U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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License No.	DPR-50
Licensee:	GPU Nuclear Corporation P.O. Box 480 Middletown, PA 17057
Facility:	Three Mile Island Station, Unit 1
Location:	Middletown, Pennsylvania
Inspection Period:	March 1, 1994 - April 4, 1994
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Approved by: John F. Rogge, Chief — 4/20/94 Date
Reactor Projects Section No. 4B

Inspection Summary

The NRC Staff conducted safety inspections of Unit 1 power operations. The inspectors reviewed plant operations, maintenance, engineering, radiological controls, and security activities as they related to plant safety.

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

EXECUTIVE SUMMARY
Three Mile Island Nuclear Power Station
Report No. 50-289/94-04

Plant Operations

The licensee's planning for and conduct of the shutdown to repair the pressurizer spray valve were effectively performed and judged as a strength. Management involvement in the entire process was also a strength. However, the licensee's initial attempt at stopping the body-to-bonnet leak by torquing the fasteners at power with no isolation was unnecessarily hazardous, because any significant increase in leakage would have presented a high risk to personnel and the plant since the valve would have been difficult to isolate.

The licensee's operations staff was strongly involved in the development of the procedure and safety evaluation for returning the pressurizer spray line to service. The licensee returned the line to service in a cautious, controlled manner and the condition of the pressurizer and pressurizer components was not degraded.

The licensee's corrective actions involving an incident where both decay heat closed cooling water heat exchangers were simultaneously isolated/bypassed were adequate to prevent recurrence of a similar incident.

Maintenance

The licensee's efforts in maintaining a very low reactor coolant system leak rate assisted them in quickly identifying the spray valve leak and is considered a strength.

The licensee's performance was weak in that they failed to properly implement their procedure change approval process. If the licensee had properly implemented the process, they may have identified that a change in an emergency feedwater (EFW) surveillance procedure resulted in the isolation of the common recirculating line for all three EFW pumps. Without timely manual action, this could have resulted in the total loss of EFW. This violation will not be subject to enforcement action because the licensee's efforts in correcting the violation met the criteria specified in Section VII.B of the Enforcement Policy.

The licensee's repair of the pressurizer spray valve was well conducted.

Engineering

The depth and scope of the licensee's inspection effort to determine if conditions similar to the degradation of the pressurizer spray valve, caused by boric acid corrosion, existed which could reduce the integrity of the reactor coolant system boundary was satisfactory. The licensee initiated a Plant Experience Report to further assess the root cause of the leak and additional NRC inspections of the root cause will be performed. In addition, the licensee's program for prevention of boric acid corrosion will be the focus of additional inspection activities by the NRC.

The licensee's re-testing of the control rod drives following the March 17, 1994 shutdown was a positive initiative, since there was no regulatory requirement to do so, and it enabled the licensee to identify that the drop times on 12 control rods exceeded the Technical Specification limit. However, the licensee could have been more conservative had they chosen to disassemble and inspect one of the control rods to determine the root cause of the increased drop times. The licensee's evaluation to support an increase in the allowable rod insertion time for all rods combined with a probable root cause did allow us to determine that minimal risk to public health and safety existed. The licensee's commitment to resolve the issue is contained in Confirmatory Action Letter 1-94-004, dated March 29, 1994.

The licensee should have been more aggressive in evaluating the potential radial bearing misalignment on the generator end bearing for the 'B' emergency diesel generator. The failure of certain bearing vibration frequencies to die out when the diesel reaches thermal equilibrium shows that there may be a misalignment problem.

The licensee and NRC determined that the reactor coolant system thermowells are operable even though they exceed the allowable shear stress of ASME B31.7 and ASME Code Section 2III. However, the NRC determined that having components with sheer stresses which exceed the allowable is not conservative and is currently preparing an Information Notice.

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1.0 SUMMARY OF FACILITY ACTIVITIES

1.1 Licensee Activities

At the beginning of the period, Unit 1 was operating at 100% power. On March 7, 1994 the licensee reduced reactor power to about 75%, following the identification of a body-to-bonnet leak on the pressurizer spray valve. The unit was shutdown on March 17, to repair the valve. Following the shutdown, control rod drive drop testing was performed, and the licensee found that 12 control rod drives had excessive drop times. The unit was restarted on March 26, following resolution of the control rod drop time issue. At the end of the period, the unit was operating at 100% power.

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. The inspectors obtained information through actual observation of licensee activities, interviews with licensee personnel, and documentation reviews.

The inspectors observed licensee activities during both normal and backshift hours: 64 hours of direct inspection were conducted on backshift. The times of backshift inspection were adjusted weekly to assure randomness.

2.0 PLANT OPERATIONS (71707, 92702)

2.1 Operational Safety Verification

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

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

The inspectors observed plant conditions through control room tours to verify proper alignment of engineered safety features and compliance with Technical Specifications. The inspectors reviewed facility records and logs to determine if entries were accurate and identified equipment status or deficiencies. The inspectors conducted detailed walkdowns of accessible areas to inspect major components and systems for leakage, proper alignment, and any general condition that might prevent fulfillment of their safety function.

