U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos.:	50-245	50-336	50-423
Report Nos.:	93-32	93-28	93-29
License Nos.:	DPR-21	DPR-65	NPF-49

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: November 17, 1993 - January 4, 1994

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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 82 hours during evening backshifts and 15 hours during deep backshifts.

Results: See Executive Summary

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EXECUTIVE SUMMARY

Millstone Nuclear Power Station

Combined Inspection 245/93-32; 336/93-28; 423/93-29

Plant Operations

Unit 1 operated at full power until December 3, when reactor power began to slowly decrease as the core reached the end of its fuel cycle. At the end of the report period, reactor power was at 93%; and the licensee was preparing for its cycle 14 refueling outage. Short power reductions were effectively performed for scheduled maintenance and testing. NRC review of equipment tagging performance revealed inconsistent levels of deficiency reporting for inadequate tagging events.

Unit 2 operated at full power for most of the report period. Reactor power was reduced to approximately 10% on November 20 for a planned maintenance outage, and full power operation resumed on November 22. NRC review of the reactor coolant system leak detection systems found that applicable procedures did not provide adequate acceptance criteria and direction. The mispositioning of valve 2-SI-637 contrary to the operating procedure, nearly resulted in the inoperability of both trains of high pressure safety injection. The licensee continued efforts to improve performance in the areas of procedural adherence and mispositioned valves. NRC noted some improvement in the severity of mispositioned valves, though the occurrence rate has not decreased.

Unit 3 experienced two power reductions during the report period: power was reduced to 98% from November 17 to December 21 due to spurious overtemperature-delta temperature and overpower-delta temperature runback alarms; from November 28 to December 1, the reactor was placed in mode 2 for repairs of a non-isolable steam leak from a main turbine steam line drain valve.

Maintenance

Generally, maintenance and testing were adequately implemented at each facility during this inspection period. However, poor procedure implementation was identified and corrected during the testing of the Unit 1 refuel machine load cell in preparation for fuel movement.

Unit 2 had several instances of inadequate procedures or procedure noncompliance for which overall corrective action was not adequate. Proper recalibration of condensate storage tank level instruments was not assured following modifications because procedures were not revised in a timely manner, and because one procedure was inadequate. Also, instrument technician qualification and training procedures were not strictly followed, potentially reducing the assurance of high quality maintenance and testing.

Engineering

Recent load studies of the Unit 1 electrical distribution system revealed a deficiency in the reliability of offsite power. With normal minimum switchyard voltage at the reserve station service transformer, a voltage drop due to full accident response loads may reduce bus voltage below the degraded grid relay setpoint and result in a loss of normal power shed signal. The licensee implemented generally good short term corrective actions and continues to evaluate long term solutions for this problem. The licensee also found and effectively corrected a violation of Unit 1 high energy line break controls.

The licensee was unable to locate several inservice inspection test records for leak tests performed during the 1990 Unit 2 refueling outage. The test results had not been recorded in the ISI summary report or submitted to the document control facility. The initial engineering assessment, which concluded that the affected systems were operable, did not provide the necessary detail to adequately assess the safety and regulatory significance of the lost records. A subsequent, more thorough assessment was acceptable. Supplemental leak tests of all accessible systems were completed and the licensee committed to perform leak tests of systems located inside containment during the first available plant shut down.

Unit 3 engineering conducted a generally strong engineering and technical evaluation of identified problems which resulted in spurious reactor trip/runback alarms caused by reactor coolant temperature fluctuations.

Safety Assessment/Quality Verification

Continuing procedure adherence and corrective action problems at the Millstone site contributed to many of the events and inspection findings reported during this period. Increased management and supervisory oversight was noted, as well as, a broad range of ongoing corrective actions addressing these issues, but the NRC was concerned about the apparent ineffectiveness of these actions thus far in reversing this trend.

A licensee event report concerning operation of the standby gas treatment system at Unit 1 exemplified a conservative approach to the reporting of plant design deficiencies. A weakness was noted in licensee review of a TMI Action Item involving operator access to certain plant areas following a design basis accident. Also, several Unit 1 licensee event reports were not submitted on time due to the apparent ineffectiveness of licensee corrective action for previous occurrences.

Unit 1 also reported the recent identification that the emergency diesel generator had been inoperable for a prolonged period in 1986. Since the root cause of this old event no longer applies to current EDG operability, no enforcement action was taken.

Licensee action regarding seven previously opened inspection findings was found to be acceptable to close those items. The licensee's program for reviewing industry operating experience was found generally to be effective. A recently revised program for incorporation of vendor information into plant procedures will be subject to future NRC inspection.

Enforcement discretion was exercised for licensee identified violations regarding inadequate implementation of a plant design change at Unit 3 and plant housekeeping at Unit 2.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 entered the report period at 100 percent power. Routine power reductions were conducted during the report period to support testing of the turbine stop valves and main steam isolation valves. During December, power reductions of up to 200 megawatts electrical were also performed at various times as requested by the load dispatcher to support work on the offsite electrical grid. On December 3, until the end of the report period, reactor power began to decrease as the core reached the end of the fuel cycle. A plant shutdown for refueling was scheduled for January 15, 1994. To maximize power output, the licensee adjusted the thermal efficiency of the reactor plant. The methods utilized included increasing the reactor water level program band from 30 to 35 inches to improve jet pump efficiency and decreasing the inlet feedwater temperature to improve thermal utilization. At the end of the report period reactor power was at 93 percent.

Unit 2 entered the report period at 100 percent power. Routine power reductions to approximately 97 percent power were conducted when condenser waterboxes were sequentially removed from service for maintenance inspections and liner repairs. On November 20, power was reduced to approximately 10 percent and the turbine taken offline for a planned outage to troubleshoot and repair a faulty circuit card in the turbine electrohydraulic control (EHC) cabinet. Following successful repairs to the EHC circuitry, the unit was returned to full power operation on November 22. At the end of the report period reactor power was at 100 percent.

Unit 3 entered the report period at 100 percent power. On November 17, power was reduced to 98 percent due to spurious overtemperature-delta temperature (OTdT) and overpower-delta temperature (OPdT) runback alarms. On November 28, reactor power was reduced and the plant placed in mode 2 due to the identification of a nonisolable steam leak on a main turbine steam line drain valve. Repairs were performed and the unit returned to 98 percent power on December 1. Full power operation resumed on December 5 after the adjustment of the OTdT and OPdT runback settings. On December 21, power was reduced to 75 percent for a short period due to degraded environmental conditions at the intake structure caused by severe weather. At the end of the report period reactor power was at 100 percent.

2.0 PLANT OPERATIONS (IP 71707, 71710, 93702)

2.1 Operational Safety Verification (All Units)

The inspectors performed selective inspections of control room activities, 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 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 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 inspectors determined that these operational activities were adequately implemented. Specific observations are discussed in Section 2.2 to 2.8 below.

2.2 Swing Battery Charger Usage - Unit 1

Unit 1 has three battery chargers to supply power to the safety-related 125 volt DC busses 101-A and 101-B. Normally chargers 'A' and 'B' are in operation, and the 'C' charger is used as a spare "swing" charger. On December 21, 1993, the licensee identified that the output voltage on the 'B' battery charger was varying by four to six volts. The 'B' charger was removed from service and the spare 'C' charger was placed on line. Inspection of the 'B' charger revealed that the voltage fluctuations were caused by a failed relay. The plant remained in this configuration for approximately 46 hours until the 'B' charger was restored to an operable status. The 'B' charger voltage fluctuations were documented in a plant information report, which was initiated on December 22, 1993.

The 'B' and 'A' battery chargers receive power from buses 12E and 12F, respectively. The spare 'C' battery charger can only be powered from bus 12F. If off-site power is lost, buses 12E and 12F would be supplied by the gas turbine and diesel generator, respectively. The inspector noted that when the 'B' charger was out of service and both the 'A' and 'C' chargers were aligned to bus 12F, both chargers would have been lost, if a design basis accident occurred and the 12F failed to re-energize. The licensee had not recognized this condition as operationally limiting (e.g. entered a technical specification action statement).

The inspector noted that Chapter 8.3 of the Unit 1, Final Safety Analyses Report describes the safety-related 125V DC power supply/battery systems as consisting of two separate systems: each including a battery charger, battery and distribution system. Unit 1 Technical

Specification (TS) 3.9.B.5 states, in part, that from and after the date that one of the two 125 volt battery systems is made or found to be inoperable for any reason, reactor operation is permissible only during the succeeding 24 hours, or be in cold shutdown within the next 24 hours. When the 'C' and 'A' chargers were aligned to bus 12F, separate battery systems as described in the Unit 1 FSAR and plant TS were not maintained. The inspector informed the licensee that if the 'A' and 'C' chargers are aligned to bus 12F for greater than a 48 hour period when the 'B' charger is inoperable, a violation of TS 3.9.B.5 would exist and that entry into that TS action statement was appropriate. The inspector noted that the licensee restored the 'C' charger two hours before the action statement for TS 3.9.B.5 would have expired. Therefore, a TS violation did not occur. However, the inspector noted that the return of the battery charger before the action statement expired was not planned or controlled.

