U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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Licensee: Northeast Nuclear Energy Company
P. O. Box 270
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Facility: Millstone Nuclear Power Station, Units 1, 2, and 3

Inspection at: Waterford, CT

Dates: February 23, 1994 - April 5, 1994

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Reactor Projects Section No. 4A

Scope: NRC resident inspection of core activities in the areas of plant operations, radiological controls, maintenance, surveillance, security, outage activities, licensee self-assessment, and periodic reports.

The inspectors reviewed plant operations during periods of backshifts (evening shifts) and deep backshifts (weekends, holidays, and midnight shifts). Coverage was provided for 111 hours during evening backshifts and 15 hours during deep backshifts.

Results: See Executive Summary

EXECUTIVE SUMMARY

Millstone Nuclear Power Station

Combined Inspection 245/94-14; 336/94-11; 423/94-11

EXECUTIVE SUMMARY

Plant Operations

Unit 1 remained shutdown throughout this reporting period for the cycle 14 refueling outage. Plant startup has been delayed more than two weeks due to emergent work, inaccurate original estimates of work scopes, and delays in testing of motor-operated valves and service water repairs. Plant startup is currently scheduled for late April.

Unit 2 operated at essentially full power for most of the report period. On February 28, one of the four seals in the 'D' reactor coolant pump (RCP) failed. Operators promptly identified the degraded seal, and coordinated well with engineering and maintenance staffs to trend seal parameters for further degradation. The inspector identified that the licensee did not recognize that anytime the high pressure safety injection (HPSI) system throttle valves are not in their analyzed position, the affected HPSI train would not perform its intended safety function. The licensee issued guidance to ensure the appropriate technical specification action statement is entered anytime the HPSI throttle valves are not in their required positions.

Unit 3 operated at full power for most of the report period. On March 23, reactor power reached 101% due to inadvertent dilution of the boron concentration in the reactor coolant system (RCS). No reactor protective functions were actuated or required. The transient was caused by inadequate operator performance of a boric acid pump operational readiness test.

Maintenance

Several maintenance and testing activities at each unit were observed to be well-performed. At Unit 1, the refurbishment of safety-related solenoid valves for the emergency diesel generator (EDG) without approved procedures and with inadequately dedicated commercial grade parts resulted in two violations. This activity also revealed an unresolved concern with quality assurance program coverage of maintenance. Two Unit 1 reactor safety relief valves (SRVs) failed to lift during required testing. The four remaining SRVs lifted at setpoints above the allowed tolerance. The licensee replaced all six SRVs with refurbished or modified valves. The effect of the as-found test condition, as well as, the adequacy of corrective action remained unresolved.

The inspector identified that current testing of the Unit 2 enclosure building filtration system did not adequately demonstrate operability of the system heaters. The licensee successfully conducted a new test to verify heater operation. Evaluation of other system design deficiencies remained unresolved at the end of the inspection.

Engineering

Unit 1 engineering identified that the emergency service water system overpressure which prevents the release of radioactive contamination from a leak in the low pressure coolant injection heat exchanger may not be sustained under all design conditions. At the end of the inspection, the licensee had not decided on which of several methods to resolve this deficiency. Unit 1 also found and corrected a discrepancy between the technical specification and accident analysis values for reactor vessel level setpoints.

Unit 2 engineering identified a nonconformance in the electrical isolation scheme between the safety-related reactor coolant system cold leg temperature loop and the non safety-related feedwater regulating system control loop. The nonconformance was due to the incorrect implementation of a 1983 plant design change. License evaluation concluded that there was no failure modes which could prevent the actuation of the protection instruments housed in the applicable class 1E cabinet and therefore the devices contained in the cabinets remained operable.

The porous concrete which underlays the Unit 3 containment basemat has been observed to be eroding/leaching since 1987. To date less than one percent of the total cement content has been collected. The licensee is evaluating the condition and has performed mock-up tests to determine that the cement has retained sufficient strength as a load bearing media; thus justifying continued safe operation of the plant in its present condition. The long term significance of the erosion/leaching and corrective actions will be established upon completion of the testing program which is due in June 1994.

An engineering review of an in-house safety system functional inspection identified that the Unit 3 'A' auxiliary feedwater supply line was potentially inadequately designed for high energy line breaks (HELBs). Generally good corrective actions were implemented to preclude unanalyzed operation of the system while a structural evaluation is performed to determine the adequacy of the design for HELB concerns.

Plant Support

The Unit 1 staff responded well to the injury of a worker and his transport to the hospital in contaminated clothing. Unit 3 efforts to reduce exposure for routine containment entries were effective.

TABLE OF CONTENTS

The inspection procedures (IP) from NRC Manual Chapter 2515, Light Water Reactor Inspection Program, that were used as guidance are listed parenthetically for each report section.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 remained in cold shutdown during the report period. Fuel reload and the plant integrated leak rate test were successfully completed. The scheduled startup date slipped from late March to mid-April due to inaccurate time estimates for completion of some scheduled activities, refueling bridge and condenser tube replacement equipment failures, and an increase in the outage work scope. Some of the schedule slippage in the work control area was predetermined by a conservative approach utilized by the licensee to minimize risk to the fuel elements while shutdown. For example, the main steam isolation valves were not repaired while the refueling cavity was flooded even though plugs had been installed in the main steam lines. However, other delays could have been avoided if deficient procedures/equipment had been corrected as a result of previous refueling outages. For example, valuable critical path time was lost while licensee personnel investigated why the reactor vessel studs could not be stretched to the required length using the hydraulic force that was specified in the head torquing procedure. Subsequent investigation by the licensee revealed that, in previous refueling outages, personnel had utilized a higher pressure than what was specified in the procedure to obtain the required bolt stretch. This fact was not relayed to licensee management during those outages and the procedure was never changed.

Unit 2 operated at full power for most of the report period. Short power reductions were effectively performed for scheduled maintenance and testing. On April 7, the licensee reduced power to 96% due to a loss of the normal power supply to the primary plant computer. Full power operations resumed on April 8 following repairs to the normal power supply inverter. On April 16, the licensee reduced power by 5 megawatts thermal (0.002%) to minimize the effects of minor power fluctuations due to perturbations of the #3 main turbine control valve. The control valve has a faulty circuit card which will be replaced during a planned outage scheduled for late April 1994.

Unit 3 entered the report period at 100 percent of rated thermal power. The unit remained at full power throughout the inspection period with the exception of minor power reductions while performing monthly turbine control valve testing. The licensee identified a three gallon-per-day leak past two check valves for the 'C' safety injection (SI) accumulator. The licensee developed an action plan to reduce the likelihood of diluting the boron concentration of the 'C' SI accumulator.

2.0 PLANT OPERATIONS (IP 71707, 71710, 93702)

2.1 Operational Safety Verification (All Units)

The inspectors performed selective inspections of control room activities, the operability of engineered safety features systems, plant equipment conditions, and problem identification systems. These reviews included attendance at periodic plant meetings and plant tours.

The inspectors made frequent tours of the control room to verify sufficient staffing, operator procedural adherence, operator cognizance of equipment and control room alarm status, conformance with technical specifications, and maintenance of control room logs. The inspectors also observed control room operators response to alarms and off-normal conditions.

The inspectors verified safety system operability through independent reviews of: system configuration, outstanding trouble reports and incident reports, and surveillance test results. During system walkdowns, the inspectors made note of equipment condition, tagging, and the existence of installed jumpers, bypasses, and lifted leads.

The inspectors determined these operational activities were adequately implemented. Specific observations are discussed in Section 2.2 to 2.7 below.

2.2 Pressure Isolation Valve Leak Tightness Review - Unit 1

The inspector reviewed the ability of operators to detect leakage from high to low pressure systems at Unit 1. Unit 1 has two low pressure systems, the low pressure coolant injection (LPCI) and the core spray (CS) systems, that directly interface with the higher pressure reactor coolant system. Both systems are isolated from the reactor coolant system by a combination of check valves and normally closed motor-operated isolation valves. If the isolation valves leak by, relief valves in the LPCI and CS systems will actuate at approximately 400 pounds per square inch (psi) to prevent system overpressurization. Indication of leakage from the high pressure to the low pressure system is provided by pressure switches, which will alarm in the control room if the pressure in the LPCI or CS systems reaches a preset limit.

The motor-operated pressure isolation valves for the LPCI and CS systems, LP-10A(B), and CS-5A(B) are local leak rate tested (LLRT) once per refuel outage. All four valves successfully passed their LLRT during the current refuel outage. The leak tightness of the upstream check valves which serve as pressure isolation valves LP-11A(B) and CS-6A(B) is also verified once per refuel cycle by performance of a seat tightness test. The setpoints of the alarm pressure switches are verified every refuel outage, and the setpoints of the system relief valves are verified every other refuel cycle. No evidence of pressure isolation valve leakage has been noted since 1989.

The inspector reviewed the control room alarm response procedures for the pressure isolation switches. Upon receipt of a system high pressure annunciator in the control room, the alarm response procedure directs operators to determine if the relief valve for the respective system has lifted by monitoring the reactor building sump level. Operators are instructed to reduce the leakage into the system by closing additional isolation valves. The alarm response procedures contain a note, that informs operators that receipt of a high pressure alarm indicates that the potential exists for an interfacing system loss of coolant accident.

Based upon a review of the system design, maintenance and operating procedures, the inspector concluded that the licensee has implemented adequate measures to ensure pressure isolation valve leakage into low pressure systems is minimized. If leakage does occur, procedures provide adequate guidance to operators on what action should be taken to investigate and reduce the amount of pressure isolation valve leakage. The inspector had no further questions.

2.3 'D' Reactor Coolant Pump Lower Seal Failure - Unit 2

On February 28, 1994, during the performance of weekly service water (SW) differential pressure (dp) measurements, the spare reactor building component cooling water (RBCCW) heat exchangers were sequentially placed in service. This process resulted in increased RBCCW temperatures across the 'D' reactor coolant pump (RCP) seal cooler. Increased seal injection temperature causes fluctuations of seal dp. At approximately 4:00 a.m. on February 28, the lower and middle RCP seal pressures became erratic, and mid-seal pressure rose to over 1800 psig causing a "mid-seal pressure high" annunciator alarm. The dp across the lower seal dropped from approximately 750 psid to approximately 520 psid. The licensee determined the 'D' RCP seal was degraded, and initiated plant information report PIR 2-94-084 to investigate the causes. After further evaluation, the licensee determined that the 'D' RCP lower seal had failed, and began trending RCP seal dp's to identify further degradation of any of the seals.