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

2.2 (Closed) Violation (VIO, 50-289/93-09-01) Decay Heat River Isolated to the Decay Heat Closed Cooling Water Heat Exchangers

This item concerned a January 28, 1993, incident where an Auxiliary Operator (AO) isolated and bypassed the decay heat river water (DR) supply to the decay heat closed cooling water (DHCCW) heat exchangers, DC-C-2A/B, for approximately 2 hours and 55 minutes while performing OPS-S227, "DR-P-1A/B Periodic Surveillance." The purpose of OPS-S227 is to operate both DR pumps at least one hour per week to minimize the silt build-up under the pump suction bowls. OPS-S227, step B, states that if necessary to reduce the temperature transient on decay heat removal (DHR) system and DHCCW system, bypass the DHCCW heat exchangers by positioning the valves listed. The AO performed this step as written, which simultaneously isolated and bypassed the river water supply (DR) to both DHCCW heat exchangers. The purpose of Step B was to avoid the extreme cooling of the DHR and DHCCW systems during the early 1980s when Unit-1 was in an extended shutdown and the core decay heat levels were extremely low. The option to bypass the coolers has not been needed since the restart of Unit-1 in 1985, after the six year shutdown.

The licensee determined that the root cause of this event was personnel error. The AO failed to operate the equipment in accordance with Administrative Procedure (AP) 1029, "Conduct of Operations," which would have required authorization from the Shift Supervisor, Shift Foreman, or Control Room Operator prior to manipulating the valves. The licensee also determined that to a lesser extent, the clarity of procedural guidance also contributed. The instructions in OPS-S227 did not provide guidance for determining if a thermal transient would occur, and did not specify that only one cooler at a time should be bypassed and that bypassing a cooler rendered the train out of service and started a Technical Specification time clock. The step that bypasses the coolers should have been eliminated since it has not been applicable since 1985.

OPS-S227, as well as all other Operations Surveillances, are not required by Technical Specifications and are generally used for data collection. Administrative Procedure 1016, "Operations Surveillance Program," step 4.2.2, states that in general, detailed procedural guidance for evolutions which can potentially affect safe and/or reliable plant operation should be contained in approved Plant Operating Procedures. Plant Operating Procedures are covered by Administrative Procedure 1001A, "Procedure Review and Approval," which implements all Quality Assurance Plan requirements for procedure review and approval. Prior to this incident, to meet the requirements of Technical Specification 6.8.1 concerning procedures, the licensee had changed AP 1016 to require that certain safety related Operations Surveillances be reviewed by the PRG and approved by the Plant Operations Director and the Director of Operations and Maintenance. Although AP 1016 required the same review and approval for these safety related Operations Surveillances as are required for Operating Procedures, the licensee only performed informal periodic reviews of these

Operations Surveillances. As a result, actions in the Operations Surveillance procedures that have the potential to affect safe plant operations did not receive a biennial review. Although OPS-S227 was approved by the Plant Operations Director, the Plant Review Group Chairman, and the Director of Operations and Maintenance in March 1992, this review was not sufficiently detailed to determine that OPS-S227, Step B was unclear and was no longer applicable.

The inspector verified that the licensee had adequately completed the corrective actions listed in the violation response which included: 1) AP 1006 was revised to exclude from the Operation Surveillance Program tasks that operate a system or component outside the envelope of the approved Operating Procedure; 2) Operations Surveillance Procedures similar to OPS-S227 were revised to ensure that detailed procedural guidance for evolutions that can potentially affect safe plant operations are removed and placed in approved Operating Procedures; and 3) Each operating crew reviewed this event to ensure their understanding of the errors that were committed and how similar errors can be avoided.

The inspector found that the licensee's corrective actions are adequate to prevent recurrence of a similar incident. This item is closed.

3.0 MAINTENANCE (61726, 62703, 71707)

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 trade; 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 (JO) No. 081234, "Radiation Monitor Tie-In to Plant Computer."
- Preventive Maintenance Procedure E-107, "Conduct of Infrared Thermography," on emergency diesel generator 1A.
- Job Order No. 085212, "RC-V-1 has a bonnet leak. Retorque bonnet studs to stop leakage."
- Job Order No. 085210, "RC-V-1 Body-to-Bonnet Leak."

The inspector had no concerns with the conduct of JO 081234 or infrared thermography on the emergency diesel generator. JOs 085212 and 085210 involving the pressurizer spray valve, RC-V-1, are further discussed in Section 4.1 of this report.

3.2 Surveillance Observations

The inspectors observed 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. The inspectors 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 (SP) 1300-5R, "EF Hydrostatic Test for Inservice Testing."
- Surveillance Procedure 1302-3.1, "Radiation Monitoring System Calibration."
- Surveillance Procedure 1302-3.1B, "RM-L-6 and RM-L-7 Liquid Monitor Calibration."
- Surveillance Procedure 1303-11.1, "Control Rod Drop Time."

The inspector had no concerns with the performance of SP 1302-3.1 and 1302-3.1B. The inspector had several concerns with a change made to SP 1300-5R which is described in Section 3.3. Activities associated with control rod drop time testing are discussed in Section 4.2.

3.3 Isolation of Emergency Feedwater Pump Recirculation Line

On August 30, 1993, the licensee reviewed and approved Temporary Change Notice (TCN) 1-93-0055 to Surveillance Procedure (SP) 1300-5R, "EF Hydrostatic Test for Inservice Testing." The purpose of the change was to allow the performance of the test at power, because the test was written to be performed at a reactor coolant system (RCS) temperature of less than 250°F. The test was performed successfully on September 1, 1993. During a review of a proposed change to SP 1300-5R to permanently incorporate this testing method, the licensee found that the test closed CO-V-176, which isolated the common emergency feedwater (EFW) pump recirculating flow path for all three EFW pumps. During this test, the turbine driven pump was in a tripped condition, but the two motor driven pumps would have started and the valves that control once-through-steam-generator (OTSG) level were operable. With the recirculation path isolated, the licensee was concerned that the motor driven pumps could have been dead-headed if an EFW actuation had occurred during the 36 minutes it took to perform the test. The licensee contacted the pump manufacturer who stated that the pumps would last for approximately one minute dead-headed (no flow.)

