilution flow for an industrial waste treatment system (IWTS) release. The DR pump strainer accumulated debris in a short period of time and at 8:51 p.m. the high strainer differential pressure (dp) alarm was received in the control room. When investigated, the local dp was found to be about 19.5 psid. Although shift supervision had indication that the pump flow was about 7000 gpm at this time (minimum design basis flow per surveillance procedure 1300-3D, "IST of DR pumps and Valves," is 8000 gpm), the shift supervisor (SS) did not declare the pump inoperable. Instead, the pump was shutdown and attempts were made to reduce the dp on the strainer through increased backwashing. At 3:57 a.m. on October 24, 1995, the breaker for the pump discharge valve, DR-V-1A, was opened to allow manual local operation of the valve. The valve was partially closed to support additional cleaning of the pump strainer. A 72 hour Technical Specification (TS) time clock was entered at that time for the 'A' DR train since the discharge valve was in a throttled position.

On October 24, the inspector attended the 6:30 a.m. morning managers' meeting and discussed the condition of the DR pump strainer with the CROs and the SS. Licensee management indicated that some algae had been identified at the screenhouse, and that was what they believed had caused the high strainer dp. The CROs stressed at turnover not to run the other DR pump, DR-P-1B, considering the condition of the 'A' pump. The SS stated that the current plan was to continue to run DR-P-1A with the discharge valve in the throttled position for a shift or two to attempt to clean the strainer and reduce the dp. At that time, the inspector began to question licensee management and staff regarding the operability of the 'B' DR pump considering that there was a potential for a common problem with algae in the intake structure. At that time, it was not apparent to the inspector that the licensee had fully considered and evaluated operability of the other pumps in the screenhouse including DR-P-1B.

At about 10:00 a.m. on October 24, 1995, the inspector attended a Plant Review Group (PRG) meeting at which the condition of DR-P-1A was discussed. The PRG determined that the pump should have been declared inoperable at 8:51 p.m. on October 23, when the strainer high dp was identified. The PRG also recommended that expeditious action by maintenance personnel should be taken to inspect and clean the DR-P-1A strainer and determine the cause of the high dp. In addition, they recommended that environmental controls personnel should take samples in the screenhouse to determine the extent of the algae problem.

The PRG also discussed whether the condition which caused DR-P-1A to become inoperable could also affect the other non-running pumps, specifically DR-P-1B and the reactor river water (RR) pumps RR-P-1A and 1B. Based on the information available at the time, the PRG believed that algae had entered the screenhouse as a result of heavy rains on October 21 and 22, 1995. This condition did not appear to affect the operating pump strainers. The running service water and nuclear river water pumps had higher than normal strainer dps but they were still satisfactory. It appeared likely that the running pumps were able to handle the algae as it entered the screenhouse, but algae may have accumulated near the idle pumps, such as DR-P-1A. The DR pumps are low head pumps, which decreases the effectiveness of the strainer backwash. Based on algae accumulation in the travelling screens, the licensee believed that most algae had accumulated in the south end of the screenhouse, which is where DR-P-1A is located. Therefore, the PRG believed that since DR-P-1B was in the north section of the screenhouse, it was less likely that algae had accumulated at the pump suction. The RR pumps are higher head pumps than the DR pumps, so their strainer backwash is more effective. RR-P-1B is in the south section of the screenhouse, while RR-P-1A is in the north section. Based on these considerations, the PRG believed that DR-P-1B, RR-P-1A, and RR-P-1B were currently operable. The results of the strainer inspection and the samples in the screenhouse would be used to support or negate their conclusion.

Around noon, on October 24, the DR-P-1A pump strainer was inspected by maintenance and it was determined that the strainer was clogged with algae, fish parts, leaves, and sticks. Environmental Controls sampled the screenhouse for algae. Essentially no algae was found inside the screenhouse, and only minor floating sticks and leaves. The strainer was manually unclogged and the pump was run for about an hour on October 25 and returned to service at about 1:30 a.m. DR-P-1B and RR-P-1B were then run with no evidence of strainer fouling. These runs confirmed the PRGs initial operability determination.

The inspector interviewed several operations and engineering personnel involved in the licensee's decision making process for the DR strainer high dp issue. The inspector found that the decision making process was weak, because at 7:00 a.m. on October 24, (approximately 10 hours after the initial condition was identified) the licensee's plan was to continue to backwash the DR-P-1A strainer for another shift or two, instead of taking steps to inspect the strainer to verify what was causing the high dp. Considering the potential generic concern with the other safety related river water pumps, it appears that a more timely approach was warranted to ensure the operability of the non-running pumps. The inspector did note that once the day shift came in and plant engineering highlighted the significance of the issue, a PRG meeting was held. The inspector found the PRG decisions and recommendations to be appropriately focused and they developed a good basis for concluding that the other non-running pumps were operable.

In addition, the inspector found that the operating shifts operability call was weak, in that they did not consider the pump inoperable as a result of the high strainer dp, even though they believed that the pump flow was less than the design basis flow. Instead, they did not consider the pump inoperable until the discharge valve breaker was opened.

The inspector discussed these concerns with licensee management. The licensee expanded the scope of Event Capture Form #95-295 which had been written for this event to include review of the human performance issues related with the decision making process involving the high strainer dp. Licensee management currently has not provided written guidance for operability decisions to the operations staff. The Operations Engineer indicated improvements in this area would be considered as part of the evaluation of the event capture form.

2.5 Engineered Safety Feature System Walkdown - Reactor Building Spray

The inspector verified the operability of the reactor building spray (BS) system for its emergency standby mode by performing a detailed walkdown of accessible portions of the system during the period October 10 through October 18, 1995. The inspector reviewed Operating Procedure (OP) 1104-5, "Reactor Building Spray System," and Drawing Number 302-712, "Reactor Building Spray Flow Diagram." The inspector reviewed OP 1104-5, Enclosure I, "Startup Valve Checklist," which had been completed on October 10, 1995, and independently verified valve positions for a sampling of valves located in the reactor building, the auxiliary building, and in the BS vaults for both BS trains. The inspector also reviewed the results for several of the most recent performances of Technical Specification surveillance procedures related to the BS system. These included 1303-4.14, "Reactor Building 30 PSIG Analog Channels," 1300-3A, "IST of BS-P1A/B and Valves," and 1302-5.10, "Reactor Building 4 PSIG Channel."