The inspector noted that when the licensee planned to remove the 'B' battery charger from service, engineering examined the appropriateness of sustained use of the 'C' charger. Two of the issues examined concerned a postulated failure of the diesel generator to start or failure of bus 12F following a design basis event. The engineering department concluded that if the diesel generator failed to start, operators could reenergize bus 12F using a cross tie from bus 12E. Station procedures are already in place for completing that cross tie. If a loss of bus 12F occurred, the engineering department concluded that jumpers could be prepared to supply the 'C' charger from bus 12E. The engineering staff recommended that procedures should be developed for this contingency. These conclusions were documented in a December 21, 1993, engineering department memorandum to the operations manager.

However, the contingency procedures, which were outlined in the memorandum, had not been developed prior to the extended use of the 'C' battery charger. This is inconsistent to the guidance contained in NRC Generic Letter 91-18, "Guidance to Operators on Nonconforming Conditions and Operability," which states that if manual action is to be used in place of automatic functions, procedures should be in place before the manual actions are credited. Personnel in the electrical department informed the inspector that installation of the jumper assemblies to the 'C' charger would require engineering guidance. At the close of the report period, the procedures had not been prepared.

The inspector also determined that the licensee intends to replace the battery chargers during the 1996 refuel outage. As part of that modification, the licensee will evaluate the need to make the 'C' charger capable of being powered from both emergency power sources. In the interim, the licensee committed to revising procedures to reflect the operational limitations on the 'C' charger prior to startup from the impending refueling outage.

2.3 Review of Tagging Issues - Unit 1

During a licensee presentation on December 21, 1993, the inspector noted that licensee trending programs had identified a number of system tagging errors at the Millstone site. The plant information report (PIR) and work observation processes are two information systems which unit management utilizes to assess the adequacy of unit tagging performance. The inspector reviewed PIRs and work observation reports which had been prepared from July 1992 to January 4, 1994 to determine if the Unit 1 tagging program is being effectively implemented such that there is adequate equipment isolation prior to the performance of work activities.

Since July 1992, only one PIR documented the improper performance of a tagout evolution at Unit 1. The issue, concerned a February 1993 event involving improper tagout of the number two house heating boiler, which was documented in PIR 1-93-18. A review of tagging issues that have been documented under the work observation program revealed two events in which inadequate equipment isolation was established for the work activity. Based upon the review of these management information systems, it appeared that the Unit 1 tagging program is generally effective with isolated exceptions.

During discussions with plant personnel, the inspector became aware that Unit 1 personnel do not enter all inadequate tagging events into one of the two established information systems for assessment and tracking. For example, during the July 1993 period, while electricians were investigating a defective overhead light circuit in the intake structure, electrical sparking occurred. When the electricians tried to isolate the light circuit by operating the switch that had been blue tagged for the work activity, the sparking did not stop. The electricians later determined that the sparking was caused by a frayed wire in the lighting circuit, which had intermittently contacted the lighting fixture when the light was moved. The electricians informed their supervisor of the inability to isolate the light, and the lighting circuit prints were checked. Investigation revealed that the incorrect lighting switch had been tagged because of inadequate component labelling and tagout preparation. The maintenance manager stated that he did not initiate a PIR to document this event because the tagout was corrected, personnel in the operations department were informed of the issue, and the manager believed the event had minor safety significance. The equipment tagging procedure (ACP-QA-2.06A) requires appropriate circuit/system isolation to protect plant personnel and equipment. However, this event had no nuclear safety significance. This self-disclosing failure to provide adequate circuit isolation represented poor performance related to accurate verification of tagging activities. Based on the licensee-identified trend in this area, further review by Unit 1 management is appropriate.

Administrative Control Procedure (ACP) 10.01, "Plant Information Reports" states that a PIR should be initiated when an event occurs that warrants management attention. The inspector concluded that since the Unit 1 management information systems specifically track the number of tagging events that occur at the unit, events involving inadequate isolation should be documented. Not doing so denies management a means to assess the need for corrective action to prevent recurrence such as retraining of the individual who produced the incorrect tagout or discussing the event with other shop personnel to ensure they do not make a similar error. The inspector discussed this issue with the Unit Director who noted the inspector's comments. The Director stated this issue would be discussed with Unit 1 personnel as an example of when a PIR should be initiated.

The inspector reviewed PIRs that have been prepared at Unit 3 and noted that several PIRs had been prepared to document tagging errors on nonsafety-related or out-of-service spare equipment. For example, PIRs were written for tags being placed on incorrect spare breakers, circulating water pump components, and work which had improperly occurred in a warehouse. The inspector concluded that the information management system data for Unit 3 may be more valid than the data for Unit 1. Therefore the management information systems at Unit 3 are a better overall indicator of plant tagging performance than the system at Unit 1.

2.4 Motor Operated Valve Design Deficiency - Unit 1

On December 4, 1993, the licensee determined that, based upon test results that were performed by an offsite organization, certain motor operated valves at Unit 1 may not be able to perform their design functions under all accident conditions. The valves of concern, 1-CU-2 and 1-CU-3, are drywell isolation valves located in the reactor water cleanup (RWCU) system. The specific concern involved whether the valves would generate sufficient thrust to isolate a downstream pipe break based upon the current torque switch settings. Accordingly, the valves were closed and the RWCU system was removed from service. The NRC operations officer was notified of the valve design deficiency per 10 CFR 50.72(b)(2)(iii)(D) as a condition that alone could have prevented the mitigation of an accident.

To restore the valves to an operable status, the licensee modified the closing circuits of both valves. The modifications involved removing the torque switch trip from the valve closing circuit until the valve closed limit switch is energized. Once the closed limit switch has been energized, the torque switch is placed back into the valve closing circuit. The valve movement is then stopped by the torque switch when the valve torque reaches a preset limit. This modification was based upon a determination by the licensee that the stall motor torque values are sufficient to close the valves under design conditions without exceeding the structural capability of the valves.

In lieu of post-modification motor-operated valve static testing, the licensee cycled the valves and measured the valve actuator motor running and trip currents before and after implementing the modification. The licensee verified that the motor running and trip currents were essentially identical. These test results insured the valve stroke had not been changed by the modification. Once the post-modification testing was completed, the valves were opened and the RWCU system was restored to service.

The licensees's actions to address the valve design deficiency were reviewed by NRC Region I and Office of Nuclear Reactor Regulation personnel during a conference call. The NRC determined that the modifications were acceptable. The licensee is currently evaluating long term corrective actions, which are scheduled to be implemented during the January - March refueling outage.

2.5 Reactor Coolant System Leak Detection - Unit 2 (VIO 336/93-28-01)

In late 1993, the licensee shut down Unit 2 due to excessive reactor coolant system leakage from a manual letdown system isolation valve located inside the containment building. Based on observations of the lack of containment atmosphere process radiation monitor (RM) response, the inspector questioned the effectiveness of the system as an RCS leak detection method. General Design Criterion 30 of 10 CFR 50, Appendix A, requires, in part, that means be provided for detecting RCS leakage. Millstone 2 Final Safety Analysis Report (FSAR), Section 4.5.5, states that RCS leakage may be detected by one or a combination of instruments including containment airborne radioactivity monitors; containment sump level; containment pressure, temperature, and humidity; and differential temperature across the containment air recirculation system coolers. The function of these systems is to provide a timely warning to operators so that corrective action can be taken before the leakage rate exceeds acceptable limits. The unidentified RCS leakage limits of Technical Specification 3.4.6.2 is one gallon per minute (gpm) in operating modes one through four. The leakage rate must be reduced to within the limit within four hours, or the plant must be placed in the cold shutdown condition within the next 36 hours. Technical Specification surveillance requirement 4.4.6.2 verifies that RCS leakage is within acceptable limits by monitoring containment atmosphere particulate radioactivity and sump level every 12 hours and performing an RCS water inventory balance every 72 hours during steady state operation. Technical Specification 3.4.6.1 requires a containment atmosphere particulate RM, a containment atmosphere gaseous RM, and a containment sump level instrument to be operable in modes one through four. The technical specification basis and section 4.5 of the Millstone 2 Safety Evaluation Report state that the RCS leakage detection systems are consistent with the recommendations of NRC Regulatory Guide (RG) 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," which describes methods of implementing the requirement of General Design Criterion 30 which are acceptable to the NRC Staff. The inspector reviewed licensee procedures and the functional capabilities of the containment radiation monitoring system to assess licensee conformance to the requirements of RG 1.45.