On January 28, 1994, the Plant Review Group met to perform an operability determination and a reportability determination. All three EFW pumps discharge to a common header. Off of this header, flow to the 'A' OTSG is controlled by parallel valves EF-V-30A and 30D and flow to the 'B' OTSG is controlled by parallel valves EF-V-30B and 30C. The Heat Sink Protection System (HSPS) controls the position of EF-V-30A/B/C/D to maintain OTSG level. The system is designed such that if there is an EFW actuation signal and OTSG level is greater than the HSPS controlling level, EF-V-30A/B/C/D will remain closed and the recirculation flow would sustain a minimum flow of 84 gpm through each EFW pump. The PRG determined that even with the recirculation flow path isolated, there would still be flow through the motor driven EFW pumps (turbine driven was tripped) due to the bearing cooling water system. All three EFW pumps are provided with a cooling water system that provides 5 to 10 gpm of feedwater from the EFW pump discharge, through the EFW pump bearings, and back to the suction of the EFW pump. Since the pump manufacturer did not account for this 5 to 10 gpm flow when they stated that the pump would fail in approximately one minute, the PRG asked Technical Functions to evaluate the time before pump failure.

Technical Functions and the PRG determined that there would be sufficient time for operators to realign the EFW system before pump failure. Technical Functions determined that without empirical test data it is impossible to accurately quantify the operating life of a dead headed pump. However, Technical Functions could calculate the operating time required for flashing in the pump and the pump design could be examined to predict the relative susceptibility to flashing. The licensee calculated that the minimum operating period before the pump will flash is 2.6 minutes. This calculation value does not factor in flow out the pump stuffing box, radiation or conductive heat losses and assumes the minimum recirculation flow of five gpm. On the basis of engineering judgement and related experience, the licensee determined that the operating period before flashing would be closer to 5 minutes. After pump flashing occurred, Technical Functions estimates that the pump would remain operable for a time period in the order of minutes. However, there is no known test data to precisely quantify this time.

The PRG then evaluated the amount of time to restore the EFW system alignment. The TCN required the test personnel to establish communications with Control Room personnel and instructed the personnel in the test area to open the hydrostatic test boundary valves to place the system in the normal operating condition if the need for EFW occurs. By procedure, one operator and one engineer were in the immediate vicinity of the EFW pumps for the entire duration of the hydrostatic test. Each Operations Department Engineer involved with the test was interviewed on the specific details of the valves isolated and the requirements to supply EFW. The PRG determined that each engineer clearly knew as a result of the procedure steps the need and timeliness to restore EFW. The engineers conducted independent walkdowns of system restoration and could perform the tasks in less than 5 minutes. One engineering walk through was conducted in two minutes and 35 seconds and the other, using a 30 to 60 second delay time to respond, was completed in an additional 2.5 minutes. NUREG 1022 Supplement 1, "Licensee Event Report System," states that a safety system must operate long enough to complete its intended safety function. Reasonable operator action to correct minor problems may be considered, however, heroic actions and unreasonably insightful diagnoses, particularly during stressful situations, should not be assumed. The PRG concluded that the pump remained operable since the manual actions required were neither heroic nor unusually insightful since the procedure specified the required actions, and the actions would have been performed within the allowed time frame. Therefore, the PRG determined that this event was not reportable.

The inspector reviewed the licensee's calculation concerning the amount of time until there was flashing in the pump and found it to be acceptable. The inspector determined that since the procedure contained the proper restoration steps, then it was reasonable to assume that given an EFW actuation signal, the operators would have secured from the test and restored the EFW lineup.

The inspector reviewed the Safety Determination associated with the TCN and found that the licensee answered 'No' to question 3, "Does this change have the potential to adversely affect nuclear safety?" The Safety Determination stated that this change only provides a testing window during normal operations or hot shutdown conditions and that there is no change in nuclear safety or safe plant conditions. The licensee stated that the reason they answered 'No' was that none of the individuals involved recognized that closing the recirculating valves could have affected the long-term operability of the pumps. The PRG determined that the TCN was prepared, reviewed and approved in a proper administrative manner and that no change in the procedure review process is warranted.

The inspector disagrees with the PRG that TCN 1-93-0055 was prepared, reviewed and approved in a proper administrative manner. Administrative Procedure 1001A, "Procedure Review and Approval," step 4.2.2 states that when answering the question whether the change has the potential to adversely affect nuclear safety or safe plant operations, broad consideration should be given to the proposed change with respect to its likelihood to affect nuclear safety or safe plant operations. For example, one should consider whether the proposed change is likely to affect the operation of safety-related components or equipment. Since this TCN had the potential to adversely affect nuclear safety and the TCN affected the operation of safety-related components, the inspector determined that the licensee should have answered question 3 of the Safety Determination 'Yes'. In addition, the fact that the reviewers of the TCN did not recognize that closing the recirculating valves could have affected the long-term operability of the pumps brings into question the training of the TCN preparer/reviewer or whether the preparer/reviewer reviewed the TCN in sufficient detail. The Director of Plant Operations at the time reviewed the TCN. If the licensee had answered 'Yes' to question 3, this error may not have occurred because a Safety Evaluation would have been written resulting in a more thorough review by the preparer and the

Responsible Technical Reviewer. In addition, the TCN would have required an Independent Safety Review, which is allowed to be conducted either before or after the implementation of the change.

The inspector discussed this concern with the licensee who agreed that the Safety Determination, question 3, should have been answered 'Yes' and that the preparer and reviewer should have recognized the importance of maintaining the design recirculating flow. As a corrective action, the licensee plans to train all personnel who are involved in the procedure preparation and review process concerning this incident by April 30, 1994.