The inspector confirmed that the BS components and systems, both electrical and mechanical, were in the required emergency standby alignment, instrumentation was valved in, and that the overall conditions were satisfactory. For the surveillance testing reviewed, the results were satisfactory and testing had been performed within the required frequency. The as-built prints reflected the as-installed systems with the exception of vent valve BS-V12A located on the top of the sodium thiosulfate tank. This tank had previously been removed from service and BS-V-12A was opened and the downstream blank flange was removed. OP 1104-5 accurately reflected this condition, however, Drawing No. 302-712 did not. The licensee initiated Field Change Notice (FCN) 083493 to update the drawing. In addition, the inspector noted that boron had degraded the concrete near the sodium hydroxide tank drain valves BS-V50A and BS-V56A. The inspector discussed this issue with licensee personnel and maintenance management. The leakage related to BS-V56A was previously identified and work had been performed during the outage to address the issue. However, leakage related to BS-V50A had not been previously addressed so the licensee initiated a configuration change request to correct the leakage.

2.6 (Closed) Violation (VIO, 50-289/94-02-01) Reactor Coolant System Drain Down

This item concerned a November 15 and 16, 1993, incident where an operations crew did not properly control some activities related to a reactor coolant system (RCS) drain down per Operating Procedure (OP) 1103-11, "Draining and Nitrogen Blanketing of the Reactor Coolant System." For this inspection, the inspectors reviewed the November 1993 drain down evolution, described in NRC Inspection Report No. 50-289/94-02, and licensee Plant Experience Report No. 94-003. To summarize the inspectors' original concerns, the licensee failed to establish an adequate procedure for draining the reactor coolant system because OP 1103-11 did not address how to minimize or prevent the reactor vessel level effects from the spill over of reactor vessel water into the cold legs as the cold legs are drained. As a result, on November 16, 1993, the indicated reactor vessel level on level transmitter LT-1037, twice dropped below the curve of OP 1103-11, Figure 10, "Minimum Height of Water Required to Avoid Vortex Formation vs. Decay Heat Flow." During this drain down the RCS was vented through a primary hand hole on each hot leg, one control rod drive vent, and a vent on each of the four reactor coolant pump (RCP) seal assemblies.

The inspectors reviewed Operating Procedure 1103-11, "Draining and Nitrogen Blanketing of the Reactor Coolant System," to determine if the procedure was revised to provide clear direction to the operators for proper RCS draindown to the cold leg pipe midloop. The procedure was revised to include: 1) clear direction to open a sufficient number of RCS vent paths to prevent drawing a vacuum on the RCS during the water draindown; 2) improved requirements for throttling the decay heat removal (DHR) system flow to provide more margin to pump vortex limits; 3) a new procedure Caution that provides the expected RCS water level when the RCP spill over region is reached; and 4) venting the draindown water level instrument reference leg to the reactor vessel to ensure the indicated water level is conservative. In addition to the procedure changes, "margin to DHR pump vortex" alarms were installed on the control room computer to alert operators if RCS level was too low for the corresponding DHR pump flow.

The inspectors observed both RCS mid loop draindown evolutions that were performed during the 11R refueling outage. Prior to both evolutions a detailed pre-evolution briefing was provided to the shift personnel by the shift supervisor (SS). The Director of Operations emphasized the need to "self check" and reviewed some of the problems from previous RCS draindown evolutions. The SS directed a controlled methodical draindown of the RCS water level. To ensure the RCS was properly vented, the operators paused several times before the RCP spillover level was reached. Also, four additional RCS vents were opened by procedure to prevent formation of a vacuum in the RCS during draindown. The minimum water level, in the revised procedure, was not reached prior to breaking the RCP loop seal.

The control room operators were very knowledgeable of the DHR pump vortex limits and understood the control room indications that would indicate a pump suction problem. The procedure curve OP 1103-11, Figure 10, provided a clear minimum water level necessary to avoid vortex formation versus DHR pump flow. The curve included the draindown water level instrument error to provide a conservative margin of safety to the vortex limit. The shift technical advisor (STA) monitored the DHR system flow and margin to pump vortex limits on the plant computer. The inspectors verified that the DHR pump vortex limits were not exceeded during the time the RCS was drained down to the mid loop water level.

The procedure changes significantly improved the operators' ability to control reactor vessel water level and decay heat removal pump suction during reactor coolant system drain down. The inspectors concluded that OP 1103-11 was revised satisfactorily to address prior problems related to the spill over of reactor vessel water into the cold legs. As part of the respo to the violation, the licensee completed the installation of a marg vortexing computer alarm, clarified the proper valve alignment to ensure there was proper venting of the reference leg for LT-1037 to minimize the vessel level indication error, and accounted for the instrument error in the DHR vortex graph. The inspectors determined that the licensee's corrective actions were adequate to prevent recurrence of similar events. This item is closed.

3.0 MAINTENANCE (61726, 62703, 71707, 92902)

3.1 Maintenance Observations

The inspector reviewed selected maintenance activities to assure that: the activity did not violate Technical Specification Limiting Conditions for Operation and that redundant components were operable; required approvals and releases had been obtained prior to commencing work; procedures used for the task were adequate and work was within the skills of the craft; maintenance technicians were properly qualified; radiological and fire prevention controls were adequate; and equipment was properly tested and returned to service.

Maintenance activities reviewed included:

- Job Order No. 98486, "Fuel Bundle Clad Inspection and Fuel Pin Reconstitution."
- Job Order Nos. 79000 and 79232, "Decay Heat Valves DH-V-1&2 MOV Maintenance and Testing."
- Job Order No. 105569, "RCITS Parker-Hannifin inspections in the Reactor Building."

The inspectors observed the performance of work activities documented in Job Order 105569, "Inspection of Parker/Hannifin Fittings," to review a sample of reactor coolant inventory trending system (RCITS) instrument fitting inspections. The inspections were planned after a reactor coolant system (RCS) leak occurred on March 7, 1995. Background and details of the RCS leak and associated corrective actions were discussed in NRC Inspection Report

50-289/95-03, dated May 4, 1995, and the Licensee Event Report (LER) 95-001-00 dated April 6, 1995. In the LER the licensee stated that all RCITS fittings would be inspected during the 11R outage and that all repairs would be completed prior to the cycle 11 startup.

Because of the high radiation levels in the Reactor Building (RB), with the plant operating at full power and the risk associated with performing the maintenance on a high pressure system, the RCITS fitting inspections in the RB were performed during the 11R refuel outage. The inspectors observed good maintenance work practices, continuous quality verification (QV) oversight, and proper maintenance supervision. In addition to work oversight, the QV inspectors supported the inspection data acquisition to document the Parker/Hannifin fitting instrument line conditions. Overall, the inspections did not find any additional fittings without proper ferrule compression. However, the maintenance personnel did correct a few instrument line end connections that were apparently cut by a hack saw instead of the recommended tube cutter. A system hydrostatic test was performed satisfactorily to ensure all RCITS instrument lines and fittings could withstand design system pressure. Proper planning between the maintenance, QV, operations, and scheduling departments resulted in the completion of all fitting inspections and repair of the failed RCITS transmitter instrument line during the 11R refuel outage. RCITS was returned to an operable condition before the plant was returned to power operation.