Containment atmosphere particulate and gaseous radioactivity concentrations are monitored by channels 'A' and 'B', respectively, of RM-8123 and RM-8262. Samples are drawn from the containment air recirculation system ducts and directed to the monitors located in the enclosure building. Indication of radioactivity level, calibrated in counts per minute (cpm) is provided locally on panel RC-14 in the control room, trended on recorders and the plant process computer, and fed to a common process radiation monitor alarm annunciator on the main control board. Signals also are sent to the engineered safety features actuation system (ESFAS), which initiate main control board alarms and close the containment purge system isolation dampers on high containment radioactivity. The setpoint for these ESFAS functions is 70,000 cpm, based on minimizing off-site radiological dose rates following a design basis fuel handling accident.

Surveillance procedures SP-2619A-1, "Control Room Daily Surveillance, Modes 1 and 2," and SP-2619A-2, "Control Room Daily Surveillance, Modes 3 and 4," require containment atmosphere radioactivity levels to be logged every eight hours, and are intended to satisfy the requirement of TS 4.4.6.2.a that RCS leakage is less than one gpm. The inspector noted that the procedure acceptance criterion is "operable," and that no quantitative guidance is provided to convert cpm to units of flow. Though recognizing that information from RMs may not be precisely convertible to units of flow, RG 1.45 states that approximate relationships should be formulated, and Regulatory Position C.7 requires that procedures for converting various indications to a common leakage equivalent should be available to operators. The inspector questioned the licensee regarding the conversion of RM readouts in a memorandum dated October 15, 1993. In memorandum RB-93-515, dated November 18, 1993, the licensee expressed the concern that such guidance could lead to inappropriate operator action and that there were no current plans to develop the information. (Both memoranda are included as Attachment A & B to this report.) The inspector concluded that the licensee's position was inconsistent with its commitment to implement the RG. In addition, failure to provide adequate quantitative acceptance criteria for a surveillance test required by TS is a violation of 10 CFR 50, Appendix B, Criterion V which states, in part, that instructions, procedures, and drawings affecting quality shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. The inspector considered that the safety significance of this condition is mitigated by the availability of other diverse means of detecting RCS leakage. However, the lack of a questioning attitude by the operations staff which allowed this deficiency to exist for many years was a significant performance weakness.

The inspector also reviewed the main control board alarm annunciator response form associated with the containment atmosphere RMs. The form directs the operator to procedure OP-2383A, "Process Radiation Monitors Operation," which requires the alarming RM to be placed in "Alarm Defeat" to clear the common annunciator for subsequent alarms, and refers, in turn, to procedure OP-2314B, "Containment and Enclosure Building Purge," which instructs the operator to determine the cause of the increased radioactivity level and to verify that containment purge is secured and that the purge isolation dampers are shut. The inspector noted that the latter instruction is not applicable in modes 1 through 4 when TS 3.6.3.2 requires the containment purge dampers to be locked shut and deenergized. In addition, the procedures do not reference abnormal operating procedure AOP-2568, "Reactor Coolant System Leak." Finally, the containment atmosphere RMs are not listed as an entry condition to the AOP. Regulatory Position C.7 of RG 1.45 requires that indicators and alarms for each leakage detection system should be provided in the main control room, and that procedures for converting various indications to a common leakage equivalent should be available to the operators. The inspector concluded that the operating procedures were inadequate in that no method of converting RM indications to an RCS leakage equivalent were provided, and the leak detection function of the RMs was not addressed in these procedures. The inspector discussed this finding with the licensee, who revised the procedures to address the leakage detection function of the RMs. Licensee failure to provide adequate containment RM alarm response guidance was a violation of 10 CFR 50, Appendix B, Criterion V, which requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances. Through discussions with operators, the inspector concluded that, notwithstanding the absence of specific procedural direction, the general alarm response direction to determine the cause of the alarm would likely have led the operators to consult other available instruments to verify the existence of RCS leakage inside the containment building. Thus the safety significance of the deficiency was mitigated by operator knowledge and training. Nonetheless, the existence of the deficiency for many years is significant. The licensee's failure to provide adequate procedures to convert containment radiation monitor alarms and surveillances into an appropriate RCS leak rate response is a **violation** of 10 CFR 50, Appendix B **(VIO 336/93-28-01)**.

2.6 Sensitivity of Containment Radiation Monitors - Unit 2 (IFI 336/93-28-02)

Regulatory Position C.5 of RG 1.45 requires that the system response time of leakage detection systems be adequate to detect an RCS leakage rate of one gpm within one hour. Response time is important as it effects the operator's ability to initiate an investigation and take timely corrective action to minimize the potential for gross RCS boundary failure. The response time of the containment atmosphere RMs is dependent, in large part, on the radionuclide concentration of the reactor coolant. The RG acknowledges that RMs may be of limited value for early warning of very small leaks until activated corrosion products and fission products from fuel defects accumulate in the coolant after plant startup. The RG requires licensees when analyzing the sensitivity of the RMs to assume realistic RCS radioactivity concentrations and states that the values used in the plant environmental report are acceptable to the NRC Staff. Over the years, improved quality of reactor fuel assemblies and licensee cleanup initiatives have greatly reduced the normal concentrations of activated materials in the RCS. Noting that the current containment atmosphere alarm setpoint (70,000 cpm) was based on mitigating a fuel handling accident, the inspector requested the licensee to calculate the time required to actuate the alarm at a one gpm leakage rate assuming the RCS radioactivity concentration in the plant environmental report (18.1 microcuries per cubic centimeter - uc/cc) and the current, normal concentration (0.13 uc/cc). The results of the licensee's simplified calculation for the containment atmosphere gaseous RM are shown below:

Concentration	Alarm Setpoint	Time To Alarm
18.1 uc/cc	70,000 cpm	35 hours
0.13 uc/cc	70,000 cpm	No alarm

18.1 uc/cc	2.0 X Normal cpm	28 minutes
0.13 uc/cc	2.0 X Normal cpm	78 hours

The licensee stated that given the uncertainties involved, a simplified calculation of airborne particulate RM response was not practical. However, the licensee noted from experience that these RMs were more sensitive to changing radiological conditions in the containment. Based on observations of RM response during the operational event at Unit 2 in August 1993, the inspector confirmed that the particulate RMs responded more readily to the existence of RCS leakage.

The inspector concluded that the containment atmosphere RMs were capable of detecting a one gpm RCS leakage rate within one hour given the RCS radioactivity concentration assumed in the plant environmental report, and that the system met the design sensitivity requirement stated in the FSAR. However, the inspector also concluded that the nonconservative RM alarm setpoint severely compromised the ability of the system to function as an early warning to operators of RCS leakage in the containment building. In mid-December 1993, the licensee implemented procedure changes to provide lower alarm setpoints based on normal reactor coolant radioactivity concentration. The inspector considered this corrective action to be appropriate. The inspector also concluded that the RCS radioactivity concentrations assumed in the plant environmental report were no longer a realistic measure of normal RCS radioactivity and questioned with the NRC Office of Nuclear Reactor Regulation their use as a standard for evaluating the response time of the RMs as RCS leakage detection monitors. This is an open item pending completion of the NRC evaluation **(IFI 336/93-28-02)**.

2.7 High Pressure Safety Injection System Degraded - Unit 2 (VIO 336/93-28-03)

On December 2, 1993, the licensee notified the NRC in accordance with 10 CFR 50.72(b)(ii)(B) that both trains of high pressure safety injection (HPSI) had been inoperable for approximately 8 hours on November 16, 1993. Safety injection valve 2-SI-637 was found out of position by a plant equipment operator (PEO) on December 2, 1993 during the performance of a monthly surveillance. Since this valve is one of four injection throttle valves (2" motor operated valves) in the 'A' HPSI train set to maintain technical specification flow limits, the train was declared inoperable by operations staff. The valve was last verified to be in the correct position on or about November 10. Since that time, the opposite train emergency diesel generator (EDG) was taken out of service for approximately 8 hours during preventive maintenance. Since the 'B' EDG is the alternate source of power for the 'B' HPSI train, and technical specification 3.0.5 requires all redundant trains and subsystems of the alternate power supply to be operable, the licensee concluded that both trains of HPSI had been inoperable during the time that valve 2-SI-637 was mispositioned and the 'B' EDG was out of service.