The inspector concluded that the failure of the licensee to properly prepare and review TCN 1-93-0055 is a violation of Technical Specification 6.8.1. This error is safety significant in that timely manual action would have been required to prevent the loss of EFW if an EFW actuation had occurred. This violation will not be cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section VII.B of the Enforcement Policy, dated January 1, 1994.

4.0 ENGINEERING (37700, 40500, 62001, 93702)

4.1 Pressurizer Spray Valve Leakage

On March 6, 1994, the licensee identified that the pressurizer spray valve had a body-to-bonnet leak of about 0.1 gallon per minute (gpm). On March 7, after the leak had increased to about 3 gpm, the licensee isolated the valve and on March 17, brought the plant to hot shutdown to repair the valve. The licensee reported the RC-V-1 leakage to the NRC via the Emergency Notification System (ENS) on March 8, 1994, as a condition during operation that resulted in the condition of the nuclear power plant, including its principal barriers, being seriously degraded.

4.1.1 Background

On March 5, 1994, the licensee noted that the reactor coolant system (RCS) leak rate had increased. The RCS unidentified leak rate had been averaging about 0.10 gpm but on the evening of March 5, the leak rate increased to approximately 0.20 gpm. On March 6, 1994 the licensee determined by remote visual (camera) observation, a steam leak in the vicinity of the pressurizer. Upon containment entry and visual inspection, the licensee found a body-to-bonnet steam leak on the pressurizer spray valve, RC-V-1. There was a heavy accumulation of boric acid crystals around the valve body, on the insulation, and on the grating below the valve. Plant Engineering reported that the studs and bolts on RC-V-1 were clearly in good shape, and that the integrity of the valve was not threatened. The leak appeared to be either under or through the flexitallic gasket. The licensee's Plant Review Group (PRG) performed an evaluation of the safety implications of the reactor coolant leakage as required by Technical Specification 3.1.6.6. The PRG determined that it was safe to operate with the RC-V-1 leakage, because the leakage was well within the Technical Specification limit of 10 gpm for identified leakage, and was a gasket leak; not a fault in the RCS pressure boundary. If necessary, the leak could be isolated. The inspector observed the leak via the camera, attended the Radiological Controls pre-job briefing for personnel entering the Reactor Building, observed pictures of the valve following the entry, and attended the PRG meeting. The inspector found that the licensee was aggressive in determining the cause of the increased RCS leak rate. The licensee's efforts in maintaining a very low RCS leak rate assisted them in quickly identifying the leak and is considered a strength.

On March 7, the licensee entered containment and attempted to tighten the body-to-bonnet fasteners on the pressurizer spray valve in accordance with instructions provided by Plant Engineering (JO # 085212). The maintenance technician first torqued the nut that was nearest the leak, but the nut did not move. The technician then turned the nut directly opposite the leak about one flat, which resulted in an increase in steam leakage to approximately 3 gpm. It was noted that this leakage remained below the Technical Specification limit of 10 gpm for identified leakage. That evening, the licensee reduced reactor power to about 75% and isolated RC-V-1 by closing RC-V-3 (motor operated from the Control Room) and RC-V-31 (local manual valve). RC-V-1 was then cracked off its seat to reduce the strain on the studs, thereby increasing the probability of nut movement when torqued. The licensee made a Reactor Building entry to try to tighten the joint. When the technician torqued the first nut, the stud/nut fell off. Further inspection showed three other fasteners nearest the leak were also in a degraded condition. The licensee noted that the reason Plant Engineering reported the previous day that the studs and bolts were clearly in good shape was that the steam leak inhibited a close visual examination and the leak area was behind the valve, making viewing difficult. The licensee kept RC-V-1 isolated until the unit could be shut down and repairs could be performed. The inspector determined that the licensee's initial attempt at stopping the body-to-bonnet leak by torquing the fasteners at power with no isolation was unnecessarily hazardous, because any significant increase in leakage would have presented a high risk to personnel and the plant since the valve would have been difficult to isolate.

4.1.2 Operation and Shutdown without the Pressurizer Spray Line

Technical Functions and Plant Operations performed an evaluation and developed guidance for plant operation, plant shutdown and plant cooldown without the pressurizer spray line. For plant operations, the licensee verified that the pressurizer one-inch vent line, which is normally used for RCS degassification, could be used by the operators to reduce plant pressure; directed the operating crews to minimize operations that could cause pressure transients; directed operating crews how to respond to a plant transient; and took measures to prevent pressurizer boron concentration from excessively diverging from reactor coolant system boron concentration. For the plant shutdown and plant cooldown, the licensee revised Operating Procedure 1102-10, "Plant Shutdown," and OP 1102-11, "Plant Cooldown," to provide the operators with additional guidance. The crew that was designated to perform the shutdown trained on the simulator using the revised procedures and practiced postulated scenarios that could occur during plant shutdown. The training included: a reactor trip from 22 percent power with the steam generators on low level limits; the loss of feedwater pump steam supply at 22 percent power; and a low power feedwater pump trip. The crew also performed a plant cooldown on the simulator using the pressurizer vent and feeding-and-bleeding the pressurizer to reduce plant pressure.

The licensee shut down the plant on March 17. Prior to the shut down the crew was briefed on plant conditions and plant management discussed their expectations for conduct of the shutdown. The Vice President and Director, the Director of Operations and Maintenance, and the Operations Director were in the control room at various times during the shutdown. The shutdown proceeded very smoothly, plant equipment functioned as designed, and there were no problems with RCS pressure control.