With the exception of the work on the wrong motor operated valve, discussed in Section 3.3, the maintenance work activities were very well controlled and performed right the first time with little or no rework required. Job Orders 79000 and 79232 are discussed in detail in Section 3.4.

3.2 Surveillance Observations

The inspectors observed the conduct of surveillance tests to verify that approved procedures were being used, test instrumentation was calibrated, qualified personnel were performing the tests, and test acceptance criteria were met. They verified that the surveillance tests had been properly scheduled and approved by shift supervision prior to performance, control room operators were knowledgeable about testing in progress, and redundant systems or components were available for service as required. The inspectors routinely verified adequate performance of daily surveillance tests including instrument channel checks and reactor coolant system leakage measurement.

Surveillance activities reviewed included:

- Surveillance Procedure 1301-1, "Decay Heat Removal Operability Verifications."
- Surveillance Procedure 1303-11.1, "Control Rod Drop Time Test."
- Surveillance Procedure 1303-11.19, "Turbine Overspeed Testing."
- Surveillance Procedure 1303-11.16, "Decay Heat Leak Test."

The inspectors observed the Reactor Building (RB) sump closeout inspection. Surveillance procedure 1303-11.16, "Decay Heat Leak Test," provided the sump inspection requirements. Prior to the inspection, the RB sump was pumped dry and cleaned to remove any debris that could impact the operability of the safety related low pressure injection (LPI) and building spray (BS) systems. The inspection was completed satisfactorily and the sump filter screen area was sealed closed to prevent intrusion of foreign material. The engineers involved with the inspection were aware of the recent industry problems related to debris in containment emergency sumps. Radiological Controls support for the inspection was thorough and contributed significantly to the satisfactory performance of the test. In particular, contamination controls were enforced from the pre-job dressout until the personnel exited the RB.

The inspectors found that the overall conduct of the surveillance activities was good. The control rod drop time surveillance test is discussed in Section 4.1.

3.3 Motor Operated Valve Preventive Maintenance Performed on the Wrong Safety Related Valve

The inspectors reviewed the activities that resulted in the maintenance work on the wrong motor operated valve (MOV). The maintenance error occurred on September 14, 1995, during the 11R refuel outage. The job order (JO) stated clearly that the work task was scheduled for nuclear service (NS) closed cooling water valve NS-V-4. The maintenance technicians assumed incorrectly that a similar type of MOV, NS-V-15, was the right valve scheduled for work. The inspectors' assessment of the activity was based on a review of the associated maintenance documentation and the event evaluation completed by the human performance evaluation engineer. The inspectors concluded that the lack of self checking was a primary factor that contributed to the electrical maintenance personnel installing a torque limiter plate and spring pack on the wrong valve. The incorrect execution of the JO requirement was a violation of Technical Specification 6.8.1. Because the error was discovered by the licensee and corrected before stroking NS-V-15, the safety significance was minimized. Therefore, this failure is being treated as a non-cited violation, consistent with section IV of the enforcement policy.

A category one Event or Near Miss Capture Form, No. 95-247, was submitted to perform a detailed evaluation of the event and determine the root cause(s). The human performance evaluation engineer performed a detailed evaluation of the activities related to the work on the wrong MOV. Maintenance personnel did not use the "BE SURE" (Stop-Understand-Respond-Evaluate) self checking technique, prior to starting work, to verify that they were working on the correct component. The maintenance technicians assumed incorrectly that a similar type of MOV was the valve scheduled for work. In response to recent similar self checking weaknesses, the licensee is in the process of formulating specific self checking expectation for workers in each department. The individualized worker expectations should be an improvement to emphasize personnel accountability when compared to the existing generic self checking guidelines.

In summary, maintenance personnel did not use the "BE SURE" (Stop-Understand-Respond-Evaluate) self checking technique, prior to starting work, to verify that they were working on the correct component. The licensee performed a detailed root cause analysis and evaluation of the work activities. The licensee's decision to address the individualized worker expectations should be a positive step toward minimizing personnel errors when compared to the existing generic self checking guidelines.

3.4 Decay Heat System Motor Operated Valve Maintenance and Testing Activities

The inspectors reviewed the preparations for and control of work for two decay heat removal (DHR) system suction line motor operated valves (MOVs), DH-V-1&2. Both valves are located in the Reactor Building and are connected to the RCS hot leg pipe. DH-V-1&2 MOV work activities were coordinated to reduce plant risk based on selecting the best combination of plant conditions to perform the work activities and post maintenance test requirements.

A detailed review prior to the outage resulted in the implementation of alternate methods to ensure DH-V-1&2 remained open during DHR operation. If needed to isolate a system water leak, the outboard containment isolation valve, DH-V-3, remained operable during the work on DH-V-1&2. Maintenance was controlled so that only one valve was worked at a time. Control room operators were provided the details of the work activities and understood their responsibilities if a problem occurred during the valve maintenance.

The inspectors concluded that the DH-V-1&2 MOV work activities were very well coordinated to reduce plant risk based on selecting the best combination of plant conditions to perform the work activities and post maintenance test requirements. Plant personnel were sensitive to the safety significance related to working on the DHR suction line and understood their individual responsibilities if a problem occurred during the valve maintenance.

4.0 **ENGINEERING** (37551, 40500, 71707, 73753, 92903)

4.1 Excessive Control Rod Drop Times (Closed, LER 95-002)

On September 8, 1995, during the shutdown for the 11R refueling outage, the licensee performed control rod drop testing per Surveillance Procedure 1303-11.1, "Control Rod Drop Time." The licensee had committed to perform this testing as described in the Control Rod Drive Long Range Plan, GPUN Letter to the NRC (C311-94-2125), dated September 29, 1994. Beginning in October 1993, the licensee had experienced trip insertion times for the control rod drive mechanisms (CRDMs) which exceeded the Technical Specification (TS) 4.7.1.1 limit of 1.66 seconds. The licensee identified that the cause for the increased times was accumulation of corrosion deposits in the CRDM thermal barrier ball check valves and the lead screw guide bushing. The corrosion deposits tend to block the four check valves in the thermal barrier and reduce the clearance in the lead screw guide bushing. The blocked check valves and reduced clearance hydraulically slow the descent of the control rod and lead screw. During a mid-cycle outage in June 1994, the licensee replaced the thermal barriers for four CRDMs with new barriers with larger clearances in the region of the ball check valves.

Of the 61 CRDMs tested on September 8, 1995, seven exceeded the TS limit of 1.66 seconds. Four CRDMs (rods 1-1, 3-5, 3-3, and 5-7) had previously exceeded the TS criteria in March 1994. The other three rods (4-3, 7-9, and 5-11) had not previously exceeded the criteria, although they had experienced degraded drop times. Several other CRDMs exceeded the licensee's threshold (greater than 1.45 seconds) for thermal barrier replacement. This lower limit was based on previous drop time data which concluded that during a two year operating cycle any CRDM with a drop time greater than 1.45 seconds could exceed the TS limit before the next scheduled outage. Based on these test results, the licensee decided to replace the thermal barriers for 24 CRDMs during the 11R outage. The thermal barriers were also replaced for three additional CRDMs when they were removed to replace flange gaskets due to indication of flange leakage.