Upon discovery of valve 2-SI-637 out of the required throttled position, the licensee entered a 72-hour technical specification (TS) action statement 3.5.2.c, which requires two independent, operable emergency core cooling system (ECCS) trains, including operable HPSI injection flowpaths. Operations performed surveillance procedure SP 2604E-3 to reposition valve 2-SI-637, and logged out of the action statement. The licensee documented the event under plant information report (PIR) 2-93-337, and initiated an analysis to determine the impact of the incorrect throttled position of valve 2-SI-637 on the HPSI system's ability to satisfy applicable TS and Final Safety Analysis Report (FSAR) requirements.

The engineering analysis compared the as-found position of valve 2-SI-637 to the required throttle position, calculating the reduction in flow (155 gallons per minute (gpm) vs. 176 gpm) through the associated injection header. HPSI system flows were then recalculated using the reduced flow value for the affected injection header, and compared to the HPSI system flows required by TS and FSAR accident analyses. The results demonstrated that neither the TS nor the FSAR safety analysis requirements had been violated, and the 'A' HPSI train had always been capable of satisfying its design safety function during the time that valve 2-SI-637 was mispositioned. On December 16, the licensee retracted the notification made in accordance with 10 CFR 50.72(b)(ii)(B).

The safety consequence of having valve 2-SI-637 throttled closed approximately 1/10 (39 degrees) of a turn from its required position was relatively low, as the licensee's calculations show that minimum TS and FSAR safety analysis flows were met. However, twice that error would have resulted in both HPSI trains being inoperable for approximately 8 hours.

A similar HPSI injection throttle valve (2-SI-647) was mispositioned on February 17, 1993. The event is documented in Millstone Inspection Report 50-336/93-03, Section 4.3. Valve 2-SI-647 is also in the 'A' HPSI train and performs the same function as valve 2-SI-637. The valve was mispositioned while the 'B' EDG was out of service for PMs, and both trains of HPSI were out of service for approximately 86 minutes. The licensee was cited for the inadequate procedures which contributed to the mispositioning of the valve, and resulted in the inoperability of the 'A' HPSI train. Corrective actions included upgrading surveillance procedure SP 2604E to manually position the throttle valves with the aid of a positioning tool and a diagram. The inspector reviewed the revised surveillance procedure and found it adequate. However, the inspector noted the licensee's corrective action did not prevent the December 2, 1993 event. The valve was manually positioned to its throttled position by a PEO using the revised surveillance procedure SP 2604E. The inspector concluded that proper use of the positioning tool and the diagram provided in the procedure should have assured the valve was throttled to its correct position. The failure of the PEO to correctly position valve 2-SI-637 is a **violation** of station procedures and TS 6.8.1 **(VIO 336/93-28-03)**.

2.8 Procedure Adherence and Mispositioned Valves - Unit 2

The inspector evaluated the licensee's past performance in the areas of procedure adherence, and mispositioning of valves. The evaluation included reviews of past PIRs and NRC inspection reports. Procedural adherence is well documented as a longstanding problem at Unit 2 (SALP report 50-336/92-99, Inspection Reports 50-336/93-06, 93-11, and 93-19). In a letter to the NRC dated December 29, 1993, the licensee documented initiatives to address procedural adherence deficiencies at Millstone Station: the STAR Program (stop, think, act, review) for continual self-checking; a procedure upgrade project to provide more user-friendly procedures; the inclusion of procedural adherence problems in the PIR program for tracking/trending; the work observation program to provide monitoring and feedback on procedural adherence and other performance issues; and, a monthly trend report issued by the Quality Assurance and Services (QAS) department which includes analysis and evaluation of several areas encompassing procedural adherence. Notwithstanding the aforementioned initiatives, the inspector has not noted significant discernible improvement at Unit 2 in this area through this inspection period.

Mispositioned valves are also a recurring problem at Unit 2. In August 1993, the licensee recognized the need for increased control of valve positions, and developed Operations Department Instruction 2-OPS-6.21, "Maintaining Valve Position Valve Control." The instruction introduced valve manipulation forms (VMF) as a means to document changes in valve positions when not controlled by valve lineups or tagouts. The new instruction and increased management attention in this area resulted in an initial increase of reported mispositioned valves since August 1993. Of approximately 29 events in 1993, 16 of them occurred after August. Although mispositioned valves continue to be found at a significant rate (8 mispositioned valves reported during this inspection period), there has been a reduction in the number of valve misalignments that have compromised the safety-related function of equipment: from 6 events in the first 8 months of 1993 (PIRs 93-057, 93-060, 93-088, 93-163, 93-170, and 93-178), to one significant event since August (PIR 93-312). The inspector noted that the majority of mispositioned valves are due to personnel error.

Though past mispositioned valve events have resulted in little or no safety consequence, they are indicative of inattention to detail and poor personnel performance that has not to date been isolated to nonsafety-related functions. Notwithstanding licensee initiatives and stated high standards of personal accountability, considerable management attention is required in the areas of procedural adherence and configuration control to preclude a future, more significant event.

2.9 Plant Trip - Unit 3

On November 28, 1993, with the plant at 98 percent power, the licensee identified a non-isolable steam leak on a one inch turbine plant drain valve and rapidly reduced power in accordance with abnormal operating procedure (AOP) 3575, "Rapid Downpower," to allow repairs. As required by AOP 3575, the moisture separator reheaters (MSRs) were removed from service. Soon after removing steam from the MSRs, the 'B' MSR pressure dropped to subatmospheric pressure and the condenser vacuum started to decrease. As condenser vacuum continued to decrease (with the plant at 17 percent power) the operators manually tripped the turbine. As required by operating procedure (OP) 3316A, "Main Steam," plant operators transferred all four steam generator atmospheric relief valves (ARVs) from automatic to manual control, in preparation for lowering the ARV control setpoint to reduce reactor coolant temperature closer to normal no-load temperature. However, the secondary plant operator was distracted from completion of the setpoint changes by feed system manipulations and communications regarding the MSR leak. Within fifteen minutes of tripping the turbine and placing the steam generator ARVs in manual, a steam generator safety valve lifted. The steam generator ARVs were opened approximately eight minutes later, after the setpoints had been readjusted and the valves were placed back in automatic control. The steam generator safety valve indicated closed approximately fifteen minutes after opening.

In response to the event, the licensee conducted an event investigation to identify the cause of the turbine trip and to evaluate overall plant response. The team identified that at least one leaking manway existed on the 'B' MSR at the time of the turbine trip. The manway is of such design that it seals with pressure and relaxes under vacuum if not properly torqued. Once the MSR depressurized, air leaked from the atmosphere into the MSR and then into the condenser which caused a rise in condenser pressure.

The team reviewed the sequence of events report and debriefed plant operators. They identified that within a few minutes of the turbine trip, reactor power was less than one percent and that the nuclear instrumentation had indicated a negative startup rate. At this time there were no steam dumps in operation due to low condenser vacuum, but the 'A' turbine driven feed water pump was in service. As expected, the steam demand from this source was sufficient to cause the average reactor coolant temperature to decrease. The senior control operator had directed the reactor operator to maintain reactor power between 2 - 5 percent (which is within the capacity of the steam generator ARVs). The reactor operator withdrew control rods to increase temperature and restore reactor power. This resulted in an increase in reactor coolant temperature because there was no corresponding increase in steam demand due to the manual control setting of the ARVs. The temperature increase resulted in steam generator pressure increasing to the first steam generator safety valve lift point. Had the steam generator ARVs been in automatic, they would have automatically opened due to the increase in steam generator pressure prior to reaching the steam generator safety valve lift setpoint.

The inspector reviewed procedure OP 3316A and identified that the steam generator ARVs are placed in manual prior to adjusting the setpoint to prevent the ARVs from opening rapidly, causing a steam pressure transient on one steam line which may be sensed as a steam line break and result in a spurious safety injection signal. The procedure doesn't provide any guidance regarding the number of reliefs to be placed in manual at a time. As corrective action to prevent challenging the steam generator safety valves, the licensee committed to revise procedure OP 3316A to specify that the steam generator ARVs should be placed in manual one at a time when adjusting the relief setpoint.

The inspector reviewed the sequence of events report and interviewed some of the operators who were on shift and concluded that overall operator response to the event was good. However, the event identified the operators lack of sensitivity to the effect of placing the ARVs in manual and inadequate operator control and oversight of steam generator pressure. The corrective action to modify procedure OP 3316A to limit the number of ARVs in manual should ensure that some steam generator ARVs remain available to prevent challenging the main steam safety valves.