The inspectors reviewed the licensee's engineering evaluation and operating procedure changes to support power operations, shutdown and cooldown. The inspector observed the simulator training, the actual shutdown, and the preparations for valve repair. In addition, the NRC Technical Training Center performed transients on the NRC B&W simulator with the pressurizer spray line isolated to confirm the licensee's evaluations. The inspectors determined that the planning for the shutdown, including procedure revisions, simulator training and briefings, and the plant transition to hot shutdown were effectively performed and judged as a strength. The inspectors found that there was extensive management involvement in the entire process, which is also considered a strength.

4.1.3 RC-V-1 Repair

The inspector questioned the licensee about their plans to repair RC-V-1 with the plant in hot shutdown with only single valve isolation. For personnel safety reasons, the licensee's procedures recommend that with a system temperature of greater than 200°F, there should be two valve isolation. The licensee evaluated the single valve isolation and found it was acceptable as long as compensatory measures were taken. These measures included: taking temperature measurements of the isolated piping to ensure that the boundary valves were leak tight; manually closing the motor operated boundary valve, RC-V-3; and verifying the structural integrity of the boundary valves. The inspector determined that the licensee's compensatory measures were adequate.

After verifying there was no boundary valve leakage, the licensee disassembled RC-V-1. During removal of the body-to-bonnet fasteners, two additional studs (total of 3) out of the eight studs broke off due to the corrosion of the studs. The licensee inspected the body-to-bonnet mating surfaces and found no indication of steam cutting or other degradation. The licensee replaced all the carbon steel fasteners with the same type of fastener and replaced the body-to-bonnet flexitallic gasket.

The inspector reviewed Job Order # 085210, "RC-V-01 Body-Bonnet Leak" prior to commencement of the work and Velan Engineering drawing P2-0590-N4/41, Revision F. The inspector found that the RC-V-1 maintenance repair was appropriately conducted and had no further questions in this area.

4.1.4 Pressurizer Spray Line Restoration

The licensee prepared Special Temporary Procedure, "RC-V-1 Return to Service," and a safety evaluation to unisolate the spray valve following the repair. The inspector attended associated licensee meetings and reviewed the procedure, and found that the licensee had fully evaluated the thermal shock and water hammer concerns associated with the evolution. The inspector noted the strong involvement of the licensee operations staff and the thoroughness of the procedure development and safety review.

The inspector locally observed operations personnel returning the spray line to service and found that the evolution was performed in a cautious, controlled manner. The licensee warmed the spray valve piping by throttling the spray valve by-pass valve, RC-V-24, and opening the isolation valves. The licensee performed a post-maintenance leak check and found no leakage. The inspector determined that overall, the preplanning and the conduct of spray line restoration was good.

4.1.5 Licensee Inspection of Similar Components

After discovery of the degraded condition of RC-V-1, the licensee performed additional component inspections to determine if any other conditions existed which could reduce the integrity of the RCS boundary. Plant Engineering reviewed Inservice Inspection (ISI) drawings to determine the location of all bolted body-to-bonnet connections in Class 1, high pressure, borated systems. The licensee utilized inspection teams consisting of engineering and operations staff to perform VT-2 inspections of these bolted connections, as well as other accessible components, prior to startup. The licensee's objective was to remove and inspect fasteners on any component where there was evidence of RCS leakage (boric acid crystals).

The inspection team identified one additional valve, MU-V-113, which exhibited signs of potential boric acid corrosion so the licensee replaced five out of the eight carbon steel fasteners. The inspector observed that two of the five bonnet studs had started to form the hour-glass corrosion shape.

The inspector interviewed licensee staff, reviewed applicable drawings, and performed several walkdowns of borated systems inside containment. The inspector found no evidence of additional body-to-bonnet leakage or corrosion on bolted connections. The inspector determined that the depth and scope of the licensee inspection effort was satisfactory.

4.1.6 Root Cause Analysis (URI 50-289/94-04-01)

The pressurizer spray valve, RC-V-1, is an insulated Velan 2-1/2" bolted bonnet globe valve. The body and bonnet are both made of 316 stainless steel; the eight-5/8" diameter bonnet studs were made of Grade B7 carbon steel; and the eight bonnet nuts were made of 2H carbon steel. A visual examination of the eight removed spray valve fasteners revealed that: three of the fasteners were still in good condition; the three fasteners that had broken off were eroded to an hour-glass configuration; one fastener, although not broken during removal efforts, was eroded to an hour-glass configuration to approximately 1/4" diameter; and one fastener was eroded to approximately minimum thread diameter of the stud.

The inspector conducted interviews and reviewed maintenance records to determine the maintenance history of RC-V-1. The last time the spray valve body-to-bonnet joint was worked was October 13, 1983 (Task Number CA192, Inspection Procedure SP1101-12-051, "Swiping for Sulphur Samples"). There was no recent maintenance work that would have contributed to joint failure. The valve had a history of numerous packing leaks. Most recently, the licensee repacked the valve on September 27, 1993 during the 10R Refueling Outage (JO #052738) and again on November 16, 1993 (JO #080478) during the 10U1 Outage (outage to repair the pressurizer code safety valve). During the 10U1 Outage, Plant Operations observed bubbling from the body-to-bonnet joint on RC-V-1 and a maintenance planner generated a Work Request to repair this leak. However, Plant Maintenance personnel later inspected the valve, and based on the accumulation of boron on the valve operator, determined that there was a packing leak, instead of a body-to-bonnet leak. Accordingly, Plant Maintenance canceled the Work Request to repair the body-to bonnet joint without discussing this with the Operation Engineer who identified the leakage. Plant Maintenance stated that a cursory visual inspection of half of the body-to-bonnet fasteners had been done, but was not documented.