The 27 replacement thermal barriers installed during the 11R outage were different from the replacement barriers installed in June 1994. In addition to larger clearances, they were manufactured with one of the four ball check valves removed from the thermal barrier. The four ball check valves are designed to reposition on a reactor trip signal to allow reactor coolant system (RCS) water to flow into the upper part of the CRDM. The RCS water replaces the void left by the CRDM lead screw when the rod drops into the reactor core on a reactor trip. Test data has demonstrated that if one of the four ball check valves reposition, the control rod drop time will be within the allowable TS limit. Engineering performed a safety evaluation, No. SE-123331-001, that documented the tests performed to verify that the removal of one ball check valve would not result in any additional CRDM safety concerns.

On October 11, 1995, in conjunction with the plant startup after completion of the 11R outage, the licensee performed additional control rod drop testing to evaluate the condition of the CRDMs. The drop times were all below the TS criteria of 1.66 seconds. The licensee submitted Licensee Event Report 95-002 on October 3, 1995 to document the September 8, 1995 test results and the corrective actions they had or planned to take. At the completion of the 11R outage, 31 tripable CRDMs had new thermal barriers installed. Of the 30 remaining CRDMs, eight CRDMs are Group 7 rods, which have not shown deterioration based on trip insertion time performance and 10R CRDM disassembly and inspection and 11R lead screw inspections. The licensee intends to replace the thermal barriers for the remaining 22 CRDMs by the 13R refueling outage, consistent with their Long Range Plan commitments.

The inspectors observed the drop time testing performed on September 8, 1995, and activities involving replacement of the thermal barriers during the 11R outage. The inspectors found that the licensee's decision to replace 27 thermal barriers with the new design displayed a clear commitment to resolve the CRDM drop time issue. In addition, the inspectors reviewed the safety evaluation to support the removal of one ball check valve from the thermal barrier and found that plant engineering had performed a detailed analysis which documented that the change would not result in any additional CRDM safety concerns. LER 95-002 is closed.

4.2 Fuel Inspections and Fuel Assembly Degradation

Based on radiochemistry results obtained during Operating Cycle 10, which predicted 6-8 fuel rod failures, the licensee decided to perform a full core offload and ultrasonic testing (UT) of each fuel assembly during the 11R refueling outage. The licensee identified nine defective fuel rods (through-wall pinhole leaks) through a combination of UT and eddy current testing (ECT). The defective rods were in the most recently loaded batch ("first-burn" rods), which were installed in October 1993 (24-month core).

During the examination of the fuel pins, the licensee and B&W observed a distinctive crud pattern (DCP) in 40 of the 177 fuel assemblies that was significantly different than the "normal" corrosion pattern. Although the number of failed rods was not unusual, the DCP on the 9 first-burn failed rods, described as a marbled (or variegated) pattern, was unanticipated. This pattern was also observed on 173 other first-burn rods adjacent to the defective rods and in symmetrically equivalent rods in other quadrants of the core. The core quadrant where the most prevalent damage (7 defective rods) and unusual crud pattern occurred had an initial flux tilt of slightly more than + 2% during the previous cycle. The area of the rods exhibiting the failures and abnormal patterns was consistently in the range of 100 to 130 inches above the bottom of the core. Furthermore, the abnormal corrosion patterns and failures were only found on the outside surface of peripheral fuel rods.

On the basis of the initial failures detected by UT, the licensee initiated additional visual and ECT examinations of the 173 fuel rods. No failed rods or rods that indicated any amount of clad thinning (by ECT) were reinstalled in the core. The licensee made a decision that it was acceptable to reinstall rods with the DCP as long as no clad thinning could be measured. Fuel assemblies with nonreusable rods were reconstituted using either stainless steel rods or "donor" rods containing fuel. The examination of 173 rods and reconstitution of 21 fuel assemblies were completed on October 2, 1995. A total of 87 rods were replaced with stainless steel rods, as allowed by License Amendment No. 183 (implementing the provisions of Generic Letter 90-02).

Operating Cycle 10 at TMI-1 had several unique characteristics. These included that the core had the highest reactivity of any core ever designed by B&W, with some fuel rods enriched to as high as 4.75% U-235 (to extend to a 24-month core life) and the core operated for 661 effective full power days (EFPD). Because of the high fuel loading, beginning of core life (BOC) boron concentration had to be 1851 ppm. B&W recommended that lithium concentration not exceed 2.2 parts per million (ppm) for fuel warranty considerations. The resultant pH from these two specified concentrations (boric acid vs lithium hydroxide) was in the range of 6.6 to 6.8 for the first five months of Cycle 10. It was only after the control rod drop time problem occurred in March 1994, that the licensee decided it was necessary to raise Ph to a minimum of 6.9, which is where it remained for the rest of the cycle (requiring lithium concentrations of greater than 2.2 ppm).
The licensee assembled a panel of experts (including B&W, EPRI, Duke Power, and GE) on September 28, 1995 to review all available information, agree on a

most probable root cause of the DCP, and make corrective/preventive action recommendations. The panel and the licensee concluded that most likely the low Ph due to high boron and low lithium concentrations caused the unusual crud deposits in high temperature regions of the core where localized boiling in adjacent hot channels occurred. The licensee has taken additional steps including determining the chemical composition of the crud and measuring the oxide thickness to further confirm the root cause. The panel also recommended that the initial axial power offset during Cycle 11 be monitored to determine if symptoms which occurred in Cycle 10 recur (the initial flux tilt was +2%). The initial axial power offset during Cycle 11 was +0.44%, well below the +2% of the last cycle and the TS limit of 3.81%.

The inspectors observed the fuel inspection activities and monitored the status of the inspections and the licensee management's decision making process. The inspectors also attended the meetings of the panel of experts and an October 12, 1995 meeting between the licensee, B&W and NRC Office of Nuclear Reactor Regulation management in Rockville, Maryland. The inspectors found that the fuel inspection activities were well controlled and that the fuel reconstitution work was performed satisfactorily using NRC approved methodologies, as described in Generic Letter 90-02. The licensee's decision to replace all fuel rods that had cladding degradation was a strong example of management's commitment to begin the operating cycle with no fuel defects.

4.3 Inservice Inspection Activities (Unresolved Item 50-289/95-13-01)

4.3.1 Review of ISI Plan

The inspectors reviewed TMI's Inservice Inspection (ISI) plan to determine if the plan was in conformance with the requirements of the American Society of Mechanical Engineers (ASME) Section XI, and if changes to the schedule were properly documented, approved, and controlled. In addition, the inspectors reviewed several completed examinations, and performed a plant walkdown of in-progress examinations.