The RCP seal package manufactured by Byron Jackson is a four stage sealing device (lower, middle and upper seals, and a vapor seal). The seals prevent water from the reactor coolant system (RCS) from escaping around the RCP shaft to containment, causing an unisolable loss of coolant accident (LOCA). All 4 seals are capable of withstanding full pressure.
The first three seals reduce pressure from normal RCS pressure (approximately 2260 psig) to less than 100 psig in equal increments. The vapor seal reduces pressure to atmospheric. Licensee guidance considers seal failure to occur when the dp across a seal drops to less than 500 psid. RCP operation may continue with one failed seal, provided the remaining seals do not show signs of degradation. The vendor considers each seal operable until 300 psid.

The inspector evaluated the licensee's actions following the initial identification of seal degradation. The licensee's initial response to the 'D' RCP seal degradation was good. Operations personnel identified the lower seal dp perturbations early, conservatively declared that the seal had failed, and carefully monitored seal parameters. Good cooperation existed between Operations, Maintenance and Engineering Department staffs in monitoring and trending seal parameters for degradation. One exception was a two week delay for the engineering organization to issue a setpoint change for the midseal pressure high alarm, which would provide operators with a visible/audible warning of further seal degradation. The inspector addressed this issue with engineering management. The engineering organization had been uncertain how to perform the setpoint change, due to conflicting guidance found in corporate and site administrative procedures for bypass jumpers. The licensee is reconciling the procedures, and reviewing the administrative procedure verification process to identify how conflicting procedures were issued. The licensee plans to change out the 'D' RCP seal during a planned outage in April 1994. The inspector had no further questions.

2.4 High Pressure Safety Injection Inoperability During Testing - Unit 2

On March 4, the inspector identified a condition where a train of high pressure safety injection (HPSI) is routinely rendered inoperable by shutting its respective injection throttle valves, and the licensee did not consider the train to be inoperable, nor track the outage time allowed by Technical Specification Action Statement (TSAS) 3.5.2.a, "Emergency Core Cooling Systems," when one train of HPSI is inoperable. If high pressure safety injection (HPSI) throttle valves (2-SI-617, 627, 637, and 647 for train A, or 2-SI-615, 625, 635, and 645 for train B) are shut, injection flow from the respective train of HPSI is prevented. The operator considered the HPSI system operable because those valves open automatically on a safety injection actuation signal (SIAS). Although the throttle valves open automatically, the inspector noted that they are all set to open shy of their established throttled positions, and must be manually opened the rest of the way. The final throttled positions ensure meeting the minimum HPSI flow requirements in the licensee's accident safety analysis and technical specifications.

The inspector questioned the operations and engineering staff regarding the operability of a HPSI train when the throttle valves are closed, noting that under current guidelines, operators did not consider the HPSI train inoperable during those times. The inspector was concerned that the licensee's apparent lack of understanding of this issue could result in: exceeding the TS allowed outage time for an inoperable train of HPSI; failure to implement compensatory actions required by TSAS 3.5.2.a if the allowed outage time is exceeded; and/or rendering both trains of HPSI inoperable while this condition existed. The inspector discussed his concerns with the Unit Director, prompting an evaluation by the licensee's engineering organization. The inspector also reviewed 1993 records of periodic surveillance procedures which shut the HPSI throttle valves, and noted that the allowed outage times for TSAS 3.5.2.a had not been exceeded.

On March 14, the licensee's engineering department issued a memorandum to operations which stated that each of the HPSI throttle valves must be at their required position to consider the respective train operable. The Operations Manager subsequently issued a night order directing that TSAS 3.5.2.a should be entered anytime the HPSI injection throttle valves are not in their required position. The licensee is also creating a procedure which identifies every surveillance which prevents a safety system from performing its intended safety function. Additionally, each procedure will include guidance to enter the appropriate TSAS. The inspector considered the licensee's corrective actions to be adequate; however, the failure to critically assess how the HPSI system was affected by shutting the injection throttle valves reflects poorly on the safety perspective of the operations and engineering department staffs. The more generic concern over licensee control of equipment operability during surveillance testing is discussed further in section 6.3.4 of this report.

2.5 Reactor Coolant Leakage - Unit 3

Since the completion of the cycle four refueling outage in November 1993, the licensee has identified slight leakage past the 'C' safety injection (SI) accumulator check valves. This condition was identified by the reactor engineering supervisor during a work observation when the accumulator high level alarm annunciated in the control room. Licensee investigation into the event identified that reactor coolant was leaking past the two SI accumulator check valves at approximately three gallons per day. This leakage is within technical specification (TS) 3.4.6 allowed limit of five gallons per minute leakage through reactor coolant system (RCS) pressure isolation valves. There is no other known leakage past RCS pressure isolation valves.

In response to this condition, the licensee developed an action plan to monitor and reduce the likelihood of dilution of the 'C' SI accumulator boron concentration outside the TS tolerance, and to minimize the demand (frequent draining and filling) on plant operators. The action plan requires that the accumulator be drained and refilled from the refueling water storage tank to offset any dilution. In addition, plant operators log accumulator level shiftly and the chemistry department samples the accumulator whenever the level increases by one percent to determine the changes in the leakage rate and the affect on accumulator boron concentration. System engineering has calculated the time to dilute accumulator boron concentration out of TS limits without operator intervention and is reviewing industry experience, with respect to RCS leakage into accumulators, to address whether the leakage is expected to increase. System engineering has been tasked with identifying the maximum leakage rate at which the plant should consider shutting down the plant to repair the leaking check valves. Work orders have been developed to add accumulator check valve leakage checks into the unexpected shutdown work list. The previous leak check of the 'C' SI accumulator check valves conducted in October 1993 identified zero leakage.

The inspector reviewed the action plan and chemistry results, and verified that operators and the system engineer are monitoring accumulator tank level shiftly and sampling the accumulators as required by TS. The inspector noted that the leakage rate appears to be stable and that accumulator boron concentration hasn't been significantly affected by the monthly filling and draining evolutions. The inspector considered the licensee's action plan to address the leakage to be good. The inspector had no further questions at this time.

2.6 Reactor Power Increase due to Unplanned Boron Dilution - Unit 3

On March 23, 1994, with the plant at 100 percent power, a reactor power increase occurred which resulted from a three minute boron dilution of the reactor coolant system (RCS). During a blended makeup, the boric acid transfer pump was realigned for recirculation to the boric acid tank (BAT) and the primary makeup water continued to flow into the RCS. Reactor power was immediately reduced and the plant stabilized at 100 percent. The licensee's review of the event revealed that reactor power peaked at 101 percent and no automatic protective functions were required or actuated. A similar power transient occurred in December 23, 1993, during a flush of the letdown demineralizer when the boric acid transfer pump stopped during a blended makeup resulting in a boron dilution (refer to NRC Inspection Report 50-423/94-01).

In this recent event, the licensee was making preparations to perform the operational readiness test of the 'A' boric acid pump in accordance with surveillance procedure (SP) 3604C.4, "Boric Acid Pump 3CHS*P2A Operational Readiness Test". A procedure prerequisite required that the volume control tank (VCT) level be established greater than 50 percent. The control room operator (CO) performed the procedural steps out of sequence and was performing the system lineup in conjunction with establishing VCT level. This realignment resulted in diverting boric acid flow from the RCS to the BAT.

The licensee determined that the root cause of the event was personnel error. Procedure SP 3604C.4 is a continuous use procedure and as such requires that procedural steps be performed step-by-step in the order written. Deviation from the specified sequence is not allowed unless otherwise directed by the first line supervisor. In addition, a procedural precaution stated that the makeup to the VCT would not be available from either boric acid transfer pump due to the test alignment. As corrective action, the licensee removed the CO from shift and issued a memorandum to all operators regarding procedural compliance.

The inspector reviewed procedure SP 3604C.4 and concluded that it was adequate. A review of the licensee's plant information reports revealed that the number of personnel errors have declined since January 1993 at Unit 3. The inspector attributed this decline to increased management attention in this area and the implementation of the licensee's self-checking and work observation programs. Based upon the declining trend in personnel errors and in the action taken by the licensee to enhance procedure compliance, the inspector concluded that the licensee's corrective actions were acceptable. Since the event was licensee-identified and reported, and had minor safety significance, the criteria of Section VII.B of the NRC Enforcement Policy were met, and this violation will not be cited. The inspector's review of both boron dilution events revealed no root cause similarities. The inspector had no further questions.

2.7 Engineered Safety Features Walkdown - Unit 3

The inspector performed a detailed review of the Unit 3 emergency diesel generator (EDG) and the following EDG support systems: fuel oil (EGF), air start (EGA), intercoolant and jacket water cooling (EGS), and lubricating oil (EGO) systems. The inspection included a review of system alignment, equipment condition, associated operational surveillances, and a comparison of the plant system drawings to the as-built configuration.

The inspector noted that the EDG support systems were properly aligned, valves were labeled correctly, and no discrepancies were identified in equipment condition which would degrade system operability. During the walkdown, the inspector noted that valves EGS*V982B, and EGO*V993A/B and 994A/B were not listed in any valve line-up forms.

The subject valves were in the positions indicated on the piping and instrument drawings. The inspector informed the licensee of this condition and was informed that the subject valves would be added to the appropriate valve line-up forms.

During the walkdown, the inspector noted that the EDG lubricating oil temperature low and jacket water temperature low alarms were illuminated. This abnormal condition has existed for a number of years when the EDGs are in the standby mode. The lubricating oil is maintained heated by the lubricating oil keep warm system. This system is designed to maintain the temperature of the lubricating oil system between 120 degrees Fahrenheit (°F) and 125°F to permit the EDG to come up to rated speed within the technical specification (TS) specified 11 second time limit without delay for engine warmup. Within the past year, in an attempt to identify and eliminate the EDG low temperature alarms, the licensee has verified proper service water bypass flow rate to the EDG coolers, electric heater output from the lubricating and jacket water heaters, and inspected the check valves in the jacket water cooling system.