The inspector reviewed the maintenance history for the MSRs and identified that they had been worked during the refueling outage (July 1993 - November 1993) and that there was an outstanding work order to tighten down on the manways. The work order specified that the work was to be performed when the plant reached 100 percent power. The inspector questioned the licensee on why the manway had not been tightened and was informed that due to a communications problem, the work order was overlooked. The work order was in a pile of post outage work orders that had been generated for various pieces of equipment in the event that leaks developed. These work orders had not been reviewed subsequent to the start up to determine that no work was required and the work orders could be closed. The inspector questioned the licensee on whether the work order had been listed on the work overdue list or the backlog list and was informed that it had not. The inspector was informed that since the work frequency was not input into the production maintenance management system that the work order would not default onto either of these lists. The inspector was informed by the licensee that the phase two investigation of the turbine trip event will include a review of this area to determine what corrective actions are necessary.

2.10 Engineered Safety Features Walkdown - Unit 3

The inspector performed a detailed review of the Unit 3 supplemental leak collection and release (SLCR) system during this inspection period. 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 SLCR system is designed to work in conjunction with the auxiliary building filter (ABF) system to maintain the secondary containment boundary under a negative pressure to ensure that any containment leakage occurring during loss of coolant accident conditions into the enclosure building will be filtered through high efficiency particulate air filters and charcoal absorbers prior to discharge to the atmosphere.

During the walkdown of the SLCR system, the inspector noted that manual dampers 3HVR*DMP21, 27, 31, and 80 were not listed on valve lineup form OP 3314I-3 and that damper 3HVR*DMP30 was in the open position whereas the valve lineup form listed the damper position as being throttled. The inspector reviewed the latest air balance final lineup and verified that the above mentioned dampers were in their correct positions. The licensee also verified that the above dampers were in their correct position and have added the dampers to and corrected the listed positions on the valve lineup. As part of the plant information report investigation, the licensee committed to review other safety grade ventilation system lineups and attempt to determine the cause for the valve lineup discrepancies.

The inspector reviewed the following operational and surveillance procedures to verify that they adequately test the SLCR system in accordance with technical specification (TS) requirements.

- OP 3614I.1, SLCRS Operability Test
- OP 3614I.2, SLCRS Filter Bank Testing
- OP 3614I.3, SLCRS Negative Pressure Verification
- OP 3646A.17, Train A ESF with LOP Test
- OP 3646A.18, Train B ESF with LOP Test
- SP 3712F, SLCRS Filter Assembly Heater Surveillance Test

The inspector's review of the procedures and test data revealed that procedure OP 3614I.2 incorrectly listed the acceptance criteria for the inplace penetration and bypass leakage on operations forms OP 3614I.2-7 through -10 as less than or equal to 0.05 percent whereas TS surveillance requirement 4.6.6.1.b(1), 4.6.6.1.e, and 4.6.6.1.f specify less than 0.05 percent. In addition, operations forms OP 3614I.2-7 through -10 do not specify that these measurements are to be taken while operating the system at a flow rate of 7600 cfm to 9800 cfm as required by TS. The inspector notified the licensee of these discrepancies and was informed that they had already been identified and that the procedure was in the process of being revised. During the review of completed surveillances, the inspector identified that operating forms OP 3614I.1-1 dated October 15, 1993, and OP 3614I.1-2 dated November 4, 1993, had been accepted by the shift supervisor but had not been approved by the department head. Inspector review of the test data indicated that the tests were acceptable. The licensee immediately reviewed the test data and approved the surveillances when informed of the discrepancy.

In addition, as documented in NRC Inspection Report 50-423/93-24, the inspector concluded that the licensee's testing program does not adequately verify that components in the ABF system would perform as required in a design basis event. As a result of this finding the licensee committed to develop additional procedures as recommended by the SLCR/ABF event task force to address weaknesses in their surveillance test program. The adequacy of these procedures will be reviewed as part of the follow up to **unresolved item 423/93-24-03**.

The inspector concluded that, based on observation of the SLCR system surveillances, confirmatory testing performed during the 1993 refueling outage, and a walkdown of the system, that the SLCR system was operable. No discrepancies were noted which would degrade system performance.

3.0 MAINTENANCE (IP 62703, 61726)

The inspectors observed and reviewed selected portions of preventive and corrective maintenance activities and surveillance tests to verify adherence to regulations and administrative control procedures; conformance with 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 and testing activities:

- M2-93-14150, A LPSI pump suction pressure gage calibration.
- M2-93-14151, B LPSI pump suction pressure gage calibration.
- M2-92-18497, A LPSI pump annual preventive maintenance (mechanical).
- M2-93-14248, Troubleshooting of control room fan 22A.
- M3-93-27538, B EDG weekly PM
- M3-93-27607, 125 VDC Battery 301A-1 PM

Except as noted below, the inspectors determined that the maintenance and surveillance activities observed were performed adequately. Details of other inspector observations are provided below.

3.1 Reactor Water Cleanup System Isolation Valve Failure - Unit 1

On December 6, 1993, operators noted that valve 1-CU-5, a containment isolation valve in the reactor water cleanup (RWCU) system, developed dual indication when it was cycled. Valve 1-CU-5 is operated through use of a Teledyne motor-operated actuator and is located on the suction of the auxiliary RWCU pump. The valve is normally closed during plant operation. Licensee investigation revealed that the dual indication was caused by a position limit switch that was not rigidly mounted on the actuator body. The degraded mounting allowed the open position indication even though the valve was closed.

Once the limit switch was correctly mounted in the valve operator casing, the valve was cycled. However, the valve stroke time failed to meet the twenty second technical specification (TS) limit. Licensee investigation of the slow stroke time revealed that the electricians did not properly set the valve limit switch when the switch was reinstalled in the valve actuator. Specifically, the stroke time of valve 1-CU-5 is measured by the licensee based upon movement of the valve from a partially closed rather than full open position. The licensee changed the stroke, by limiting the valve movement in the open direction in

June of 1989 to ensure it would meet the TS stroke time requirements. When the valve limit switch was reset during the December 1993 troubleshooting, the electrician apparently set the open limit switch based upon a full open valve instead of throttled. The inspector noted that the licensee does not formally track the relationship between actual valve and limit switch position. Therefore, during valve maintenance activities, electricians will set the open limit switch based upon a fully open valve. If a valve requires a limited stroke, to meet TS required stroke times, electricians will be alerted to this fact only if the valve fails the TS required stroke test. The licensee is reviewing this issue as part of the investigation of the slow valve stroke time.

To ensure the limit switches of similar actuators were properly attached, other Teledyne actuators were examined. The inspector observed electricians inspect valves 1-LP-9A, 1-LP-43A and 1-LP-44A. No deficiencies were noted in the mounting of the limit switch brackets. The inspector noted that the dual indication and slow valve stroke time problems were documented by the initiation of separate plant information reports, which were in various phases of review at the end of the report period. Based upon the actions that the licensee had performed to date, the inspector concluded that the licensee was properly investigating the issues concerning valve 1-CU-5. No violations were identified.

3.2 Steam Tunnel Radiation Monitors Failure - Unit 1

On January 3, 1994, the licensee informed the NRC that both steam tunnel vent radiation monitors had been rendered inoperable during the performance of a surveillance test. Both steam tunnel vent radiation monitors are required by plant technical specification (TS) 3.2, Protective Instrumentation, to be operable. The monitors are designed to isolate the exhaust from the steam tunnel if a preset activity limit is reached. The out of service time period was short, approximately four minutes. However, during that time period, a system was out of service that would prevent the release of radioactive material from the main steam tunnel. Accordingly, the out of service condition of the monitors was reportable per 10 CFR 50.72 (b)(2)(iii), any event that alone could prevent the release of radioactive material.

The event occurred during the performance of a routine channel calibration of the monitors per instrumentation and controls (I&C) procedure SP 406W, "Steam Tunnel Ventilation Radiation Monitor Functional Test." During the performance of the channel check on the 'A' steam line monitor, the I&C technicians noted that the 'A' channel did not calibrate as required. The technicians informed their supervisor of the anomalous results and then reperformed the test. During the second performance of the test, the monitor performed acceptably. The technicians assumed that the first failure was due to an incorrect test setup. Consequently, the monitor was declared operable and placed back into service. The 'B' train monitor was then taken out of service and tested. After approximately four minutes, the testing was completed and the 'B' train monitor was declared operable. Later that day, while reviewing the surveillance test results, the I&C technicians decided to retest the 'A' train radiation monitor. When the monitor was tested, it again failed the channel check, was declared inoperable and the appropriate TS action statement was entered. Once the monitor failed the second surveillance, the licensee determined that it could not be assured that the monitor remained operable when it was restored to service earlier in the day. Accordingly, the licensee conservatively used the original surveillance test performance time as the start of the TS limiting condition for operation out of service time for the monitor.