Initial evaluations by the inspector and the licensee determined that the cause of the degraded condition of the RC-V-1 fasteners and subsequent body-to-bonnet leakage was boric acid corrosion. In addition, the body-to-bonnet leakage was not a result of gasket failure but the result of fastener elongation and/or failure. The valve body insulation may have been a contributing factor in allowing the accumulation of boric acid crystals near the body-to bonnet joint. The licensee has initiated a Plant Experience Report (PER) to assess the root cause of the RC-V-1 body-to-bonnet leak. The PER will include the results of a laboratory evaluation of the failed fasteners and the licensee's evaluation of the events surrounding the cancellation of the November 1993 Work Request. Therefore, this issue will be considered unresolved pending completion of the licensee's PER and further NRC review. **(URI 50-289/94-04-01)**

4.1.7 Conclusions

In summary, the inspectors observed licensee activities associated with the pressurizer spray valve leakage, including: the initial identification of the leak; the simulator training and conduct of the shutdown without the pressurizer spray line available; the as found condition and repair of the valve; the restoration of the pressurizer spray line; the licensee's inspection of additional components which could have a similar problem; and the root cause analysis. The inspectors found that the licensee maintains a very low RCS leak rate, which enabled them to identify the RC-V-1 leakage very early. The licensee's planning and conduct of the shutdown were effectively performed, with extensive management involvement. In addition, the licensee's efforts in returning the spray line to service were good and the scope and depth of their inspections to determine if any other conditions existed which could reduce the integrity of the reactor coolant system boundary was satisfactory. However, the licensee's initial attempt at stopping the body-to-bonnet leak by torquing the fasteners at power with no isolation was unnecessarily hazardous, because any significant increase in leakage would have presented a high risk to personnel and the plant since the valve would have been difficult to isolate.

Additional inspection will be performed to further assess the root cause of the leakage. Corrosion caused by leaking reactor coolant containing dissolved boric acid has been recognized for some time. The NRC has issued five information notices (80-27; 82-06; 86-108; and 86-08, Supplements 1 and 2), a bulletin (82-02) and a Generic Letter 88-05. Generic Letter 88-05 includes information on what a licensee program should include to provide assurance that the reactor coolant pressure boundary will have an extremely low probability of abnormal leakage, rapid propagating failure, or gross rupture as a result of boric acid corrosion. The generic letter also states that the licensee "shall maintain, in auditable form, records of the program and results obtained from implementation of the program." As part of the NRC inspection follow-up of the root cause of the spray valve leakage, the licensee's boric acid corrosion program will be evaluated.

4.2 Control Rod Drop Time Testing

On March 17, 1994, the licensee performed control rod drop testing in accordance with Surveillance Procedure 1303-11.1, "Control Rod Drop Time." There were seven control rod groups to be tested, and each control rod group contains eight rods. 12 rods initially failed to meet Technical Specification 4.7.1.1 rod drop (flight) time of 1.66 seconds from the time the rod mechanism was deenergized to the time that the rod reached the 25% withdrawn level. The rods that initially failed the criterion were 1-1 (group 1, rod 1), 1-2, 1-3, 3-3, 3-4, 3-5, 3-6, 4-5, 5-4, 5-7, 5-9, and 6-5. The actual drop times were in the range of 2.06 to 2.88 seconds. The licensee reported this condition to the NRC via the Emergency Notification System (ENS) on March 17. The licensee had previously experienced excessive drop times for rods 1-3, 3-6, and 4-5 (actual drop times were in the range of 1.72 to 1.83 seconds) during testing conducted at the end of the 10R refueling outage in October 1993. The licensee performed the control rod drop time testing on March 17, as a follow up to the October 1993 incident.

As in October, the licensee believed that they were experiencing a problem similar to that first experienced by one of the Oconee plants in 1991. At Oconee, the out-of-specification rod was able to eventually pass the drop time criterion by dropping the rod a number of times to free the four ball check valves in the thermal barrier portion of the control rod drive mechanism (CRDM). At TMI, the licensee suspected that corrosion or corrosion products may have been preventing some or several of these ball check valves from fully opening, thereby extending the rod drop time. During the period March 17 to March 20, the licensee continued to drop the affected control rods, until the drop times were consistently below 1.66 seconds. As of March 20, 11 of the 12 rods with excessive drop times, had drop times within the 1.66 second criterion. However, Rod 1-3, which had been dropped 46 times, still exceeded the specification with a drop time of 1.81 seconds.

On March 18, 1994, a teleconference was held between the licensee, NRC Region I and the NRC Office of Nuclear Reactor Regulation (NRR). During this discussion, the licensee stated that they would not startup the plant without first informing the NRC of their basis for restart, including their evaluation of the root cause of the excessive drop times. The licensee worked with Babcox and Wilcox (B&W) to further evaluate the root cause of the excessive drop times. Because the range of drop times had increased from 1.72 to 1.83 seconds, to 2.06 to 2.88 seconds, the explanation for the Oconee problem did not fully explain the problem being experienced at TMI-1. B&W had previously evaluated the effect on the drop time of all four ball check valves being closed and determined the predicted drop time to be 2.14 seconds. Eleven of the problem rods had drop times greater than 2.14 seconds. Based on further evaluation, the licensee and B&W concluded that the excessive times were due to crud buildup in the four ball check valves and in the gap between the lead screw and the thermal barrier bushing. The licensee believed that the crud buildup was related to primary water chemistry control. Due to extended cycles, initial boron concentration at TMI-1 had been higher for Cycle 9 and 10. With a fixed upper limit of 2.2 ppm lithium, the pH at the beginning of Cycle 9 and 10 was lower than 6.9. A pH of 6.9 or greater results in less production of corrosion products. The licensee and B&W also evaluated the limiting FSAR events to justify an increased rod drop test time of 3.0 seconds. This increased rod drop time was applied to all rods, not just the 12 known slow-dropping rods.