The inspector noted that on March 7, 1991, the licensee attributed the automatic tripping of the Millstone Unit 1 EDG on low lube oil pressure to low lubricating oil temperature. The licensee determined that the Unit 1 EDG operability was assured with a lubricating oil temperature above 68°F; no specific temperature has been determined for the Unit 3 EDGs. The inspector reviewed the plant operator's shiftly rounds and identified that operators record the diesel lubricating oil temperature shiftly and indicate whether it is below the expected value. A review of operator records indicates that the lubricating oil temperature has been as low as 90°F. To date, all routine EDG surveillance tests with the low lubricating oil temperature alarm actuated have not failed due to the low temperature condition. The EDGs were overhauled during the cycle 4 refueling outage (July - October 1994) and no adverse impact was noted on any power train components. The inspector noted that with the implementation of system engineers and management direction of an operational focus, the licensee has taken a more aggressive approach to resolve equipment problems. The inspector noted that the EDG system engineer trends EDG temperatures and has groomed the cooling water control system, which appears to have resolved the low lubricating oil and jacket water temperature concerns.

The inspector reviewed twenty EDG surveillance procedures to verify that they adequately test the EDG in accordance with TS requirements. The inspector's review of the procedures and test data revealed that the surveillance programs were implemented adequately, with one exception. While the backup fuel transfer pumps are tested to verify that they are capable of transferring fuel from each fuel storage tank to the opposite train day tank, they are not tested to verify the automatic start function on low-low day tank level. The inspector informed the licensee that if the lead fuel oil pump was inoperable and the backup pump was to be considered operable to maintain EDG operability, the automatic start feature would be required to be tested in accordance with technical specification 4.8.1.1.2. The licensee stated that the monthly surveillance procedure would be revised to incorporate the testing of the automatic start function of the backup fuel oil pump.

The inspector concluded that, based on procedure reviews, direct observations, and system walkdowns, the EDGs were operable. No discrepancies were noted which would degrade system performance. The inspector had no further questions.

3.0 MAINTENANCE (IP 62703, 61726)

The inspectors observed and reviewed selected portions of preventive and corrective maintenance and surveillance tests and reviewed test data to verify adherence to regulations and administrative control procedures; technical specification limiting conditions for operation; proper removal and restoration of equipment; appropriate review and resolution of test deficiencies; appropriate maintenance procedures; adherence to codes and standards; proper QA/QC involvement; proper use of bypass jumpers and safety tags; adequate personnel protection; and, appropriate equipment alignment and retest. The inspectors reviewed portions of the following work activities:

- M2-94-01510, Inspection of 'B' Emergency Diesel Air Start Distributor Cam.
- M2-94-01283, SP 2404A, Liquid Process Radiation Monitor Functional Test.
- M2-94-01281, SP 2401R, CEA Withdraw Prohibit (CWP) Functional Test.
- M2-94-01423, SP 2410A, Acoustic Valve Monitor System Functional Test.
- M2-94-01431, SP 24010, RPS Matrix and Trip Path Test.
- M2-94-01429, SP 2420E, Rod Motion Verification.
- M2-94-01482, SP 2401I, Local Power Density Test.
- M2-94-01604, SP 2403A, ESAS Bistable Trip & Automatic Test Inserter Test.
- M2-94-02468, Inspection of 'B' Emergency Diesel Air Start Distributor Cam.
- M2-94-02271, 'B' Emergency Diesel Preventive Maintenance.
- M2-94-02422, SP 2401D, RPS Matrix & Trip Path Test.
- M2-94-05419, 'A' RBCCW Heat Exchanger Quarterly PM.
- M3-90-07077, Replace Simplex Battery (Fire Protection Panel).
- M3-92-16944, Inspect Charging Pump Suction Cross Connect Valve Limitorque.
- M3-93-30249, Remove, Repair, Reinstall Service Water Pump SWP*PIB.
- M3-94-04183, Adjust Boric Acid Supply Valve (CHS*FCV110A) Position.
- SP2604G, Containment Sump Outlet Isolation Valve Operability Test, Z1.
- SP2654P, Weekly Inverter Ground Fault Surveillance.
- SP94-3-3, Monthly Turbine Control Valve Testing.
- SP3646A.1, Emergency Diesel Generator Operability Test.
- SP3448E31, Train 'A' Diesel Sequencer Actuation Logic Test.
- SP3604C.4, Boric Acid Pump 3CHS*P2A Operational Readiness Test.
- OP3646A.8, Slave Relay Testing - CTMT Spray Actuation.

Except as noted below, the inspectors determined that the maintenance and surveillance activities observed were performed adequately. Details of the inspector's observations are provided in Sections 3.1-3.6.

3.1 Troubleshooting Activities (Region I Temporary Instruction 94-01)

The inspector reviewed Millstone's troubleshooting process to assess whether troubleshooting activities were being implemented and controlled adequately. Procedure ACP-QA-2.02C, "Work Orders," establishes the administrative requirements for the performance of troubleshooting at Millstone Station. With the exception of the Unit 1 Instrumentation and Controls Department, no sub-tier implementing instructions exist, and the Unit 1 document conforms to the station procedure.

In accordance with procedure ACP-QA-2.02C, a written troubleshooting plan is required if the activity is performed on in-service equipment or could impact plant operation. The plan is documented on Station Form SF-250 (or other written documents) and implemented through automated work orders (AWOs) which must be authorized by the Operations Department. In addition, the initial plan, and subsequent changes, must be discussed with the shift supervisor prior to performance. The discussion must include the following attributes:

- Roles of troubleshooting personnel
- Troubleshooting boundaries
- Expected system responses and interactions
- Personnel safety precautions
- Estimated time of completion of the troubleshooting
- Precautions to prevent unplanned radiological releases

In the event that the activity covers more than one operating shift, provisions are made for turnover and additional briefings; each shift must be apprised of the troubleshooting plan. Except for tightening of loose electrical leads, connections and/or plugs, no corrective maintenance is authorized under a troubleshooting AWO unless the scope of the AWO is changed and reviewed per the normal work control process. Customarily, a new AWO is initiated to perform repairs.

The inspector observed several troubleshooting activities at all three units, particularly the activities concerning a vital 120 volt ac inverter which was performed at Unit 2 under AWO M2-94-01638. The AWO package contained a detailed plan (SF-250), and the plan was discussed thoroughly with the shift supervisor prior to authorizing work. A shift briefing was conducted which covered the scope activity and expected system responses. In the field, the inspector verified that personnel adhered strictly to the plan. Subsequent changes to the plan were discussed with the shift supervisor, who briefed the operating crew, prior to continuing the troubleshooting. The inspector concluded that the troubleshooting was well planned and properly executed.

The inverter troubleshooting was witnessed by a licensee quality assurance services (QAS) inspector as part of the Millstone Work Observation Program. The QAS inspector identified several opportunities to enhance the troubleshooting procedure. The licensee is evaluating the recommendations as part of a planned effort to upgrade its administrative procedures.

Based on procedure review and observation in the field, the inspector concluded that troubleshooting activities are controlled adequately by the licensee's work order process. In addition, the inspector concluded that the QAS Department work observation of vital inverter troubleshooting was a high quality effort.

3.2 Safety Relief Valve Failure - Unit 1

On March 29, 1994, the licensee determined that the six reactor coolant system safety relief valves that were installed in the plant during the cycle 14 operating period did not open at the setpoint that was specified in Technical Specification (TS) 3.6.D, Primary System Boundary. The licensee reported the occurrence to the NRC per 10 CFR 50.72(b)(2)(iii)(C) as any event or condition that alone could have prevented the fulfillment of a safety function.

The safety relief valves were tested by WYLE as required by TS 4.6.E, Safety and Relief Valves. The TS requires the relief valves to lift within one percent of its setpoint. Although the TS specifies that a minimum of three relief valves shall be tested each refueling outage, Unit 1 tested all six. All six valves lifted at pressures that were greater than one percent of the setpoint when tested. Two valves did not open at all when subjected to maximum overpressure of 112.2 percent of the valve setpoint. The amount of pressure that was required to open the other four valves ranged from 102 to 109.9 percent of set pressure.

One of the functions of the safety relief valves at Millstone Unit 1 includes preventing the overpressurization of the reactor pressure vessel in the event the Main Steam Isolation Valves (MSIVs) go closed when the reactor is at 100 percent of rated thermal power. The safety valves at Unit 1 are two stage Target Rock relief valves that contain a small pilot valve and larger main valve seat. During plant operation, if the valve is subjected to an overpressure condition, the pilot valve will open first and allow pressure to equalize on both sides of the main valve disc. Once pressure has equalized, the main disc will open allowing the valve to discharge. The inspector noted that since 1987, 20 out of 24 valves tested, at Unit 1 had failed to lift within the margin required by TS.

Setpoint "drift" of the two stage target rock relief valves has been an industry-wide problem. The Boiling Water Reactor Owners Group (BWROG) believes that oxide buildups on the relief pilot valve disk, bonds the pilot disc to the seat, and causes an upward "drift" in setpoint. The oxide buildup comes from the radiolytic dissociation of water into elemental components of hydrogen and oxygen. The licensee has concluded that oxygen concentrates in the pilot valve area causing an oxide film buildup. During this refuel outage, the licensee installed a stellite/platinum disk in the pilot valve in three of the relief valves that are set at 1125 psi. The platinum material is intended to act as a catalyst that would recombine the excess oxygen and hydrogen in the pilot valve area, and consequently reduce the oxide buildup on the pilot valve seat. The remaining three relief valves will continue to utilize the original stainless steel seating material.

The licensee is currently performing a plant specific analysis to evaluate what affect, if any, the setpoint drift would have on the plant safety analysis. The licensee is also considering what measures could be taken during the current operating cycle to ensure operability of the relief valves during the current operating cycle.