Further troubleshooting of the monitor revealed that a degraded amplifier may have been the cause. The amplifier was subsequently replaced by the licensee and the "A" train monitor was declared operable the following day. At the close of the report period, the licensee was investigating the cause of the amplifier failure.

The inspector reviewed the event and determined through interviews that the I&C technicians followed procedure SP 406W during the performance of the surveillance test. The inspector noted that there were no indications of an unmonitored radioactive release during the four minute time period that both monitors were out of service. The inspector noted that the technicians displayed a proper questioning attitude by rechecking the monitor's performance even though it had met the surveillance acceptance criteria. The additional examination uncovered an intermittent failure which may not have not been repeatable at a later time period. The inspector concluded that neither the intermittent failure of the 'A' train monitor nor the potential dual train outage constituted violations of NRC requirements.

3.3 Refuel Bridge Preoperational Testing - Unit 1 (IFI 245/93-32-04)

Testing of the refuel bridge interlocks prior to use of the bridge during refueling operations is required by Unit 1 Technical Specification (TS) 3.10, Refueling and Spent Fuel Handling. The inspector observed the testing of the refuel bridge load cell. This load cell provides indication of the loading on the fuel handling mast. The load cell will prevent upward movement of the refuel mast if it detects greater than expected loading.

Testing of the refuel bridge load cell is a two step process. First, the load cell response to simulated load signals is checked. The second test involves performing a functional test by lifting a fuel assembly and verifying that the load cell displays the weight of the assembly within plus or minus 50 pounds. The load cell testing is conducted by Instrumentation and Controls (I&C) technicians with the assistance of the operations department per I&C procedure 465, "Refueling Platform Load Switch Check Out and Calibration." The inspector observed the functional test of the load cell. The functional test was conducted concurrently with an operational test of the refuel mast. The refuel mast operational test involves lifting a dummy fuel assembly and verifying that the refuel mast can hold the assembly for ten minutes. The inspector noted that the functional test of the load cell (I&C procedure 465) could not be performed in conjunction with the operational test of the refuel mast because the load cell test requires an actual fuel assembly while the operational test uses the dummy assembly.

Specifically, a dummy fuel assembly was being lifted as part of the refuel mast operational check out procedure rather than an actual fuel assembly as required by I&C procedure 465. The load cell functional test portion of the surveillance test was stopped when the technician realized that the weight of the dummy assembly, approximately 400 pounds, appeared to be less than the expected weight of an actual fuel assembly, approximately 600 pounds. Apparently the technician assumed that the weight of the dummy and actual assemblies were identical. The inspector noted that if I&C procedure 465 was strictly followed, such an assumption could not occur. Specifically, I&C procedure 465 requires, as a prerequisite, that the weight of a fuel assembly be obtained prior to the lift of the assembly. The technician did not obtain the weight of either the dummy assembly or an actual assembly prior to initiating the test of the load cell. When the error became apparent, the refuel bridge load cell calibration was stopped, and an investigation was commenced. A first line supervisor had authorized the conduct of load cell responses to test signals separate from the load cell functional test. The procedure prerequisite requiring a fuel assembly weight to be obtained and logged was not completed at that time. When the technician later attempted to combine the load cell functional test with the refuel mast operational test, the procedure was not in hand nor did a co-worker read the appropriate steps (including prerequisites) which would have shown that the two tests were incompatible. The conduct of procedure 465 without satisfying the procedure prerequisites, and without the procedure in hand or read by a co-worker did not conform with the licensee expectations for compliance with continuous use procedures as detailed in procedure ACP-QA-3.02E, "Procedure Compliance." The inspector noted that the licensee subsequently obtained an accurate weight of a fuel assembly and performed a satisfactory functional test of the load cell. Since the technician quickly recognized the error and stopped the calibration attempt, obtained a correct weight of a fuel assembly and successfully performed the test, enforcement discretion will be used and no violation will be issued in accordance with section VII.B. of the enforcement policy. However, the inspector stressed to the licensee the importance of I&C personnel strictly conforming with management expectations for procedure adherence.

Once the test of the load switch was stopped, the inspector raised additional questions regarding the adequacy of the refuel bridge operational testing. Specifically, the inspector noted that the operational testing of the refuel mast that is performed with the dummy assembly does not adequately test of the load bearing characteristics of the refuel bridge since the dummy assembly weighs less than an actual fuel bundle. Also, raising an actual fuel bundle for the functional test prior to an adequate load bearing test is not consistent with the requirement for refuel bridge testing prior to fuel movement.

The licensee reviewed the refuel bridge surveillance testing and preventive maintenance procedures and industry crane testing standards. The licensee concluded that the current testing program is adequate to ensure crane operability per TS 3.10. However, other enhancements such as a full load test will be considered as a way to improve the overall reliability of the refuel bridge crane. These testing improvements would be evaluated before the next refuel outage, which is currently scheduled for 1996. No other observations were made by the inspector. Inspector follow item **(IFI 245/93-32-04)** will be opened to track completion of licensee actions to address this weakness.

3.4 Troubleshooting and Repair of the Turbine Control System - Unit 2

On October 20, 1993, without apparent cause, the "intercept valve fast close" indication was received at the Unit 2 turbine electrohydraulic control (EHC) cabinet. At the same time, the control room received an "EHC malfunction alarm." The licensee's investigation revealed that the intercept valves had not closed, and no other turbine EHC components had been affected. A computer printout of the sequence of event (SOE) points for contacts changing state during the event revealed similarities with an event that occurred on June 3, 1993. On June 3, the turbine intercept valves closed rapidly, causing the turbine generator to trip off line on rapid loss of load. The loss of the main turbine generator from 100 percent reactor power created a high pressure condition in the reactor coolant system, and the reactor tripped on high pressurizer pressure. The licensee's investigation subsequent to the June 3 event concluded that the cause for the intercept valve closure and subsequent turbine trip was a spurious signal, generated when the EHC cabinet doors were shut. The licensee noted that, historically, the EHC cabinet has been highly susceptible to vibration.

The licensee developed a troubleshooting plan to localize the cause of the EHC susceptibility. On November 2, following analysis by the licensee and the EHC vendor (General Electric), the licensee concluded the most likely cause of the fault was in the circuit card containing relay KT106, or associated wiring downstream of the relay. Based on the SOE computer points, EHC circuit contacts for the Load Control Unit, Load Control Unit Logic, Speed Control Unit, and Speed Control Logic all changed states during both events. These contacts are actuated by one of two KT106 relay contact sets (normally closed). The other (normally open) contact set for KT106 actuates the EHC master trip relay, which would cause an immediate turbine trip; however, the master trip relays did not actuate during either event. The troubleshooting plan required the EHC circuit card containing the KT106 relay to be replaced, and the wires downstream of the card to be agitated. However, the licensee and the vendor representative had less than a 50 percent confidence factor that this approach would resolve the problem. The licensee elected to continue monitoring the EHC cabinet 24 volt supply for approximately two weeks and reassess the problem after that.

During a meeting with the Unit Director on November 2, the inspector emphasized the significant challenge to reactor systems caused by EHC system failures and the need for vigorous pursuit of the cause of these anomalies. The Unit Director concurred with the inspector's position, and took prompt action to expedite troubleshooting and repair activities. Additional personnel were assigned to this activity, and a second vendor (Mechanical Dynamics and Analysis Inc.) was contracted. A more rigorous review of the EHC system circuitry confirmed the initial diagnosis, providing a much higher degree of confidence that the troubleshooting and repair would be successful.

On November 20, reactor power was reduced to approximately 10 percent for troubleshooting and repair of the EHC system, as well as to complete additional repairs on balance of plant (BOP) systems. During troubleshooting of the circuit card containing relay KT106, I&C specialists lightly tapped on the card with the back of a screwdriver. The light taps caused several contacts to trip, and the specialists verified through a computer printout of SOE points, that the EHC circuit contacts changed state in a similar sequence and time frame as the June and October events. This confirmed a fault in the circuit card containing relay KT106, and the specialists replaced the card.

The inspector observed portions of the EHC troubleshooting activities, and reviewed applicable documentation. The troubleshooting guide coordinated all activities performed in the EHC cabinet, and was reviewed and approved by station management. With the exception of a minor administrative deficiency identified by the inspector, the activities were performed in a safe and professional manner. The licensee completed all planned outage activities ahead of schedule, and resumed full power operations on November 22, 1993. The inspector had no concerns regarding the performance of troubleshooting and repair of the EHC cabinet.