The inspectors observed initial and subsequent control rod drop testing, and reviewed the test data. In addition, the inspectors reviewed the licensee's root cause analysis and the evaluation to justify the 3.0 second drop time. On March 22, 1994, the licensee submitted an exigent Technical Specification Change Request (TSCR) to the NRC to increase the Control Rod Trip Insertion Time Testing acceptance criterion to 3.0 seconds for control rod drop time for the remainder of Cycle 10. In order to allow the TMI-1 startup to proceed within the current Technical Specification requirements, considering the restrictions for an inoperable control rod, the licensee additionally requested that a Notice of Enforcement Discretion be issued allowing startup until the TSCR was approved. In addition, the licensee stated that they would perform additional actions to support startup including: increase lithium concentration in the RCS to raise pH to reduce the rate of corrosion; increase the amount of CRDM exercise done to reduce the likelihood of crud buildup in the gap between the lead screw and the thermal barrier bushing; and initiate a special test program to verify CRDM drop times. Initially, the drop time would be obtained within three months of reactor startup. Subsequent testing intervals would be based on the results. Also, during startup when plant power is between 0% and 25% full power, the high flux trip setpoint would be set at less than or equal to 50% to assure the FSAR acceptance criteria for the startup accident are met.

The licensee discussed their March 22, 1994 submittal with NRC Region I and NRR on March 23. As a result of this discussion, it was determined that a meeting was required to further discuss the licensee's submittal. On March 23, the licensee performed additional rod drop exercising and all rods met the acceptance criterion of 1.66 seconds. Therefore, the licensee no longer needed Enforcement Discretion to allow startup prior to the TSCR being approved. On March 25, 1994, a meeting was held in Rockville, Maryland between the licensee and representatives of B&W, and representatives of NRC Region I and NRR. Based on the licensee's root cause analysis, the NRC staff agreed that sticking ball check valves were likely contributing to the excessive rod drop times. However, the licensee had not conclusively determined that the additional rod drop time could be contributed to the crud buildup in the bushing area and that corrections to water chemistry would necessarily eliminate or reduce the problem. Therefore, the NRC staff concluded that it was acceptable for the licensee to restart the plant only with their commitment to perform several additional short and long term actions. These included the licensee's original commitments to increase lithium concentration in the RCS, to increase the amount of CRDM exercise done periodically, and to obtain control rod drop times within 3 months of reactor startup. In addition, the licensee committed: to submit to the NRC their evaluation criteria and a contingency plan to be utilized for the additional control rod drop time testing; to obtain NRC approval prior to conducting additional rod exercising if any control rods exceed the 1.66 second drop time criterion; and if NRC approval is not obtained to exercise these rods, or if the rods cannot be exercised to within the 1.66 second drop time criterion, at least one control rod drive mechanism will be removed and inspected. The licensee committed to complete these actions in a letter dated March 26, 1994. The NRC confirmed its understanding of the actions the licensee had taken or planned to take as the result of rod drop testing on March 17, 1994 in Confirmatory Action Letter (CAL) 1-94-004, dated March 29, 1994. The licensee withdrew their request for an exigent TSCR regarding control rod drop time test criteria, as all rods were within existing Technical Specification requirements.

The inspectors concluded that the licensee's testing of the control rods at this shutdown was a positive initiative, since there was no regulatory requirement to do so, and it enabled the licensee to identify this degraded condition early. The inspector determined that the licensee could have been more conservative by choosing to disassemble and inspect one of the control rods to determine the root cause of the increased drop times. The licensee's evaluation to support an increase in the allowable rod insertion time for all rods combined with a probable root cause, did allow us to determine that minimal risk to public health and safety existed. The licensee's commitment to resolve the issue is contained in Confirmatory Action Letter 1-94-004 dated March 29, 1994.

4.3 Emergency Diesel Generator End Bearing Alignment

The inspector performed a follow-up inspection of the licensee's corrective actions regarding an advanced or abnormal wear rate on the emergency diesel generator (EDG) end bearings. The generator end bearing is a 14 inch double tapered roller bearing and is self-lubricated by a one liter lubricating oil supply. As discussed in Inspection Report 50-289/92-18, when the licensee performed the annual oil change in December 1991, they found that the oil on the 'A' EDG was black and had a wear particle concentration that showed the bearing was experiencing an advanced wear rate. The licensee increased the oil sample frequency from annually to quarterly and found the sample results for the next nine months showed an advanced or abnormal rate of wear even after short run durations. In September 1992, the inspector found that the licensee was considering decreasing the oil change frequency to annually before understanding the cause or extent of the bearing wear. Subsequently, the licensee determined that the hand-held vibration detector, which measures total vibration, could not detect early stages of a roller bearing defect. Spectral vibration data is required to fully evaluate the bearing status. The licensee connected test equipment to measure spectral vibration data and found vibration was elevated at 123 hertz. This indicates a defect in the early stages on the outer race of the roller bearing.

Since September of 1992, the licensee has taken more data to analyze the current condition of end bearings on both EDGs. The wear particle concentration, which was originally over 500, has remained relatively steady at 100 for both EDGs. Although bearing temperature is not a good indication of early wear, the licensee plotted the bearing temperatures during a four hour run. The trends for both bearings were almost identical and the temperatures were within an acceptable range.