The inspector noted that based upon the historical performance of the relief valves, it could not be determined if the setpoint of the relief valves would remain within the TS specified tolerance during the next operating cycle. Therefore, the inspector concluded that the installation of the platinum seating material in three relief valves, and the consideration of additional testing of the relief valves during the next cycle were prudent measures. This item will remain **unresolved** pending NRC review of the licensee plant specific analysis of the consequences of the relief valve failures and the implementation of measures to assure the operability of the relief valves during the upcoming operating cycle. **(URI 245/94-14-01)**.

3.3 Failure of Reactor Recirculation Pump Field Breaker - Unit 1

On January 25, 1994, the field breaker for the 'B' reactor recirculation pump motor generator set did not open when operators attempted to secure the 'B' recirculation pump. In response to the failure, operators dispatched a plant equipment operator (PEO) to the motor generator control cabinet to investigate. The PEO reported that the field breaker did not trip and smoke was emanating from the cabinet. The plant fire brigade was summoned as a precaution and power to the breaker trip coil was removed by pulling the trip coil control power fuses.

Licensee investigation revealed that one of the breaker trip coils that is used to open the main contacts of the field breaker had failed. The trip coil opens the field breaker by energizing to trip open the main breaker contacts. Once the breaker opens, the trip coil is deenergized. The coil is not rated for continuous duty and will overheat and fail if subjected to full voltage for more than a few seconds. According to the licensee, when the breaker trip coil was energized, hardened grease on the breaker opening mechanisms prevented movement of the main breaker contacts. Consequently the trip coil overheated and failed. The motor generator field breaker was a General Electric model AKF-2-25. The field breaker on the 'A' recirculation system motor generator set also opened slowly when it was tested by the licensee.

Each of the field breakers contains two trip coils. One of the trip coils for the recirculation pump motor generator set is a dedicated component of the Anticipated Transient Without Scram (ATWS) system at Unit 1. If an ATWS condition existed at Unit 1, the system is designed to stop the recirculation pumps by opening the field breakers for the recirculation system motor generator sets. In addition to opening the field breakers, the scram air header is depressurized by energizing the alternate scram valves. The second coil is also part of the ATWS system and is redundant to the first. However, the second coil is also part of the normal breaker trip circuitry and therefore is energized when an operator opens or closes the breaker. This is the coil that failed on January 25, 1994. Once per refuel cycle, the licensee ensures that the ATWS trip coil is operable by inserting a simulated ATWS signal to the coil and verifying that the breaker opens.

The inspector noted that NRC information Notice 87-12, "Potential Problems with Metal Clad Circuit Breakers, General Electric Type AKF-2-25," identified that many AKF-2-25 breakers throughout the industry had failed to operate when required because of several deficiencies, which included hardened grease on breaker internals and poor preventive maintenance activities. To improve breaker performance, the Information Notice made several recommendations which included performing preventive maintenance on the breakers at 12 month or once per refuel cycle intervals and revising the type of lubricants used on the breakers. A similar preventive maintenance program was also highlighted in a 1986 General Electric Service Information Letter (SIL) that highlighted AKF-2-25 breaker problems. In response to the GE SIL, the licensee revised the breaker preventive maintenance program to include an overhaul once every five years and preventive maintenance every 18 months. A review of the preventive maintenance history for the breakers revealed that they were cleaned and inspected during the 1991 refuel outage but have not been examined since that time.

Based upon a review of the 'B' motor generator set field breaker failure, the inspector concluded that a poor breaker preventive maintenance program may have rendered portions of the ATWS system inoperable for an indeterminate period of time. The inspector noted that the licensee's maintenance program may have prevented the breaker failure if it was adjusted to reflect the increase in cycle length that has occurred as core lifetimes have been extended or operational problems extend plant operation the normal fuel cycle. The inspector noted that other plant components have also failed during plant operating cycles because the licensee did not adequately assess what impact an extended operating cycle would have on plant components. Specifically, as reported in NRC inspection report 50-245/93-24, pressure control isolation valve 1-CU-10 degraded and failed because the component that needed to be overhauled approximately every two years to ensure operability had not been maintained in the past three years due to an extended operating cycle.

To ensure the field breakers would be operable, the licensee replaced the failed breaker with an installed spare. The breaker on the 'A' recirculation motor generator set was rebuilt. Based upon the failure of the 'B' breaker, the licensee will perform preventive maintenance on the breakers during the next shutdown period that occurs 12 months after plant startup. The inspector concluded that the corrective actions for this discrepancy were adequate. Licensee response to and tracking of vendor information and NRC Information Notices has been a noted licensee performance weakness in the past. Licensee corrective actions to resolve this concern are being tracked by open inspection items **URI 423/91-12-03** and **URI 423/93-13-07**.

3.4 **Emergency Diesel Generator Solenoid Valve Maintenance - Unit 1**

The inspector reviewed maintenance performed on the safety-related diesel generator air start system solenoid-operated valves (SOVs) to verify that the technical specification and quality assurance requirements governing that activity were met. As documented in automated work orders (AWOs) M1-92-05707 (valve AS-1) and M1-92-05726 (valve AS-2) dated February 26, 1994, the work consisted of overhauling the valves using commercial grade rebuild kits and solenoid coils supplied by the SOV manufacturer (Automated Switch Company - ASCO). The inspector could not determine from the work documents the precise date on which the maintenance was conducted. However, through discussions with the work control center personnel and the job supervisor, the inspector determined that the rebuild kits were installed on or about March 3, 1994, when the SOVs were removed from the air start system. The work was performed using a vendor installation and maintenance bulletin which applies to six different SOV models. The inspector reviewed the vendor bulletin and concluded that this complex maintenance activity exceeded the skills normally possessed by qualified maintenance personnel and that the bulletin, alone, was insufficient to assure that the component integrity/qualification of the SOVs was preserved. Technical Specifications 6.8.1.a and 6.8.2, respectively, require written procedures to be established covering the procedures recommended by Regulatory Guide (RG) 1.33, Quality Assurance Program Requirements (Operation), and that the procedures be reviewed and approved by the plant operations review committee (PORC). RG 1.33, step 9.a, requires that maintenance performed on safety-related equipment be performed in accordance with written procedures appropriate to the circumstances. Pursuant to the above, administrative control procedure ACP-QA-2.02C, "Work Orders," step 6.2.9.1, states that a unit-approved procedure is required for the disassembly, repair, and reassembly of all Quality Assurance Category I (safety-related) equipment whenever implementation requires unique or complex instructions. The inspector concluded that rebuilding the diesel generator air start SOVs without a PORC-approved procedure was a violation of these requirements.

The inspector presented these findings to the Unit 1 Maintenance and Outage Managers, who agreed that an approved procedure should have been used to overhaul the SOVs. The licensee initiated nonconformance reports on the valves, and the maintenance was reperformed using a new, PORC-approved procedure. The inspector verified through review of the procedure, field observations, and discussions with maintenance personnel that the appropriate quality attributes were designated and independently verified. The inspector concluded that the licensee's immediate corrective action regarding the diesel air start SOV rebuild procedure was acceptable. The licensee also initiated a plant information report to determine the extent to which maintenance on other safety-related equipment may have occurred, and to develop actions to prevent recurrence. The licensee stated that no similar problems had been identified regarding work performed on main steam isolation, safety relief, or control rod scram pilot SOVs. However, the inspector concluded that the licensee's action to prevent recurrence was not sufficiently comprehensive (the scope of the licensee's initial reviews was narrowly focused) to assure that maintenance on other safety-related components at Unit 1 had been controlled properly by PORC-approved procedures. Therefore, this NRC-identified **violation** will be cited. (**VIO 245/94-14-02**)

The inspector also reviewed the AWOs to assess the quality assurance aspects of the SOV maintenance against the provisions of procedure ACP-QA-2.02C. The procedure establishes personnel responsibilities for initiation, independent review, and authorization of work on safety-related (Category I) equipment, and provides criteria for invoking Plant Quality Services Department inspection and surveillance of maintenance activities. In general, procedure ACP-QA-2.02C requires the maintenance department (or work control center) planner and the department supervisor to verify independently that important quality attributes in AWO packages are identified and verified by inspections and tests. The SOV work orders were initiated, reviewed, and approved by the same individual, the work control center planner, thus bypassing the line supervisor review function. No inspections of quality attributes were identified. The inspector noted, however, that the ASCO maintenance bulletins placed in the AWO packages contained several aspects of the SOV overhaul which were critical to maintaining the quality and seismic qualification of the valves, including: selection of spring pairs; choice and application of lubricants; cleanliness; disk stroke setting; and torquing of the explosion-proof solenoid cover, solenoid base subassembly, valve seats, and disc guide cap screws. The inspector found no other documentation that the quality of these safety-related SOVs was maintained through independent verification of the maintenance activity.

Procedure ACP-QA-2.02C provides guidelines for quality control involvement in safety-related work activities and criteria for determining whether inspection hold points are required. The planner's determination that no quality services department involvement was required for the SOV job appeared to have been consistent with these guidelines. The inspector concluded that the maintenance activity lacked the element of independent verification and supervisory oversight necessary to assure quality and recommended to licensee management that the policies set forth in procedure ACP-QA-2.02C be reevaluated. This matter is **unresolved** pending review of the licensee's response to these concerns. (**URI 245/94-14-03**).

3.5 Commercial Grade Dedication of Solenoid Valve Rebuild Kits - Unit 1

The diesel generator air start system solenoid-operated valves (SOVs) were installed in 1985 per plant design change record 1-97-85 and Northeast Utilities Service Company Design Specification SP-ME-495. The SOVs (ASCO model 121-631-1RG) were procured commercial grade, dedicated, and seismically qualified by test in accordance with the design specification and IEEE Standard 344, Recommended Practices For The Seismic Qualification Of Class 1E Equipment For Nuclear Power Generating Stations. As detailed in Section 3.4 above, the SOVs were rebuilt in March and April, 1994, using the parts contained in commercial grade rebuild kits. 10 CFR Part 50, Appendix B, Criterion III, Design Control, requires licensees to assure that parts are suitable for their intended safety functions by identifying important design, material, and performance characteristics, establishing acceptance criteria, and providing reasonable assurance of conformance to those criteria. Pursuant to these requirements, licensee procedure ACP-QA-4.03A, "Upgrading Spare Parts For Use In QA Application - Commercial Grade Item Procurement And Dedication," Revision 7, dated October 23, 1990, was used in February 1991 to dedicate the commercial grade SOV rebuild kits. Step 6.1.2.e of the procedure required a technical evaluation to be performed of any differences between the originally installed and the replacement parts. Specifically, per step 6.1.2.f of the procedure, the licensee was required to identify and verify by inspection and/or test the critical characteristics relevant to the seismic qualification of the SOVs. Also, Attachment 8.2 of the procedure stated that changes in assembly or types of materials should be considered, and that verification of design controls, modifications to internal part characteristics, and assembly procedures should be considered if maintaining seismic qualification is an issue.