TMI is in the first period of its second ten-year interval, and its ISI program is required to meet the criteria of ASME Section XI, 1986 Edition, with no addenda. The inspectors determined that the requirements of ASME Section XI were being satisfied. No omissions were noted in the review of the schedule for this period. TMI maintains the 10 year ISI plan on the GMS2 computer database, and in the ISI Program Manual. Changes to the plan were clearly documented and maintained in the Program Manual, and had undergone appropriate levels of review and approval. ISI/NDE management and technical staff personnel demonstrated strong knowledge of the program requirements, and good control of the program implementation.

One minor deficiency was noted in that the controlled hardcopy of the ISI Plan was dated 1992, whereas the applicable administrative procedure, 6100-ADM-3272.01, "NDE/ISI Services Inservice Inspection Program Development and Implementation," states that the controlled hardcopy should be updated within 90 days of completing the examinations. The GMS2 computer-based schedule is updated on a real-time basis, and was determined to be current. TMI ISI/NDE management personnel indicated that they were aware of the deficiency and were actively working to maintain the hardcopy schedule in conformance with the administrative procedure.

Several examinations of those completed during the current outage were selected for more detailed review of the test data packages. The inspectors determined that these examinations were performed in accordance with approved procedures, and the data packages were complete, properly documented and evaluated. The inspectors also performed a walkdown of in-progress activities associated with ultrasonic testing (UT) of the reactor vessel studs, and OTSG eddy current testing. The activities were determined to be well planned and controlled, and no deficiencies were noted during the walkdown.

4.3.2 ISI Program Management

TMI's methods for managing the ISI program were reviewed by evaluating the adequacy of applicable procedures, contractor oversight, Quality Assurance/ Quality Verification (QA/QV) aspects, and self-assessments. The ISI Program Manual was reviewed, including the applicable procedures that control the program.

The ISI Program Manual was found to be well written and comprehensive, and TMI's procedures for ensuring that ISI personnel were adequately qualified to perform the required examinations were good. TMI procedure 5361-ADM-7230.01, "Nondestructive Examination Personnel Qualification and Certification," establishes the minimum requirements for the qualification and certification of TMI NDE personnel, and Procedure 6250-PGD-2741, "Nondestructive Examination Training Program Description," provides for orientation and continuing training for NDE technical and management personnel. These procedures were reviewed and determined to be consistent with regulatory requirements.

TMI demonstrated good oversight and control of contractor activities in performing ISI. In particular, the inspectors reviewed procedures associated with ensuring that contractor personnel were adequately qualified to perform NDE/ISI activities. These procedures ensure that contractor personnel meet essentially the same minimum requirements as TMI ISI/NDE personnel, and also require that contractor personnel demonstrate their abilities through a proficiency test. The inspectors concluded that the procedures were well written and comprehensive, and were being properly implemented.

TMI's QA/QV oversight of the ISI program and documented internal assessments were well done, and cognizant TMI personnel took appropriate action in acknowledging and responding to deficiencies noted in the assessments. The Nuclear Safety Assessment (NSA) section performs biannual comprehensive reviews of the ISI program, and QA personnel perform periodic monitoring of specific ISI activities throughout the operating cycle. The inspectors reviewed the most recent NSA assessment and the documented findings of several QA monitoring activities. The results of all of the assessments were generally positive, with some minor weaknesses and deficiencies. Where weaknesses or deficiencies were noted, TMI took appropriate action to correct the problem and prevent recurrence.

4.3.3 Once Through Steam Generator Eddy Current Examinations

The eddy current (EC) testing program for the TMI OTSGs from the 11R outage was reviewed. The review covered the verification of program implementation consistency with Technical Specification (TS) requirements and the NRR approved inspection plan, and the appropriateness of the test program probes used, locations examined, and disposition of inspection findings.

The inspection was consistent with TS requirements and the NRR approved inspection plan. In accordance with the inspection plan, 21 percent of over 15,000 tubes in each SG were examined. The initial 3% batch of tubes were randomly selected for the purpose of remaining consistent with the TS requirements. The remaining tubes inspected for the same purpose were chosen randomly from a pattern of pre-selected tubes consisting of straight line arrays across the tube sheet in a direction parallel to the inspection lane of the tube sheet. Although not completely random, the randomness is restricted to within the population of pre-selected rows of tubes. The extent of tube data acquired is from tube end to tube end, but evaluation included tubes between expansion transitions in the upper and lower tube sheets.

The inspection of 21 percent of the tubes adequately satisfies the TS requirements (assuming the number of tubes found defective did not require examination of all tubes). Inspection speed of 40-44 inches per second (ips) was an increase over the previously used 24 ips. The quality of data was fairly good. The locator frequency was increased from 10 Khz (used at other plants) to 45 kHz to reduce tube support plate distortion. A .510 inch diameter magnetic bias probe is used for normal inspection, and a .540 probe is used for retesting if indications are found.

A sampling of 280 tubes per OTSG were inspected at the top of the tube sheet to above the expansion transition region using the 3 coil motorized rotating pancake coil (MRPC). Twenty-seven randomly distributed single volumetric indications (non-crack-like) were in OTSG 'A'. These were dispositioned using the .540 diameter bobbin, of which many were not detectable with bobbin inspection. Tube wear indications were also inspected with the 3 coil MRPC. Half the tube sleeves were inspected using the plus point probe in the transition region and a small sample of Westinghouse plugs were inspected to test this method. No indications were found. All the B&W Inconel 600 plugs were inspected in the hot leg using a single rotating pancake coil.

TMI is using a voltage criteria for dispositioning the defects. Inspector discussions with the Office of Nuclear Reactor Regulation (NRR) indicated that the use of this criteria has not been approved by NRR. This matter is presently under study and is considered an unresolved item **(50-289/95-13-01)** until NRR can fully assess the use of this technique at TMI.

The inspection results showed that 1 pluggable tube was found in Unit 'A' OTSG and 5 pluggable tubes were found in Unit 'B' OTSG. Also, 3 newly degraded tubes were found in Unit 'A' and 6 newly degraded tubes in Unit 'B'. In accordance with the TS, TMI is required to notify NRC within 15 days of the tubes removed from service. The completed OTSG tube inspection report will be published within 12 months.

A number of deficiencies were found in the Data Analysis Guidelines. These included the fact that no degradation type history is given, no noise criteria is given, no figures are incorporated in the text, no OTSG physical description is given, and readable reference standards are not included. Based on discussions with TMI personnel, these deficiencies were determined not to have an effect on the recent EC examinations. The licensee indicated that they would review the guidelines for improvement prior to performing future examinations.