3.5 Planned Outage - Unit 2

The licensee commenced a controlled reactor shutdown to approximately 10 percent power on Saturday, November 20, 1993. The outage was planned primarily for the troubleshooting and repair of the turbine electrohydraulic control (EHC) cabinet, with a scheduled duration of 62 hours. Additional work scheduled during the outage included repairs of the 'B' moisture separator reheater shell drain control valve outlet piping, the 1B feedwater heater shell vent valve (2-HD-57C), and other minor repairs of balance of plant (BOP) systems.

At approximately 80 percent power, the licensee cycled the 'A' steam dump valve controller in the automatic mode of operation to maintain required steam flow during testing of the main turbine control valves; however, the 'A' dump valve did not respond. The steam dump system is a non safety-related system designed to help prevent the steam generator code safety valves from lifting, which in turn provide overpressure protection for the steam generators and main steam piping. The licensee lowered reactor power to approximately 30 percent, which would allow testing of the main turbine control valves, but was low enough so that failure of the 'A' dump valve would not impact the ability of the steam dump system to handle a loss of load. Attempts to cycle the dump valve with the dump valve controller in the manual mode were unsuccessful. Instrumentation and Control (I&C) technicians determined the 'A' steam dump valve controller was receiving an input signal, but was failing to provide an output signal. Upon examining the controller, I&C technicians found a charred resistor. The dump valve controller was replaced and tested satisfactorily. The inspector concluded that the activities surrounding the troubleshooting of the 'A' steam dump controller were satisfactory.

The inspector evaluated the licensee's planning and scheduling activities for the outage. The outage schedule listed activities to be performed during specific time frames, identifying responsible individuals and all applicable automated work orders (AWOs) with their current status. Licensee management scrutinized each line item in the schedule on a daily basis during the week prior to the outage, considering the impact of each work activity on the plant and the outage schedule, and developing contingency plans. In addition, they developed a list of key discipline contacts for each shift during the outage. The inspector concluded the licensee's extensive preparations for the outage contributed to its success.

The inspector monitored selected outage activities during deep backshift inspections on Saturday, November 20. No deficiencies were noted. The licensee completed all scheduled activities and returned to 100 percent reactor power at approximately 4:00 a.m. on Monday, November 22, 10 hours ahead of schedule. The inspector noted this was a significant improvement over past planned outages, which have typically lasted longer than planned.

3.6 Condensate Storage Tank Modifications - Unit 2 (VIO 336/93-28-05)

During the cycle 11/12 refueling outage at Unit 2 (May 1992 to January 1993), the condensate storage tank (CST) was modified to ensure high quality makeup water to the new steam generators by providing a nitrogen blanket above the water to limit oxygen intrusion into the stored inventory. The modification was performed under plant design change record (PDCR) 2-079-92. A nitrogen pressure regulating system was installed to maintain a slightly positive pressure on the tank. Relief (breather) valves and rupture discs were installed to protect the tank from overpressurization or excessive vacuum. In order to compensate for the new operating conditions on the tank, the PDCR called for recalibration of the CST level instruments and readjustment of alarm settings. The inspector reviewed licensee activities with regard to the level instruments to assess the implementation of the modification. The inspection consisted of discussions with licensee personnel and review of PDCRs, automated work orders (AWOs), instrument calibration calculations and loop folders, and operating and instrumentation and controls (I&C) department procedures.

The CST provides normal secondary water makeup to the main condenser hotwell and, in an emergency, is the preferred source of steam generator makeup water to the auxiliary feedwater system. Technical Specification (TS) 3.7.1.3, requires a minimum volume of 150,000 gallons of water to be maintained in operating modes 1, 2, and 3 in order to assure that sufficient water is available to remove reactor decay heat and/or to cooldown the reactor coolant system after a reactor trip. Operating procedure OP-2319B, "Condensate Storage/Surge System," governs operation of the CST. Three level instruments are associated with the CST:

- L-5282 provides CST level indication on a control room recorder, and at the remote hot shutdown and fire shutdown panels. The recorder is used for periodic verification of minimum CST inventory as required by TS 4.7.1.3. High and low level alarms warn operators of potential tank overfill or the need to refill the tank.

- Switches associated with level transmitter L-5280 control a CST makeup valve and an alarm associated with the minimum TS inventory.

- L-5489 provides local CST level indication and a Low-Low level alarm in the control room to warn operators of impending loss of auxiliary feedwater pump net positive suction head.

PDCR 2-079-92, Revision 0, was signed off as complete by Unit 2 engineering, and the CST was released to the operations department by turnover memorandum EN2-93-011, on January 4, 1993. Administrative Control Procedure (ACP) ACP-QA-3.10, "Preparation, Review, and Disposition of Plant Design Change Records," contains detailed instructions for implementing plant design changes. Step 4.6.2 of the ACP states that operations procedures must typically be updated before the design change is declared operational, and step 4.14.5 requires the plant engineer to ensure that all other administrative items, including the procedures, specified on Form B of the ACP as being a requirement for declaring a system operational, are completed prior to system turnover. The inspector reviewed the administrative items listed on Form B of the PDCR and noted that Stone and Webster Engineering Corporation (SWEC) calculation 17272-02-ME(B)-004 was listed as the controlling document for recalibration of CST level instruments. Also, according to Form B, Revision 11 of procedure OP-2319B was to have become effective prior to turnover of the CST to the Operations Department.

The inspector reconstructed the sequence of events regarding the changes made to the CST level instruments relative to engineering release of the system to the Operations Department on January 4 and entry of the plant into mode 3 on January 7, 1993. Late in the refueling outage, the licensee determined that the SWEC calculation was inadequate. The licensee also decided to recalibrate the CST level instruments to a common zero reference point. The Plant Services Department (PSD) was requested to perform a new calibration/setpoint calculation to implement the changes. Final design inputs for the calculation were decided upon on December 30, 1992, one week prior to plant startup, and PSD calculation 90-032-293-E2, "MP2 Condensate Storage Tank (CST) Level Loop Accuracy L5280, L5282, L5489," was completed on January 8. The inspector found, however, that instruments L-5280 and L-5489 were recalibrated one week prior to completion of the new calculation. The inspector was unable to determine who provided I&C personnel with the information required to perform the adjustments. Revision 10 of procedure OP-2319B, which reflected the setpoints contained in the superseded SWEC calculation, was approved by the plant operations review committee (PORC) on January 8, the day after mode 3 was entered. (This revision was not referenced in the PDCR.) Instruments L-5282 and L-5489 were not recalibrated (and retested) to the values contained in the PSD calculation until February 12 and 15, respectively. However, the inspector found that Revision 11 of procedure OP-2319B, which was referenced in the PDCR and which contained the alarm settings of the PSD calculation, was approved by the PORC on February 5.

The inspector assessed the effect that the different alarm settings and instrument calibrations may have had on system operation from January to February, 1993, and concluded, with one exception, that operators would have had sufficient warning of reduced CST inventory prior to going below the TS minimum volume requirement. The exception involved the Low-Low level alarm associated with instrument L-5489, which would have alarmed nonconservatively by approximately 18% of tank level, delaying operator compensatory measures. The inspector concluded that the potential for loss of the auxiliary feedwater system pumps on low suction pressure under post-accident conditions was increased by the calibration error. The inspector considered this condition, which existed for two weeks, to have been safety significant.

Failure to recalibrate the CST level instruments and to update procedure OP-2319B prior to engineering release of the system to the Operations Department is a **violation** of 10 CFR 50, Appendix B, Criteria III and V, which require that measures be established and followed to ensure that the plant design basis is correctly translated into procedures and procedure ACP-QA-3.10, steps 4.6.2 and 4.14.5. **(VIO 336/93-28-05)** NRC enforcement action for similar violations of design control requirements during the 1992 refueling outage was documented in NRC Inspection Report 50-336/92-36. That violation was not cited based on the licensee's corrective actions, which included review of completed PDCRs. Since the condition discussed above was not identified or corrected by the licensee at that time, this NRC-identified violation will be cited.

On June 23, a revision to the PDCR was signed off as complete by the Engineering Department manager and approved by the PORC. The revision, in part, reflected a minor change to the operating characteristics of the CST under vacuum, which required Figure 8.1 of procedure OP-2319B to be revised. The figure shows pressure setpoint ranges for the CST nitrogen blanket. The PDCR revision also deleted reference to the superseded SWEC calculation and substituted a new revision of the PSD calculation. The revised calculation had minimal effect on the existing level instrument calibrations. The inspector reviewed the latest revision of procedure OP-2319B in the control room and identified that Figure 8.1 had not been revised according to the revised PDCR. Licensee action to prevent recurrence of the design control violation documented in NRC Inspection Report 50-336/92-36 was embodied in memoranda from the Vice President of Millstone Station dated February 2 and May 7, 1993. The memoranda required the engineering organizations to identify procedure changes to the PORC prior to release of affected systems to the operations department, and required the engineering manager to review PDCRs prior to the release to ensure that they are completed properly. The inspector concluded that the change to Figure 8.1 was not operationally significant. However, the inspector considered to be significant the apparent ineffectiveness of previous licensee corrective actions. Therefore, this second, NRC-identified example of the **violation** of 10 CFR 50, Appendix B, Criteria III and V, and of procedure ACP-QA-3.10 will be cited **(VIO 336/93-28-05)**.