The inspector reviewed the commercial grade dedication forms for the rebuild kits and replacement coils, and inspected in the warehouse a kit and coil which had been procured by the licensee under the same purchase order as those used to overhaul the SOVs. The licensee had concluded that the new parts were like-for-like (identical) replacements based on inventory verification that the kits contained the parts listed by the manufacturer. However, the licensee did not ascertain through direct comparison that the rebuild kit parts and coils were identical to those installed in the seismically tested SOVs; nor did the licensee verify that the rebuild kits contained the stainless steel discs and resilient seats called for in the SOV design specification. In addition, critical characteristics relevant to seismic qualification of the SOVs, such as weight, types of material, dimension, and/or spring constant were not identified or evaluated in the dedication packages.

On April 8, 1994, the licensee initiated a nonconformance report (NCR) to address the seismic qualification of the rebuilt SOVs, and satisfactorily performed a special test of the diesel generator to verify SOV functionality. Using engineering judgement, the licensee concluded that the rebuilt SOVs were acceptable, based on the following considerations:

- The replacement parts were designed and manufactured by ASCO explicitly for the valve model installed in the diesel air start system.

- Since the new parts fit properly in the valve, the licensee inferred that valve weights and center of gravity were not significantly affected. Seismic performance of the valve is dominated by the mass of the valve plunger, compared to which the mass of the replaced parts is insignificant.

- Satisfactory operability tests of the diesel generator demonstrate that changes in valve spring constant, if any, are not seismically significant.

The inspector concluded that the NCR disposition was acceptable and that the seismic qualification of the SOVs had not been affected adversely by the parts replacement. Nonetheless, the inspector also concluded that the licensee's initial commercial grade dedication of the new parts did not satisfy the requirements of 10 CFR Part 50, Appendix B, or procedure ACP-QA-4.03A. The inspector also noted that a similar deficient dedication of commercial grade diesel generator air start SOVs at Unit 2 had been identified by the NRC in late 1993, and concluded that the lessons learned from the Unit 2 experience appeared not to have been communicated effectively to Unit 1. Also, the licensee did not initiate an assessment of other potentially deficient commercial grade dedications installed at Unit 1 during the current outage until prompted by the inspector. For these reasons, the **violation** of NRC and licensee design control requirements discussed above will be cited. (**VIO 245/94-14-04**).

In reviewing the work order packages for the SOV maintenance, the inspector also found that the rebuild kits and coils had been conditionally accepted by the Plant Quality Services Department for installation in the plant pending performance of a diesel generator operability test. The test was specified in the commercial grade dedication forms as a critical characteristic. Procedure ACP-QA-2.02C, step 6.6.1.29.a and an accompanying note, requires that commercially dedicated parts be controlled per the requirements of procedure ACP-QA-4.03A (Revision 10, dated July 1992). Steps 6.5.3 and 6.5.3.2 of that procedure require the Job Supervisor to transfer the tests specified by the commercial grade dedication forms to Station Form 1419, Product Acceptance Test/Preoperational Test, and require the Plant Quality Services Department to review the work order package. Contrary to these requirements, the work order packages for the SOVs did not contain the specified forms, and had not been reviewed by the Plant Quality Services Department. This is an additional example of the failure to meet commercial grade dedication requirements cited above.

3.6 Enclosure Building Filtration System Test Deficiency - Unit 2

The enclosure building filtration system (EBFS) is designed to draw a slightly negative pressure within the enclosure building following a loss of coolant accident (LOCA). Operability of the system ensures that leakage of radioactive material from the containment building to the enclosure building during LOCA conditions will be filtered through high efficiency filters and charcoal absorber trains prior to discharge to the atmosphere. The requirement is necessary to meet the assumptions used in the Unit 2 accident analyses and to limit radiation doses at the site boundary to within 10 CFR Part 100 limits. In order to maintain filter efficiency, electric heaters are installed to limit the relative humidity of the air entering the filter housings to less than 60 percent. Two independent EBFS trains are required by Technical Specification (TS) 3.6.5.1 to be operable in operating modes one through four. Operability of the EBFS is demonstrated, per TS 4.6.5.1.a, every 31 days by running the system at least 10 hours with the heaters on. Procedures SP-2609A and SP 2609B, "Enclosure Building Filtration and Control Room Ventilation Operability Tests," implement the surveillance requirement. During an EBFS walkdown, the inspector reviewed the procedures and noted that the acceptance criterion for heater operation was the absence of a high system moisture alarm. (Alarm setpoint greater than 50 percent relative humidity.) The inspector concluded that the surveillance acceptance criterion for heater operation was inadequate, because with no heaters operable, the high moisture alarm would not actuate if, as is normally the case, the relative humidity of the air entering the filters is less than 50 percent.

The inspector informed the licensee of the discrepancy on April 1, 1994, at 2:30 p.m. The licensee examined the EBFS heater electrical circuit diagrams and found that the heaters are controlled by a moisture switch which is set at 65 percent relative humidity. Since no moisture alarms had been present during previous surveillance tests, the licensee concluded that the heaters, and hence the EBFS, had not been demonstrated to be operable. The licensee entered TS 3.0.3/4.0.3. TS 4.0.3 allows the licensee 24 hours to complete surveillance requirements which have not been satisfied prior to implementing the plant shutdown actions required by TS 3.0.3. The licensee initiated a plant information report to document the event and determined that the event was reportable to the NRC pursuant to 10 CFR 50.73 (Licensee Event Reports). Procedure SP-2609B was changed to install a temporary jumper across the moisture switch, and to verify heater operation by measuring current through the heaters and a temperature rise across the filters. The inspector observed the performance of portions of the changed surveillance test, and identified no discrepancies. On April 2, at 12:44 p.m., the 'B' train EBFS was declared operable and the seven-day limiting condition for operation (LCO) of TS 3.6.5.1 for one EBFS train inoperable was entered. On April 3, the licensee successfully completed the operability test for the 'A' train EBFS and exited the LCO. The inspector concluded that EBFS heater operation had been demonstrated adequately and that the licensee's immediate corrective actions had been timely and acceptable.

Technical Specifications 6.8.1.c and 6.8.2, respectively, require the licensee to establish and implement surveillance procedures for safety-related equipment and to review the procedures periodically. In addition, TS 6.5.3.7.a requires the Unit 2 Nuclear Review Board to perform an audit of unit conformance to the provisions contained in the TS. The inspector discussed with the licensee the apparent failure of these mechanisms to identify the surveillance procedure deficiency. The licensee agreed to address these concerns in the licensee event report. Also, in reviewing the EBFS operating procedure and applicable sections of the Unit 2 Final Safety Evaluation Report (FSAR), the inspector identified the following apparent discrepancies:

- Procedure OP-2314G instructs the operator to run the EBFS with the heaters energized for two hours upon receipt of a high moisture alarm (i.e., greater than 50 percent humidity). However, the heaters will not energize until relative humidity reaches 65 percent. Therefore, the intent of the procedure may be compromised.

- Section 6.6.4.2 of the FSAR states that EBFS heaters and the associated control system are visually inspected to assure operation of the containment purge isolation valve/heater override (interlock) function. The licensee was unable to provide documentation of the completion of this inspection.

- Section 6.7.2.1 of the FSAR states that the EBFS heaters maintain relative humidity of the air entering the filter units to less than 60 percent. This appears to be inconsistent with the EBFS switch setpoint (65 percent).

These matters are **unresolved** pending NRC review of licensee corrective actions and actions to prevent recurrence, including resolution of the apparent discrepancies described above. **(URI 336/94-11-05)**

4.0 ENGINEERING (IP 37700, 37828)

4.1 Emergency Service Water Design Deficiency Discovered - Unit 1

On March 28, 1994, the licensee informed the NRC that the Emergency Service Water (ESW) system could not be operated in accordance with its design criteria following a design basis loss of coolant accident (LOCA) event. Specifically, following the initial low pressure coolant injection (LPCI) into the reactor, systems are realigned by the operators for torus cooling. The ESW system is started and service water is directed to the LPCI/ESW heat exchangers. LPCI system flow is then diverted through the LPCI/ESW heat exchangers to enable cooldown of the torus and containment structure. To ensure that leakage through the LPCI/ESW heat exchanger is not released into the ESW system, the pressure in the ESW system is maintained fifteen pounds above the LPCI system pressure.

Because the ESW system discharges to the environment without continuous radiation monitoring, maintaining this overpressure is critical to assure no offsite radiological hazard develops in the torus cooling mode. However, as the temperature of the torus water increases, LPCI system flow must be decreased to prevent pump cavitation. The LPCI flow is throttled using the outlet valve of the LPCI/ESW heat exchanger. Therefore, when flow is decreased, LPCI system pressure will correspondingly increase, necessitating a decrease in ESW system flow to maintain the required fifteen pound differential pressure. The licensee determined that if LPCI system flow is reduced to the required minimum flow of 1000 gallons per minute, the 15 pound ESW overpressure cannot be assured across the heat exchanger. The licensee reported this event per 10 CFR 50.72(b)(1)(ii)(B) as a condition that was outside of the plant design basis.

The licensee identified the potential design deficiency while developing a computer based model of the ESW system. The model was being developed by the licensee in an effort to understand the performance of the ESW system as recommended in NRC Generic Letter 89-13. According to the licensee, the model predicted the 15 pound differential pressure across the LPCI heat exchanger could not be assured assuming the worst case heat exchanger fouling, ESW pump performance, and ESW and torus temperatures. At the close of the report period, the licensee had not decided how to mitigate the ESW design deficiency. Such action will be required prior to plant startup from the current refueling outage. Several possible courses of action included installation of radiation monitors on the outlet of the ESW system that would inform operators of LPCI heat exchanger leakage or taking grab samples of the ESW system water on a periodic basis when the differential pressure could not be maintained.