4.3.4 Conclusions

The inspectors found that TMI's ISI plan is consistent with the requirements of ASME Section XI, and ISI/.JDE management and technical staff personnel demonstrated strong knowledge of the program requirements, and good control of the program implementation. Completed and in-progress activities which were reviewed during the inspection were determined to be well planned and controlled, with no deficiencies noted.

The ISI Program Manual was found to be well written and comprehensive, and TMI is properly implementing the applicable ISI procedures. TMI demonstrated good oversight and control of contractor activities in performing ISI, and the self-assessments of the ISI program were well done.

TMI's performance during eddy current examinations of the steam generators was good. However, for dispositioning some indications, TMI is using a voltage-based criteria which has not been approved by NRR. This matter is considered an unresolved item **(50-289/95-13-01)**. A number of deficiencies were found in the Eddy Current Data Analysis Guidelines, which the licensee indicated they would address prior to future examinations.

4.4 (Closed) Unresolved Item (50-289/94-08-01) Missed ISI Examination for Pressurizer Spray Relief Valve

The inspectors reviewed TMI's response to unresolved item 50-289/94-08-01, concerning missed ISI examinations on pressure-retaining bolting on pressurizer spray relief valve RC-V-1 during the first ten year interval. TMI's review of this issue determined that the root cause of the missed examinations was that, in the 1974/1975 time frame, a bolted bonnet valve was installed in place of a non-bolted unibody style valve, and no record was made of this exchange. Because the original valve style had no pressure-retaining bolting, there was never an ISI bolting examination required. The error was ultimately identified by TMI.

In order to verify that there were no similar problems with other valves, TMI performed a review of all valves in ASME Section XI Class 1 and 2 non-exempt systems. This review identified several examples of not having, or not retaining, documentation of pre-service examinations, and lack of attention given to reflecting changes in the configuration control system. These examples all occurred during the first ten year interval. No discrepancies were noted during the review of second interval ISI examinations. TMI's review of the issue concluded that these types of problems are less likely to occur today because of changes implemented in the computerized database which tracks component ISI, employee training, and tracking of component maintenance schedules. Further ameliorating the significance of the issue is the fact that bolt examinations for this valve size are no longer required by the ASME Section XI Code. Based on the information above, this unresolved item is closed.

4.5 (Closed) Unresolved Item (50-289/95-06-01) Unrestrained Temporary Equipment in the Control Room

During a routine inspection of the control room on April 10, 1995, the inspectors noted that several pieces of unrestrained temporary equipment were in close vicinity to the reactor protection system (RPS) cabinets and the Liquid Waste Disposal System panel. The location of the equipment did not appear to be within the guidelines of enclosure 2 of General Maintenance Procedure (GMP) 1401-18, "Equipment Storage Inside Class 1 Buildings." The inspectors expressed concern that the unrestrained temporary equipment could potentially impact safety-related equipment during a seismic event. The temporary equipment included printers, printer stands, and small filing cabinets. The licensee documented the concern on Capture Form No. 95-76 for evaluation and subsequently validated it. The inspectors found the licensee's immediate corrective actions to be acceptable. However, initially, the licensee did not thoroughly address the root cause of the issue and therefore did not identify sufficient actions which could reduce the probability of event recurrence.

The inspectors reviewed this issue at the end of the 11R refueling outage. The licensee had revised GMP 1401-18 to provide additional guidance regarding seismic concerns and to include the control room as a location where temporary equipment could be stored. Operations Surveillance OPS-S314, "Loose Equipment Inside Class 1 Buildings," and the Equipment Storage Log for Class 1 Buildings were also revised to include the control room. The inspectors found these procedure changes to be acceptable. The licensee performed walkdowns of the class 1 structures prior to plant startup. The inspectors found the walkdowns to be very thorough as exemplified by the changes made by plant engineering to the Equipment Storage Log for Class 1 Buildings. Based on the walkdowns, engineering improved the log by including a detailed checklist which listed the equipment temporarily stored in the buildings, and Equipment Storage Data Sheets (ESDS) for each piece of equipment. The ESDS provide written documentation of the appropriate temporary storage methods for the equipment. The licensee had completed the documentation in the log for the Reactor Building and was in the process of completing the documentation for the other class 1 buildings at the end of this inspection. Also, the inspectors conducted walkdowns of the Reactor Building, the Control Room, the Auxiliary Building and the Intermediate Building prior to plant startup and found no issues with the storage of unrestrained temporary equipment. The inspectors found the corrective actions taken by plant engineering to be excellent.

The unrestrained temporary equipment identified by the inspectors in the control room in April 1995 was of minimal safety significance, although, it did not meet the storage guidelines required by GMP 1401-18. The inspectors found the procedure revisions and the actions taken or planned to be taken by the licensee to improve the Equipment Storage Log for Class 1 Buildings to be sufficient to reduce the probability of event recurrence. Therefore, the failure to follow GMP 1401-18 is being treated as a non-cited violation, consistent with section IV of the enforcement policy. In addition, the unresolved item is closed.

4.6 Followup of Emergency Preparedness Drill Improvement Areas

NRC recommendations for areas of potential improvement noted in Inspection Report (IR) 50-289/95-05, "TMI Emergency Preparedness" were reviewed. It was noted in the IR that Technical Support Center (TSC) personnel were unable to correlate the available radiation level data to determine that the 'B' OTSG had a primary-to-secondary leak. TSC engineers had difficulty interpreting the radiation monitoring information available to them via the on-line dose assessment computer displays. While this did not detract from the overall strong performance of TSC personnel, it was considered an area for potential improvement.

In response to this recommendation, TMI initiated an Emergency Plan Action Item 950066. The licensee stated that TSC personnel did note that both OSTGs were leaking and observed that nearly all the leakage was from OSTG 'B'. OSTG 'A' was isolated at the same pressure as the RCS. The ratio of leakage between the OSTGs was not reported since it was not perceived to be a request made to TSC. TSC personnel were keenly aware of the need for aggressively pursuing responses to requests from the Emergency Director. It is recognized that the TSC should have determined the leak rate ratio because both OSTGs were suspected of leakage. The methods and importance of evaluating the second OSTG for leakage will be included in the "Lessons Learned" portion of Emergency Preparedness Requalification Training for the TSC engineers.

Subsequent to the NRC inspector noting that TSC engineers had difficulty interpreting the dose assessment displays, dose assessment computer displays have been made available to TSC as part of a continuing upgrade of information flow. Training on the content and format of the displays is scheduled for selected TSC personnel. The corrective action program has shown that direct steps have been taken by TMI in response to NRC recommendations.