The licensee also recorded bearing vibration data for both EDGs and sent it to Technical Associates, a bearing vibration analysis consulting firm. The analysis showed that for the 'A' EDG, the vibration amplitudes at the defect frequencies tended to die out after four hours of EDG operation. This decrease is likely due to the EDG reaching thermal equilibrium. The generators are initially aligned cold and are set to account for growth as the EDG warms. Since the EDGs are designed to operate continuously, the licensee determined that the vibration in the 'A' EDG was acceptable.

For the 'B' EDG, the licensee found that the vibration amplitudes at the defect frequencies did not tend to die out as the diesel reached thermal equilibrium. The licensee determined that the reason the vibrations did not decrease in the 'B' EDG is one or more of the following: 1) a bearing defect, 2) a bearing axial misalignment, or 3) a bearing radial misalignment. To check for a bearing defect, the licensee performed a visual inspection of the bearing and determined that there is no apparent spalling of the outer race. However, the bearing was not disassembled during the inspection and, therefore, the inspection was very limited. Without disassembly, the inner and outer bearing races cannot be inspected well and one of the two sets of rollers on this double tapered roller bearing cannot be observed. The visual inspection of the bearing described in the diesel vendor manual requires bearing disassembly. This vendor guidance is not intended to be performed on a periodic basis.

To check for an axial bearing misalignment on the 'B' EDG, the licensee measured the axial clearances and found 40 mils of clearance on the inboard direction and 90 mils of clearance on the outboard direction, which are within manufacturer's specification. The licensee lightly tapped the outer race and moved it inward 5 mils. This demonstrated that the outer race was free to move when not under dynamic loading.

The licensee has not taken radial bearing position measurements on the 'B' EDG. However, there are three indications that show that there may be a radial misalignment problem: 1) As described above, the defect frequencies for the bearing do not die off when the EDG reaches thermal equilibrium; 2) During the visual inspection, rollers at the bottom were loaded with the weight of the shaft. For the remaining rollers, there was a clearance between the rollers and both races and the rollers could turn freely, and; 3) There is a clicking noise from the bearing that can be heard during diesel operation that is likely being caused by the rollers leaving a heavily loaded area of the race and moving to a lightly loaded area. The inspector questioned the licensee why they had not taken radial bearing position measurements. The licensee stated that they have not found a practical means to perform the measurements.

The licensee then had Controlled Vibrations take additional vibration measurements using a high frequency envelope detection technique. Controlled Vibrations determined bearing failure is not an immediate concern because when bearings begin to fail they typically produce nonsynchronous energy levels of greater than 50% and the 'A' and 'B' EDGs had levels of less than 25% and 10% respectively. Based on the results, the licensee concluded that there were no immediate concerns with the bearing, but a trending program should be developed to track the status of the bearing over time for comparison with previous readings. The licensee is in the process of developing this trending program. The licensee also plans to reduce the frequency of oil changes from quarterly to semiannually.

The inspector determined that it is a good initiative to implement a long term bearing vibration trending program. However, for the 'B' EDG there are several indications that there may be a radial misalignment between the diesel and the generator. The licensee has no long term vibration data to show that this bearing is not experiencing degradation as a result of this potential misalignment. A vibration trending program is not a sufficient substitute for determining that the radial bearing position measurements on the 'B' EDG are within the manufacturer's tolerance. The inspector discussed this with the licensee and they agreed to take radial bearing position measurements and make adjustments if necessary on both EDGs during the next diesel overhaul in May. The inspector concluded that the licensee should have been more aggressive in evaluating the potential radial bearing misalignment.

4.4 Reactor Coolant System Thermowell Design

While evaluating a modification to the reactor coolant system (RCS) thermowells, the licensee found that the thermowell design that is currently installed exceeds the allowable shear stress of ASME B31.7 and ASME Code Section III. The licensee made a Emergency Notification System notification in accordance with 10 CFR 50.72(b)(1)(ii)(B), as a condition during operation that results in the power plant being outside the design basis of the plant. The licensee calculated the shear stress to be 14,180 psi at an RCS pressure of 2750 psi (maximum accident pressure) and the ASME allowable shear stress is 10,410 psi. The design also exceeds the allowable sheer stress at 2155 psi (normal operating pressure), which will result in the plastic flow of the thermowell material. The licensee determined that the thermowells are still operable because the ultimate shear stress for this material is 34,216 psi based on ASME Section III Appendix I, and therefore a breach or failure of the material is not expected. The NRC has reviewed GPUN's calculations and agrees that plastic flow will occur, which may result in thermowell leakage, but the material is not expected to fail and therefore the licensee's operability determination is acceptable. However, the NRC determined that having components with sheer stresses that exceed the allowable limits is not conservative. The NRC is currently preparing an Information Notice that will provide generic guidance to licensees regarding this issue.

5.0 PLANT SUPPORT (71707)

5.1 Radiological Controls

The inspectors examined work in progress to verify proper implementation of health physics (HP) procedures and controls. The inspectors monitored ALARA implementation, dosimetry and badging, protective clothing use, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials. In addition, the inspectors observed personnel working in RWP areas and verified compliance with RWP requirements. During routine tours, the inspectors verified a sampling of high radiation area doors to be locked as required.

The inspectors attended radiological controls pre-job briefings for activities associated with the pressurizer spray valve leakage identification and repair. The inspector found that the briefings were very thorough and overall radiological control practices were properly implemented.

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, the inspectors observed protected area access control and badging procedures. In addition, the inspectors routinely inspected protected and vital area barriers, compensatory measures, and escort procedures.

The inspectors concluded that the Security Plan was being properly implemented.

6.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (30702)

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and areas of concern to the inspectors. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting with licensee management 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.