The inspector noted that the discovery of the potential ESW design deficiency demonstrated that the licensee is making a concerted effort to verify the performance characteristics of the plant service water systems. An inspector **follow item** will be opened pending NRC review of the licensee's dispositioning of the ESW design deficiency. **(IFI 245/94-14-06)**

4.2 Reactor Vessel Setpoint Inadequacy Discovered - Unit 1

While reviewing the methodology that was used to develop the reactor vessel level trip setpoints, the licensee discovered that the trip setpoints, which initiate a reactor scram or Engineered Safety Features (ESF) actuation were not set at the level that was described in the Unit 1 technical Specifications (TSs). Specifically, TS 3.2, Protective Instrumentation, states that the reactor trip and ESF setpoints should be set at 127 and 79 inches above the top of the active fuel, respectively. However, the licensee discovered that the trip setpoints were actually set at 125.75 and 77.75 inches above the top of the fuel.

The incorrect setpoints were developed during the late 1970's when the licensee changed from General Electric (GE) 7X7 to GE 8X8 array fuel assemblies. According to the licensee, the GE 8X8 fuel is approximately 1.25 inches longer than the GE 7X7 assemblies. The reactor vessel level trip setpoints were not adjusted based on this difference. Apparently, the licensee did not adequately assess how the increase in fuel length would affect the trip setpoints that are contained in the plant TS. The incorrect trip setpoints did not, however, affect the plant reload analyses since the reactor vessel level assumptions in the analyses are referenced to the bottom of the reactor vessel rather than the height of the fuel.

To resolve the issue, the licensee processed a setpoint change to restore the trip setpoints to 127 and 79 inches above the current top of the active fuel. The licensee stated that a future TS change would be processed to make the basis by which the setpoints are established consistent with the accident analysis assumptions. Specifically, the licensee intends to change the TS to reference the setpoints to a set height above the bottom of the reactor vessel, a fixed point, rather than the top of the fuel.

A Licensee Event Report will be prepared to document the failure of the setpoint to be positioned as stated in the plant technical specifications. The inspector considered the licensee's corrective action to be appropriate. The issue had minor safety significance since the plant safety analyses did not use the height of the active fuel as a reference point. Therefore, per section VII.B of the enforcement policy, no violation will be issued.

4.3 Evaluation of the Potential for an Explosion in the Plant Stack - Unit 1

A hydrogen explosion occurred in the base of the plant stack in early 1978 when a spark from a sump pump detonated significant quantities of trapped hydrogen gas induced from the condenser off-gas 30 minute hold-up line, causing significant stack damage and the potential for serious personnel injury. The NRC became aware of a recent concern that opening the stack access door to sample for hydrogen prior to entry caused a ventilation fan to start creating the potential for another explosion. Unit 1 engineering reevaluated the potential for a hydrogen explosion in the base of the plant stack due to either a spark or a change in atmospheric composition upon periodic personnel entry into the stack base.

Unit 1 engineering evaluated the design changes to the ventilation flow to the lower stack area following the 1978 explosion which included: 1) redundant ventilation exhaust blowers in the stack base, one of which is always running, and an alarm in the control room annunciates a loss of vacuum in the stack base; 2) a ventilation damper which diverts 2000 CFM of stack air flow into the base area; 3) removal of a plug in the stack lower floor to allow for a free flow of air from the stack base; 4) removal of loop seals on the 30 minute hold-up line (this line is now very rarely used - the current augmented off-gas system was placed in service shortly after this event and has provisions for hydrogen gas recombination); and, 5) administrative controls governing the atmospheric sampling of the stack base prior to entry and key control to the lower stack access door. The cumulative effect of these changes were considered by Unit 1 engineering to be more than sufficient to prevent the accumulation of hydrogen at or near levels capable of supporting combustion; thus since no threat to personnel safety existed, no further action was planned.

The inspector toured the stack base with the responsible Unit 1 engineer to evaluate the condition of the ventilation system equipment, as well as, the air flow pattern in the stack base. The inspector noted that the condition of the ventilation system equipment was good, and the air flow pattern in the stack base precluded a long term build-up of hydrogen gas. The very limited use of the 30 minute hold-up line as well as the removal of the loop seals on that line preclude significant amounts of hydrogen gas from being introduced into the stack base. The redundant fan design provides constant circulation and the start of the backup fan on each stack entry adds no other spark hazard than the running fan. However, the ventilation damper which allowed airflow into the lower base of the stack was nearly closed and clogged with debris, allowing substantially less than the 2000 CFM designed into the base of the stack. The responsible engineer and his supervisor were pursuing maintenance corrective action to position and clean the ventilation damper to restore the intended 2000 CFM airflow.

The inspector considered the evaluation by Unit 1 engineering of this matter to be technically satisfactory given the extensive corrective actions pursued after the 1978 event. However, the positioning and cleaning of the ventilation damper should have been verified to confirm Unit 1 engineering's conclusion in this matter. The inspector considers the potential for a hydrogen explosion in the stack base to be minimal even with the limited airflow afforded by the ventilation damper condition noted above, although maintenance of the damper position and cleaning is necessary to restore the original design assumptions of the ventilation system and to avoid an excessive vacuum force on the stack base access door. The inspector had no further questions at this time.

4.4 Lack of Electrical Separation - Unit 2

On March 10, 1994, during a design review of Foxboro SPEC 200 instrument loops, the licensee identified a nonconformance in the electrical isolation scheme between the safety-related reactor coolant system (RCS) cold leg temperature loop, and the non safety-related feedwater regulating system (FWRS) control loop. The FWRS receives an RCS cold leg temperature input for temperature compensation. The lack of isolation between the RCS cold leg temperature protection loops and the FWRS control loops could result in the propagation of a fault in the non-safety grade cabinets RC31A and RC31B to class 1E cabinets RC30A and RC30B. The nonconformance was due to the incorrect implementation of plant design change request (PDCR) 2-029-83, which replaced the cold leg Rosemount resistance temperature detectors (RTDs) with Weed fast response RTDs, and also replaced the FWRS for both steam generators. The lack of isolation of the class 1E instrument loops does not meet the protection and reactivity control systems requirements of General Design Criterion (GDC) 24 of 10 CFR 50 Appendix A, or IEEE 279-1971, which specify that protection systems must be isolated from control systems through isolation devices.

The licensee notified the NRC of a potential condition outside the design basis, in accordance with 10 CFR 50.72(b)(1)(ii), and initiated an operability evaluation for the devices contained in cabinets RC30A and RC30B. Based on an evaluation of postulated failures, vendor correspondence, and the successful completion of surveillances for affected instrument loops, the licensee concluded that there are no failure modes which could prevent the actuation of the protection instruments housed in RC30A and RC30B, and the equipment contained in those cabinets is capable of performing their safety function. Therefore the devices contained in cabinets RC30A and RC30B were considered operable. This issue remains **unresolved** pending the inspector's evaluation of the licensee event report (LER) and corrective actions. **(URI 336/94-11-07)**

4.5 Condition Potentially Outside the Design Basis - Unit 3

On March 15, 1994, with the plant operating at 100 percent power, the license reported a condition outside the design basis of the plant in accordance with 10 CFR 50.72(b)(ii)(B). The licensee reported that the 'A' auxiliary feedwater (AFW) supply line support configuration was not designed in the same manner as the other three supply lines and therefore may not meet design requirements due to inadequate pipe restraints. An engineering review of an in-house safety system functional inspection (SSFI) observation has identified that the line may be inadequately designed for high energy line breaks (HELBs). This condition has existed since the first cycle of plant operation (April 1986).

High energy line break design criteria are assumed for equipment used for normal plant operations and are not applicable to equipment used for emergency or upset plant conditions. As immediate corrective action, the licensee issued a night order to operations personnel precluding operation of the AFW system for normal plant operation. In addition, caution tags were placed on the 'A' AFW supply line to alert operators of this condition. The licensee considered the AFW system operable to perform its safety function and a plant shutdown was not warranted. A structural evaluation of the AFW line and its associated supports is currently being performed to determine the adequacy of the as-built design for HELB concerns. If it is determined that the line is inadequate, the original design intent will be restored by upgrading the AFW line supports.

The inspector verified that caution tags were hung and operations personnel were aware of the restrictions in using the AFW system for normal plant operation. The inspector concluded that adequate action had been taken to preclude AFW system operation in other than emergency operation. Licensee completion of the final resolution regarding the adequacy of the AFW line supports will be tracked by NRC as **unresolved item (URI 423/94-11-08)**.

4.6 Erosion of Cement Under the Containment Basemat - Unit 3

Unit 3 engineering is evaluating an observed erosion/leaching of the cement from the nine inch thick porous concrete (calcium aluminate) layer which underlays the Unit 3 containment basemat. This erosion/leaching was first noticed in 1987 by the accumulation of concrete residue in the two engineered safety features (ESF) building lower drain sumps. Perforated drainage piping from the upper porous concrete layer drain into these sumps. To date, the amount of material collected represents less than 1% of the total cement content of the porous concrete. Mock-up test results to date have noted that the porous cement is able to maintain its nesting structure intact when confined laterally. Under this condition, the aggregate is able to retain sufficient strength as a load bearing media, justifying the continued safe operation of the plant in its present condition.

The inspector discussed with Unit 3 engineering the actions taken to evaluate and analyze this problem and, if necessary, pursue corrective actions. The licensee currently has ongoing a mock-up test of the problem at a research laboratory. Based on the results of this testing program (due by June 1994), the licensee plans to evaluate the long-term significance of this erosion/leaching problem and decide on corrective actions. Mock-up testing results and chemical analysis of the cement sludge collected to date indicates that the cause of the problem is a chemical reaction between the porous cement and the containment basemat (Portland cement), not erosion as originally believed. This process is probably facilitated by the flow of ground water around the containment basemat to the porous concrete interface. The inspector noted that the leaching rate of the concrete is believed to be constant and dependent only on water flow through the porous concrete. Unit 3 is also pursuing inspection of the other three drainage sumps in the plant outside the ESF building as well as any indication of the settlement of plant structures since original plant construction. There have been no adverse findings to date.