5.0 PLANT SUPPORT (71750, 71707, 83750)

5.1 Radiological Controls (Violation 50-289/95-13-02)

The licensee's radiological controls program was reviewed during the refueling outage for Unit 1. Areas reviewed included: audits and appraisals; changes to the program; training and qualifications of personnel; external exposure control; internal exposure control; control of radioactive materials and contamination, surveys and monitoring; maintaining occupational exposures as low as is reasonably achievable (ALARA); and effectiveness of licensee controls. The inspection also included a review of previously-identified items.

5.1.1 Audits and Appraisals

Nuclear Safety Assurance (NSA) audits conducted since the last radiological controls inspection were reviewed. One NSA audit had just been completed and evaluated the radiological controls program for the period from June 7, 1995, through August 24, 1995. The auditors concluded that most activities were being performed in accordance with sound radiological principles and were in compliance with applicable regulations and requirements. Five minor deficiencies were identified in various areas and the auditors stated that the Radiological Controls Department was not adequately implementing the GPU Nuclear corporate requirements for corrective action programs. Specifically, the auditors noted that trending of deficiencies and adequate corrective actions for deficiencies identified from trends was not always documented and evaluated. The licensee had not yet completed the evaluation or corrective actions for these identified deficiencies. The licensee's progress in this area will be reviewed in future inspections.

The licensee also recorded radiological incidents and poor radiation worker practices. The inspector reviewed the 1995 radiological incident reports (RIRs) and radiological awareness reports (RARs) and concluded that the licensee had generally taken appropriate and timely corrective actions for each identified incident or deficiency. However, the inspector was concerned regarding two RIR's involving violations of licensee procedures. One RIR documented a violation of the licensee's procedures regarding controls for radiography operations. On September 6, 1995, an auxiliary operator (AO) violated a radiography posting and barrier and entered an area in which radiography was being performed. The source was not exposed at the time and the AO received no exposure from the device. While the exposed source would generate a dose rate of about 390 rem per hour at one foot, potential exposure of the AO was further minimized by the fact that: (1) the source is under constant visual surveillance by the radiographer when radiographic activities are in progress (in fact, the radiographer intercepted the AO long before he approached the source); and (2) the AO was wearing an electronic alarming dosimeter that would have provided warning of a high dose rate. The AO had an actual exposure of approximately 1 millirem for the entry. The violation was identified by the licensee contractor radiographers and the licensee ISI engineer at the work site, who checked the radiography postings and boundaries and attempted to inform health physics personnel before resuming work. However, the licensee and contractor employees did not inform either the shift supervisor or other responsible management of the radiography area boundary violation, in order to ensure adequate immediate correction of the problem, before resuming radiography operations. Near term corrective actions, subsequent to the radiography operations, included counseling the AO and informing workers of the occurrence. A longer term corrective action was to review the use of postings for possible improvements. However, the licensee had not committed to any other long-term or corrective measures designed to prevent recurrence of this type of event, such as other controls and reinforcement of the requirement to adhere to radiological controls procedures and postings. Subsequent to discussions with the inspector, the licensee amended the RIR to include a review of the licensee's procedure (6610-ADM-411.07, "Radiography Operations") for potential changes, including a documented review of all controls for each radiography operation prior to the start of the job. In summary, the licensee's problem identification and correction process was considered inadequate, in this instance, because: (1) the shift supervisor or other responsible licensee management was not provided an opportunity to exercise management oversight and review of the occurrence prior to the resumption of radiography operations, and (2) originally determined long-term corrective actions were limited only to review of use of postings for improvements. Since the immediate and long-term corrective actions taken for this event were not sufficiently comprehensive and were considered inadequate to prevent a recurrence of the violation, this violation is cited in accordance with the NRC enforcement policy (**VIO 50-289/95-13-02**).

The second violation of licensee procedures involved the release of radioactive contaminated equipment from the radiological controlled area and eventual shipping of the material via common carrier to a vendor in Georgia. The licensee was informed by the vendor that they had found elevated levels of nonremovable contamination on several pieces of equipment. The licensee took excellent corrective actions including calculation of the applicability of radioactive material classification as per Department of Transportation (DOT) regulations, sent a qualified technician to the vendor's location to verify the contamination, transported the equipment back to the licensee's facility, and documented the survey results. The licensee's investigation revealed that an error was made by the technician when the material was surveyed prior to final release from the radiological controlled area. Although a release survey had been performed, the survey had not been documented. This was in violation of the licensee's Procedure 6610-ADM-4200.02, "Release Surveys," which required documentation for this type of radiological survey. The licensee also implemented other corrective actions, including training for all technicians and emphasis on the correct use of the procedure regarding required documentation for release surveys. In conclusion, since the contaminated material did not exceed the definition of radioactive material (RAM) as per 49 CFR 173.403(y), the failure to adhere to radiological controls procedures for release of materials constituted a violation of minor consequence and is being treated as a non-cited violation, consistent with Section IV of the NRC Enforcement Policy.

5.1.2 Changes in the Radiological Controls Program

The licensee had made some personnel reassignments since the last NRC inspection of the radiological controls program. These changes included the return of two radiological controls technicians who were temporarily reassigned as radiological support technicians in the Radiological Health and Occupational Safety group. These technicians had assisted in processing the workers for the refueling outage in September 1995. Activities included operating the whole body counting system and respirator fit testing equipment. The technicians were returned to their normal job assignment during the refueling outage. The licensee regarded the temporary assignment as very successful and may continue to utilize the technicians for future assignments.

Other changes to the organization included temporary staffing for the refueling outage. The licensee had augmented their normal staff of approximately 33 radiological controls technicians with 35 contractor technicians, 4 radiological controls technicians from Oyster Creek, and 16 chemistry technicians. The inspector reviewed the training and qualification documentation for these individuals for their temporary duties. The training provided to the technicians was very detailed and included appropriate information from theory to actual operations. The documentation of the training and job qualifications was adequate, and the inspector did not find any discrepancies. However, the inspector noted that the licensee's procedures did not specify the frequency for requalification of contractor technicians. The licensee typically requalified technicians who had not been qualified at a GPU Nuclear site in the last two years. Interviews with and observations of the technicians by the inspector revealed a good working knowledge of their job tasks and limitations. The inspector concluded that the technicians were well qualified to perform these job duties.

5.1.3 Exposure Control

The inspectors reviewed the licensee's external and internal exposure controls through interviews with various licensee personnel, review of documentation, and observation of work in radiological areas.

5.1.3.1 Planning and Preparation for Outage Work

The inspectors' reviews indicated that the planning and preparation for refueling outage work was very good, including management support of planning meetings. The inspector observed specific job planning meetings, pre-job briefings, and general outage planning and coordination meetings. The planning and preparation for the spent fuel pool transfer mechanism repairs was excellent and included important considerations for spent fuel pool diving evolutions. The radiological engineering staff and various general radiological controls supervisors were involved in outage planning with various other groups from the facility. Planning involved radiological and engineering controls to ensure that personnel radiation doses were maintained as low as is reasonably achievable (ALARA). Respirator use was evaluated for certain jobs to ensure that the total dose (sum of internal and external dose) was not higher with the use of a respiratory protection. The staff was also gathering data on the workers' efficiencies when respirators were worn, versus when they were not worn, for the same job or similar conditions. Overall, the inspectors found that the planning process was very good and included several initiatives to maintain personnel exposures ALARA. Appropriate emphasis was placed on jobs or activities with potentially higher dose rates or larger integrated total dose.