The inspector reviewed the drainage patterns for ground water and concrete residue into the two ESF building sumps. The presence of radioactive contamination in these sumps and the potential for an unmonitored release path to the environment are discussed in NRC Inspection Report 50-423/94-14. Unit 3 engineering is reviewing both the concrete degradation and contamination issues in the course of resolving this matter. The inspector will **follow-up** on the technical resolution of this issue, corrective actions implemented including licensee review of the drainage pattern into the two lower ESF sumps. **(IFI 423/94-11-09)**

5.0 PLANT SUPPORT (IP 71707)

The accessible portions of plant areas were toured on a regular basis. The inspectors observed plant housekeeping conditions, general equipment conditions, and fire prevention practices. The inspectors also verified proper posting of contaminated, airborne, and radiation areas with respect to boundary identification and locking requirements. Selected aspects of security plan implementation were observed including site access controls, integrity of security barriers, implementation of compensatory measures, and guard force response to alarms and degraded conditions. The inspector noted that graffiti located in the Unit 2, 'A' safeguards room was still present, though it had been identified to the licensee in December 1993. The following additional activities were reviewed.

5.1 Transport of Contaminated Worker Offsite - Unit 1

On February 22, 1994, a worker was transported to an offsite hospital after he had fallen into a contaminated Unit 1 condenser waterbox. The individual was a boilermaker who was working on the condenser tube replacement project. According to the licensee, the worker was injured when a section of water box staging collapsed which allowed the worker to fall approximately six feet. As a result of the fall, the worker had apparently injured his left shoulder. The individual was subsequently assisted from the water box by health physics personnel and his protective clothing (PC) was removed from the chest down. The PCs were not removed from his upper torso area due to the nature of his injury. Subsequent frisking of the individual while in the ambulance revealed slight contamination of up to 200 corrected counts per minute on the remaining portions of his PCs. Since the worker was potentially contaminated while being transported offsite, an Unusual Event was declared and reported in accordance with the licensee's site emergency plan per 10 CFR 50.72(a)(2)[v]. Once the worker arrived at the hospital the remaining portions off his PCs were removed and returned to the site. The worker was then frisked and unconditionally released along with emergency attending personnel and the hospital area.

The section of staging that broke consisted of 3/4 inch plywood planks spanning the condenser waterbox separator plates. The plywood had been placed across rods, which were inserted into condenser tube holes. According to the licensee, the worker was injured when he was moving between two different levels of staging. The worker, who weighed over 300 pounds, jumped from a height of two feet onto the lower section. The impact of the worker's movement collapsed the staging.

To prevent recurrence of this event, the licensee maximized the use of thicker one piece sections of wood planking for staging on the interior waterbox areas vice the 3/4 inch plywood. The inspector concluded that use of the heavier planking was a prudent corrective action.

5.2 Radiological Protection Controls - Unit 3

The inspector observed the implementation of selected portions of the licensee's radiological controls program. The inspector monitored the ALARA (As Low As Reasonably Achievable) program implementation, dosimetry and protective clothing use, radiation surveys, and compliance with radiation work permit requirements.

The inspector observed the February 3 and March 3, 1994, containment entries to add oil to the 'D' reactor coolant pump motor. The inspector noted that the pre-job brief was very detailed and comprehensive. The licensee used photographic documents to ensure personnel were aware of their surroundings and applicable dose rates. To ensure personnel familiarity with these monthly entries, and to maintain personnel dose ALARA, maintenance personnel are rotated to perform the evolution with one new and one experienced individual. The inspector reviewed the exposure received to date for each entry and noted that total accumulated dose has been decreasing with successive entries.

The inspector concluded that the strong radiation protection management involvement in the pre-job planning and post-job ALARA review has resulted in minimizing personnel exposure. The inspector determined that these activities were properly planned and well controlled.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (IP 40500, 90712, 92700)

6.1 Review of Written Reports

The inspector reviewed periodic reports, special reports, and licensee event reports (LERs) for root cause and safety significance determinations and adequacy of corrective action. The inspectors determined whether further information was required and verified that the reporting requirements of 10 CFR 50.73, station administrative and operating procedures, and technical specifications 6.6 and 6.9 had been met. The following reports and LER's were reviewed:

Unit 1 Monthly Operating Report for January 1994, dated February 14, 1994.
Unit 1 Monthly Operating Report for February 1994, dated March 14, 1994.
Unit 2 Monthly Operation Report for February 1994, dated March 14 , 1994.
Unit 3 Monthly Operating Report for January 1994, dated February 4, 1994.
Unit 3 Monthly Operating Report for February 1994, dated March 8, 1994.

The LERs noted with an asterisk reported conditions prohibited by license requirements. The inspectors determined that since the events were of minor safety significance, enforcement discretion per section VII.B of the NRC Enforcement Policy would be exercised and no violation would be issued.

* LER 50-245/94-04 reported that excessive leakage was detected through two Main Steam Isolation Valves during the performance of a Local Leak Rate Test.

LER 50-423/93-10 discussed inadequate testing of the reactor trip (P-4) input to the turbine trip interlock. This deficiency was discovered as part of the overlap task force review team as corrective action to LER 50-423/93-03. Overlap test deficiencies are being tracked under open inspection item URI 423/93-07-06.

* LER 50-423/93-15 discussed an improperly performed shutdown margin surveillance due to the use of an incorrect value for fuel burnup after refueling.

LER 50-423/93-17 reported the discovery of inadequate response time testing for the turbine trip (P-14) on high/high steam generator level. This deficiency was discovered as part of the overlap task force review team as corrective action to LER 50-423/93-03. Overlap test deficiencies are being tracked under URI 423/93-07-06.

LER 50-423/94-04 discussed a historical condition regarding the potential inoperability of the feedwater isolation valves. This event was discussed in NRC Inspection Report 50-423/94-01.

6.2 Review of Previously Identified Issues

6.2.1 Loss of Service Water Event - Unit 1 (VIO 245/91-04-01)

Inspection 50-245/91-04 describes an incident which occurred at Millstone Unit 1, on October 4, 1990, that resulted in the loss of service water and eventual collapse of the intake traveling screens, due to a high level of debris in the water. The event was caused by the removal, through the plant design change process, of a circulating water pump trip, which would have tripped the circulating water pumps when the differential pressure across the traveling screens reached 30 inches of water. The circulating water pump trip would have prevented the loss of service water function by restoring water level in the intake bays. Poor operator performance also contributed to the severity of the event in that the operators did not take the required manual actions to trip the plant. A violation was issued on July 8, 1991, concerning this event. Licensee corrective actions were specified in a written response dated August 28, 1991.

The immediate corrective actions were verified complete during NRC Inspection 50-245/91-04. During this inspection, the inspector reviewed the licensee's implementation of long term corrective actions. The results of this review are discussed below:

a. The licensee completed a design review to evaluate intake structure traveling screen performance during severe weather conditions with respect to debris removal methods and equipment. The inspector reviewed an undated licensee memorandum entitled, "Traveling Screen Corrective Action Summary" and also inspected the Unit 1 intake structure. The inspector noted that, of the nine recommended remedial actions, six have been completed (e.g. evaluation of basket strength, adequacy of traveling screen power transmission, installation of plexiglass viewing/trash removal ports in the spray housings). Most of the remaining actions deal with improving the debris removal efficiency of the traveling screen and screen wash systems. It should be noted, however, that removal of more debris from water without improving removal of the collected debris from the intake structure, via the debris sluiceway, would be counter productive. The inspector noted that the traveling screen and screen wash systems, as modified, have operated for several years, including under severe weather conditions, without significant problems. The inspector judged the design study, and implementation status, to be acceptable.

b. The licensee reviewed past Millstone Unit 1 design changes to ensure that any protective trip functions previously removed have no significant impact on plant safety or reliability. The licensee noted that 2400 modifications were reviewed and two previously removed protective trip functions were identified. One modification, associated with a condensate storage tank (CST) high level alarm, was subsequently reinstated. A second modification, removal of the main turbine high vibration trip, was considered to be justified because the logic was not redundant and a single spurious trip would result in a turbine trip. Implementation of the high vibration turbine trip varies across the industry. The inspector had no additional questions in this area.

c. The licensee's training department conducted an evaluation of the event. The inspector reviewed the final report, entitled "Investigation and Assessment of the Millstone Unit One Trip of October 14, 1990," OT1-91-024. The report concludes that, "The Training Department did not adversely contribute to this incident but can implement some techniques to help avoid such an incident in the future."

   The report suggested that a comprehensive treatment of the event be included in the operator requalification training cycle. The inspector reviewed exercise MP1-EOP-93-7-4, "Loss of Vacuum with an ATWS." This lesson plan and simulation capture many of the elements of the October 1990 event including: clogging and eventual collapse of traveling screens due to high wind and failure of two circulating pumps to trip on high differential pressure. Loss of service water and emergency service water due to post-screen-collapse clogging is also included in the exercise. Finally, an incomplete reactor scram, and ATWS, is included. The exercise provides students with practice on use of procedure ONP-514A, "Natural Occurrences;" ONP 507, "Loss of Vacuum;" and ONP 524D, "Loss of Service Water."

The report highlights the failure of the Shift Supervisor to maintain a supervisory "big picture" role in that he became involved in manipulating controls in an attempt to clear the clogged, traveling screens. The licensee has, more recently, recognized that operator work load is excessive, particularly during especially challenging simulator scenarios. Accordingly, the licensee has, for some time, been using an additional reactor operator on each shift to decrease work load and allow the Shift Supervisor to maintain his/her supervisory role.

During the event, operators deviated from established procedures at several important points in the event. The training department report recommended that operators receive advanced training in procedure use, similar to an SRO upgrade course. During the summer 1991, the licensee established an Advanced Requalification Training (ART) program that included an emphasis on procedural adherence. Six Unit 1 operators have completed ART training. More recently, the broader issue of procedural adherence at Millstone has been emphasized by the licensee's Performance Enhancement Program (PEP).

The training department report contains a good overview of the event and provides sound recommendations concerning areas that required reinforcement via improved training. The inspector found that the licensee's management was responsive to the principal recommendations of the report.

d. The licensee developed a common Conduct of Operations document addressing command and control expectations for all four of its nuclear plants. The inspector verified that a conduct of operations document has been issued for Millstone Units 1-3 and a separate conduct of operations document has been issued for the Haddam Neck Plant. These documents provide appropriate guidance to operators for the consistent performance of operational activities.

The inspector had no further questions regarding this event and considered this issue to be **closed**.

6.2.2 Untimely Processing of Plant Information Reports (VIO 245/91-16-01)

This issue involved a failure of the licensee to document and correct discrepant conditions in a timely manner. The specific corrective actions for the hydraulic control unit incident in question were reviewed in NRC inspection reports 50-245/91-16 and 92-25 and were found to be acceptable. However, the inspector left this violation open due to the licensee's continued failure to meet the intent of administrative control procedure ACP-QA-10.1 governing Plant Information Reports (PIRs), particularly prioritizing, evaluating and closing PIRs in a timely fashion and the poor procedure compliance example it represented.

Since that time, the licensee's PIR process has undergone a number of revisions, most particularly the recent emphasis on establishing a consistent, site-wide threshold for PIR generation which has resulted in a greatly expanded number of PIRs. The inspector's review of the PIR backlog noted that while progress was made in timely PIR closure since 1991, particularly at Unit 3, recent staff challenges coupled with the expanding number of PIRs has begun to swell the backlogs again. Conformance with the administrative requirements of procedure ACP-QA-10.1 appears to have improved, due to more visible PIR trending as well as increased management attention. A greater percentage of Phase I investigations were being completed in a few days as specified, and most PIRs received a formal extension, if needed, by the responsible Unit Director before they reached 90 days old. However, some administrative problems with PIR Phase I and II investigations were still noted, particularly at Unit 1 due to the competing staff demands from the ongoing outage. Furthermore, the inspector's original observations regarding the lack of prioritization and the large number of PIRs which go on to a time-consuming Phase II investigation remain. These deficiencies as well as other weaknesses in the program were noted in a Nuclear Safety Engineering Group (NSE) internal evaluation report issued on September 9, 1992. The corrective actions to address their findings have yet to be completed. One of the initiatives of the new Millstone management team is to develop a new, more responsive issues reporting process for the entire site. The licensee intends to implement the new process which replaces the PIR, in mid-1994. The inspectors are monitoring the progress of this initiative.

Given the initial corrective actions which addressed the specific technical problem noted, this violation is considered **closed**. Pending the completion of the long term corrective actions to resolve the aforementioned deficiencies observed in the PIR program, this inspection item will remain **unresolved**. **(URI 245/94-14-10)**

6.2.3 **Stuck Air Operated Pressure Control Valve - Unit 1 (URI 245/93-24-04)**

NRC Inspection Report 50-245/93-24 discussed the licensee's actions concerning the sluggish operation of reactor water cleanup pressure control valve 1-CU-10, which needs to operate from a remote panel in the event of a fire in the control room. While reviewing this issue, the inspector observed that the licensee did not periodically verify that the remote Appendix R shutdown panels, which are installed in various plant areas, function as required. In response to the inspector's concerns, the licensee committed to: (1) develop procedures to test the remote switches which are required by 10 CFR Appendix R during the next shutdown period; and, (2) include the special Appendix R requirements for some plant components in the plant technical requirements manual (TRM) by the end of the current refueling outage.

The inspector reviewed the draft TRM section entitled "Appendix R Safe Shutdown Requirements," as well as the licensee's commitment to test the remote switches. The draft TRM section included: (1) the Appendix R safe shutdown related (ARSR) components; (2) the operability requirements for ARSR equipment; (3) compensatory measures in the event of ARSR equipment inoperability; and, (4) surveillance requirements for ARSR equipment. ARSR equipment that is already included as part of the plant technical specifications was not included in the draft TRM section.

The inspector spot checked the equipment included in the draft TRM section against the equipment listed in the 10 CFR 50 Appendix R Compliance Review Report for Unit 1. The inspector did not find any examples of equipment which was not included in the TRM or referenced in the current technical specifications. Therefore, the inspector concluded that the TRM section, when issued, should ensure that Appendix R equipment is tested periodically and that compensatory measures will be taken if the equipment becomes inoperable.

The inspector also reviewed the licensee's commitment to develop procedures to test the remote switches. At the close of the report period, the licensee was still in the process of writing surveillance procedures for some of the equipment listed in the draft TRM section. However, thus far during the cycle 14 refueling outage, the licensee tested the remote switches for valve 1-CU-10, the main steam isolation valves, and the safety relief valves. No deficiencies were noted.

The inspector concluded that based on the information included in the draft TRM section and the engineering implementation of surveillance procedures to test the remaining remote panels, the licensee's corrective actions appear to be addressing the concerns outlined in NRC inspection report 50-245/93-24. This item remains **open** pending completion of the TRM revision and testing.

6.2.4 Technical Specification Action Statement Requirements - Unit 2 (URI 245/92-29-01)

During reviews of surveillance activities, the inspector noted that Unit 2 operators did not routinely enter the appropriate technical specification action statement (TSAS) when a technical specification (TS) surveillance rendered a safety system, subsystem or component incapable of performing its intended safety function. On February 24, the facility 2 (train B) containment spray (CS) system was rendered inoperable during the performance of operations surveillance procedure SP 2606B, "Containment Spray Pump Operability Test, Facility 2." The licensee did not enter TSAS 3.6.2.1, which requires two operable trains of CS. The licensee considered the CS system operable, as the procedure directed that a "dedicated operator" be stationed to restore the affected safety function in the event of an emergency.

The Unit 2 Conduct of Operations Procedure, OP 2276 (step 6.2.10), provides guidance for use of a "dedicated operator" to satisfy TS operability requirements. The procedure specifies certain criteria that must be included in each procedure allowing use of a dedicated operator, such as specific guidance for the dedicated operator. The licensee identified that procedure SP 2606B did not meet these requirements, declared the facility 2 CS system inoperable, and entered the appropriate TSAS. The CS system operability was restored in 25 minutes, and the allowed TSAS duration of 30 days was not exceeded. The inspector and the licensee identified a number of similar procedures which also did not meet the licensee's criteria for stationing a dedicated operator, for which the applicable TSAS was not routinely entered.

NRC guidance for using a dedicated operator to meet TS operability requirements, and for entering a TSAS when the system is unable to perform its intended safety function is contained in NRC Generic Letter (GL) 91-18, "Information To Licensees Regarding Two NRC Inspection Manual Sections On Resolution Of Degraded and Nonconforming Conditions and Operability." GL 91-18 states, in part, that if TS surveillances require safety equipment be removed from service and rendered incapable of performing their safety function, the equipment is inoperable. The LCO action statement shall be entered unless the TS explicitly directs otherwise. It also states that the assignment of a dedicated operator for manual action is not acceptable without written procedures and a full consideration of all pertinent differences. The apparent lack of understanding of the guidance provided in GL 91-18 previously was identified at Units 1 and 2, and documented as unresolved item **URI 245/92-29-01**.

The inspector was concerned that this long-standing issue could result in; exceeding TS allowed outage times for safety systems; rendering both trains of a safety system inoperable; and, the failure to implement compensatory actions required by TSs when a safety system function is inhibited. The inspector reviewed TS surveillances performed in 1993 where the equipment was unable to perform its intended safety function, and the TSAS was not entered, noting that allowed TSAS outage times were not exceeded. The inspector expressed his concerns to licensee management, prompting an evaluation of the apparent lack of understanding of GL 91-18 requirements. The licensee initiated Plant Information Report (PIR) 2-94-079 to determine causes and corrective actions.

On February 28, the Operations Manager issued night order 2/28/94-1, which directed licensed operators to enter the appropriate TSAS anytime a system is rendered incapable of performing its intended safety function, unless the requirements of procedure OP 2276 were met. Additional planned licensee corrective actions for Unit 2 include procedure revisions to incorporate GL 91-18 guidance, and training for operators on this issue. The inspector considered the licensee's planned corrective actions appropriate; however, the issue **remains open** pending an evaluation of the effectiveness of the licensee's corrective actions at Units 1 and 2, and a determination that the requirements of GL 91-18 are well understood and properly implemented across the station.

6.2.5 **Radiation Monitor Seismic Brackets - Unit 2 (VIO 336/93-19-05)**

This violation involved failure of instrumentation and controls (I&C) technicians to reinstall a seismic bracket in a spent fuel pool radiation monitor (RM) module as required by the instrument calibration procedure. This resulted in degradation of the seismic capability of the RM until the error was discovered by the licensee and corrected approximately two months later. The root cause evaluation results, corrective actions, and actions to prevent recurrence of the incident were documented in the licensee's response to the NRC Notice of Violation dated December 29, 1993. The root cause was determined to be personnel error/no self-checking, and the licensee disciplined the technicians involved and counseled the I&C staff regarding the need for attention to detail and strict procedure adherence. The inspector concluded that the corrective actions were adequate.

The licensee also identified a human factors weakness in the calibration procedure in that steps concerning the seismic bracket required multiple actions to be performed. The condition was corrected by adding to the calibration data sheet a verification signoff for reinstallation of the bracket. To prevent recurrence, the licensee reviewed the calibration procedures for other safety-related RMs and determined that no further changes were required. The inspector reviewed the calibration procedures for the seismically qualified containment particulate and gaseous RMs and noted that step 6.4.2 of both procedures did not specify removal of the bracket, while step 6.8.10, which contains multiple actions, required reinstallation of the bracket. The inspector discussed this finding with the I&C Department Manager and the appropriate procedure changes were initiated. The inspector concluded that the licensee's initial procedure review had been superficial, but that the subsequent changes acceptably addressed the seismic concern. This violation is **closed**.

7.0 MANAGEMENT MEETINGS

Periodic meetings were held with various managers to discuss the inspection findings during the inspection period. Following the inspection, an exit meeting was held on May 6, 1994, to discuss the inspection findings and observations with station management. Licensee comments concerning the issues in this report were documented in the applicable report section. No proprietary information was covered within the scope of the inspection. No written material regarding the inspection findings was given to the licensee during the inspection.