5.1.3.2 External Exposure Controls

The inspectors observed workers in the RCA wearing their assigned alarming self-reading dosimeter (ASRD) and the whole body thermoluminescent dosimeter (TLD) with the correct body placement. A new computerized access control system had been implemented prior to the outage that incorporated the use of the ASRD. The workers were very familiar with the system, and no problems were noted. The licensee had an on-site laboratory to process whole-body TLDs. The laboratory is currently accredited through the National Voluntary Laboratory Accreditation Program (NVLAP).

High radiation area (HRA) and very high radiation area (VHRA) postings and barriers were checked throughout the facility. Areas were appropriately posted and barricaded as required by NRC regulations. Some minor discrepancies in postings were identified by the inspectors, and the licensee's staff took immediate corrective actions. The licensee had recently made changes to various HRA barriers in an effort to make the barriers more effective. Some barriers in the reactor building were bolted to the floor to prevent them from being inadvertently moved. Other barriers had been replaced with new stanchions that were specifically designed for this application. All areas that were required to be locked were appropriately maintained by the radiological controls staff. The inspectors verified that these areas were locked and posted, as required by the licensee's commitments.

In summary, external exposure controls were good with some improvements noted in the maintenance of high radiation area barriers.

5.1.3.3 Internal Exposure Controls

The inspectors reviewed the equipment used for assessing intakes of radioactive materials and the records associated with those assessments. The licensee used air sampling equipment in the work place to determine a calculated dose assessment for the worker based on stay time in the specific area After an individual was assigned a committed effective dose equivalent greater than 10 millirem in any day or 50 millirem in any consecutive 7-day period, then a whole body count (or other type of bioassay) was required. The inspectors noted representative air sampling in the RCA where appropriate and appropriate use of ventilation and filtration systems. Air sampling equipment was properly maintained and was within calibration requirements.

The licensee had a computerized system for assigning and tracking dose assignments derived from air samples. The inspectors noted that the tracking system was adequate and there were no individuals with an internal dose assignment for 1995 greater than 50 millirem. In summary, the inspectors concluded that internal exposure control was very good with continuing improvement noted in the radiological controls program.

5.1.4 Control of Radioactive Materials and Contamination, Surveys and Monitoring

The inspectors reviewed the control of radioactive materials and contamination, surveys and monitoring through tours of the facility, reviews of documentation, and interviews with various licensee individuals.

Control of radioactive material and contamination was generally good, though some areas exhibited poor housekeeping in contaminated areas. The licensee had posted areas with potential contamination and required protective clothing in contaminated areas. Step-off pads were used by workers as they exited the contaminated areas. Housekeeping in contaminated areas was generally good, but some areas had cords or other items crossing the contaminated area boundaries without a tie-down or tape to help prevent the spread of contamination. Other areas were not well maintained, and used personnel protective clothing or trash was found laying in the potentially contaminated areas.

The inspectors observed the licensee's tagging and labelling of radioactive materials in the restricted area. Items generally were tagged or labelled as appropriate including information such as dose rates, contents, and dates of survey. Improvement was noted in the tagging and labelling of radioactive materials since previous refueling outages.

The inspectors also verified that current radiological survey data was used during job planning. Radiological information and current survey data was posted for workers at the entrances to the restricted area.

In summary, the licensee provided good controls for radioactive materials and contamination, surveys and monitoring. Improvement was noted in the tagging and labelling of radioactive materials. No major deficiencies or violations of regulatory requirements were identified.

5.1.5 Other Radiological Control Program Items

The inspectors reviewed items that had been previously identified to determine the licensee's progress in implementing corrective actions or appropriate radiological controls. These items included frisking personnel for contamination when leaving the restricted area,

5.1.5.1 Frisking Personnel for Contamination

The licensee's staff had made some improvements at the main exit from the RCA to prevent a recurrence of problems with personnel monitoring for contamination (see NRC Inspection Report No. 50-289/95-09). Since the time of the previous NRC inspection, the licensee's staff had reconfigured the exit to clearly delineate the entrance and exit from the radiological controlled area. This change allowed workers to enter and exit without crossing paths and prevented the potential spread of contamination. In addition to remote surveillance cameras, a remote alarm was installed at the main control point to alert technicians to a potentially contaminated individual. The frisking station for hand carried items was also relocated to help prevent the unintentional spread of contamination. Notwithstanding the improvements in the facility, the licensee continues to identify problems with personnel monitoring. This area of the radiological controls program will be reviewed in future inspections.

5.2 Security

The inspectors monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspectors observed security staffing, operation of the Central and Secondary Alarm Stations, and licensee checks of vehicles, detection and assessment aids, and vital area access to verify proper control. On each shift, protected area access control and badging procedures were observed. In addition, protected and vital area barriers, compensatory measures, and escort procedures were routinely inspected.

The inspectors concluded that, for those areas inspected, the Security Plan was being properly implemented.

6.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (71707)

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and areas of concern to the NRC. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting with licensee management on November 8,1995 summarizing inspection activities and findings for this report period. Licensee comments concerning the issues in this report were documented in the applicable report section. No proprietary information was identified as being included in the report.

6.1 Meeting With GPU Nuclear Corporation Regarding Fuel Clad Concerns

On October 12, 1995, a public meeting was held between the NRC and GPU Nuclear Corporation at the NRC Headquarters Office in Rockville, Maryland. The purpose of the meeting was to discuss the cause and safety implications of the distinctive crud pattern observed on several fuel rods during the 11R refueling outage. The details of the meeting were documented in a separate letter that was issued on October 20, 1995.

6.2 Enforcement Conference With GPU Nuclear Corporation Involving Apparent Security Violations

On October 25, 1995, a predecisional enforcement conference was held to discuss the events involving security breaches of the protected area boundary during planned maintenance activities. The details of the security event are documented in NRC Special Inspection Report No. 50-289/95-15, dated October 11, 1995. The closed meeting was held between the NRC and GPU Nuclear Corporation at the NRC Region I Office in King of Prussia, Pennsylvania. The purpose of the meeting was to obtain information to enable the NRC to make an enforcement decision, such as understanding of the facts, root cause(s), missed opportunities to identify the apparent violation sooner, corrective actions, significance of the issues and the need for lasting and effective corrective action. The details of the meeting will be documented in a separate letter that will be issued from the NRC Region I Office.