3.7 Calibration of Condensate Storage Tank Level Instrument - Unit 2 (VIO 336/93-28-06)

In August 1993, the licensee performed another CST setpoint calculation at the request of the I&C Department to provide switch setpoint tolerances for instrument L-5280. On September 24, the switches associated with instrument L-5280 were reset per the August calculation. The adjustment was performed using procedure IC-2435B, a general balance-of-plant preventive maintenance procedure, which directs that instruments be calibrated per the technical information contained in instrument loop folders. The inspector reviewed the loop folder for level instrument L-5280. The loop folder contained I&C Department Form 3.02-1A, "Instrument Calibration Data Sheet," which provided settings for the TS low level alarm and the CST makeup solenoid valve switches, and a single-page manufacturer's service instruction.

The switch adjustment portion of the service instruction stated, in part, "rotate adjustment screw clockwise to decrease actuation point of opposite switch." Beneath the adjustment instructions was an "exploded" view of the switch assembly, which showed only one adjustment screw. During the adjustments, the I&C technician found that the "opposite" switches had not been adjusted, probably since 1977, and as a result, the TS alarm switch setting was out of specification. The inspector concluded that the miscalibration of the level switches had been caused by inadequate instructions contained in the instrument loop folder, and that this condition was contrary to Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Appendix A, step 8.b.(1)(ff), which requires specific procedures to be written for surveillance tests, inspections, and calibrations affecting level instrumentation of water storage tanks.

The technician notified his supervisor, corrected the switch settings, and annotated the loop folder to highlight proper identification of switch adjustment screws. I&C personnel stated that they discussed the discrepant switch setting with an engineer and concluded that the alarm would have actuated above the minimum level required by TS. The inspector could find no documentation for this review. However, the inspector confirmed by independent calculation that the alarm would have actuated above the TS minimum required CST volume. The Operations Shift Supervisor was not informed of the finding, and an Instrument Calibration Review (ICR) form was not initiated. The inspector reviewed procedure IC-2435A, "Instrument Calibration Review," which governs the documentation of abnormal calibration results, and references the plant information report process when calibration results are potentially reportable to the NRC. The procedure requires an ICR to be initiated when specifically directed by an I&C procedure or when directed by an I&C engineer or supervisor, or the I&C Department Manager. I&C personnel stated that in retrospect an ICR may have been appropriate, but that the corrective action taken had been considered to be sufficient. The decision also was influenced by the fact that instrument L-5280 is not safety-related.

Notwithstanding the satisfactory results of the licensee's abnormal setpoint review, the inspector considered that licensee failure to initiate an ICR had precluded management review of the incident for root cause and potential corrective actions, and indicated a Unit 2 I&C Department weakness in the program for identification and correction of instrument deficiencies. In addition, TS 6.8.1 requires written procedures to be established and implemented covering the activities referenced in Appendix 'A' of Regulatory Guide 1.33, dated February 1978. The inspector concluded that the failure to provide an adequate calibration procedure resulted in the repeated miscalibration of the CST level switch associated with the CST TS minimum level alarm. Thus, this NRC-identified **violation** will be cited **(VIO 336/93-28-06)**.

3.8 Qualification of Instrumentation and Control Technicians - Unit 2 (VIO 336/93-28-07 (IFI 336/93-28-07)

The inspector performed an evaluation of the Unit 2 Instrumentation and Controls (I&C) Department process for ensuring that technicians are formally qualified to perform calibration and surveillance tests on safety-related equipment. The NRC previously documented licensee weaknesses in this area in NRC Inspection Report 50-336/91-29. Administrative Control Procedure ACP-QA-8.27, "Millstone Station Training and Qualification," requires department heads to ensure that personnel have completed required training and are formally qualified prior to performing associated activities. I&C Department Instruction 1.11 describes the on-the-job training (OJT) program for Unit 2 I&C personnel. Qualification involves a combination of classroom training and evaluation by experienced OJT Evaluators of task performance in the field. When training on a specific task or procedure is completed, the OJT Coordinator forwards the information to the Nuclear Training Department, which updates the qualification matrix used by department line supervisors to assign work to the I&C technicians. Procedure ACP-QA-8.27, step 6.4.1.5, states that the line supervisor is responsible for designating only qualified individuals to perform independent work activities. If plant conditions prevent the assignment of qualified personnel, the line supervisor shall document the reason for assigning an unqualified individual, and what special provisions were made to protect personnel and equipment, and to ensure quality workmanship. Procedure IC-2450, "Unit 2 I&C Department Certification," step 6.11.2, requires the I&C supervisor to complete I&C Form 2450-6, "Justification for Use of Individual Not Having Documented Qualification," when assigning personnel to perform independent work on systems for which they do not have documented qualification. Form 2450-6 is used to document the compensatory actions required when training/qualification requirements for personnel to perform independent work cannot be satisfied. The compensatory actions include a pre-job briefing, review of the procedure, and/or increased supervision of the activity.

The inspector reviewed eight automated work orders involving calibration or surveillance testing of safety-related instrumentation by I&C technicians who, according to the department qualification matrix, were not formally qualified to perform the activities. (The work orders are listed in Attachment C of this report.) In each case, an I&C Form 2450-6 had been filled out and signed by a line supervisor indicating the appropriate compensatory actions that had been taken. The inspector interviewed the I&C technicians involved and found four instances in which the specified compensatory actions (pre-job briefings and/or procedure reviews) had not been performed. The degree to which the briefings or procedures reviews were performed in the remaining cases varied with the length of service and experience of the technicians involved, and was, in three cases, perfunctory; on some occasions, the pre-job briefing consisted of verbal verification by the line supervisor that the technician had performed the surveillance test previously. Through review of records for the affected surveillance tests and calibrations, the inspector concluded that the activities had been performed properly. However, the inspector also concluded that in the majority of cases, the compensatory briefings and procedure reviews had not been performed adequately. This is a violation of 10 CFR 50, Appendix B, Criteria II and V, which require that personnel performing activities affecting quality shall be trained as necessary to assure that suitable proficiency is achieved and maintained, and that activities affecting quality shall be prescribed by documented procedures, instructions and drawings. Specifically, procedures ACP-QA-8.27, step 6.4.1.5, and IC-2450, Step 6.11.2 were not followed. The inspector considered the incidents to be safety significant because they involved line supervisors. Consequently, this NRC identified **violation** will be cited. **(VIO 336/93-28-07)**.

The inspector reviewed the I&C Department qualification matrix. The matrix lists those of the fourteen I&C technicians at Unit 2 that are formally qualified to perform specific I&C Department activities. The inspector noted 5 procedures for which no technicians were qualified, and 25 procedures for which only one to three technicians were qualified. In addition, the inspector found ten cases where the OJT evaluator was not qualified to perform the surveillance test which he is assigned to evaluate. The inspector considered that the assignment of formally unqualified personnel through the Form 2450-6 process should occur rarely, and was concerned that the practice permitted by licensee procedures was being used to compensate for training program weakness. This concern was reinforced through discussion with a line supervisor who stated his opinion that the OJT program had not been functioning well in the last few years. The inspector discussed these observations with licensee management, but received no formal response by the end of the inspection period. This is an open item pending NRC review of the licensee's proposed corrective actions. **(IFI 336/93-28-08)**.

4.0 ENGINEERING (IP 37700, 37828)

4.1 New Fuel Receipt and Inspection Activities - Unit 1

The inspector observed new fuel receipt and handling activities at Unit 1. The review included an examination of station procedures, the Unit 1 Final Safety Analyses Report, technical specifications, interviews with licensee personnel, and observation of selected fuel handling activities.

While fuel was being moved from the lower level of the reactor building to the refuel floor, the inspector noted that safe loading paths were observed by the crane operators in accordance with procedure MP 790.4, "Control of Heavy Loads." The inspector verified that the cranes used to move the fuel had received preventive maintenance prior to use in accordance with procedure MP 795.1, "Pre-Outage Checklist." Slings which were used to move the fuel had been weight tested as required per procedure RE 1012, "New Fuel Receipt and Inspection."

Radiation surveys of the refuel floor during fuel movement activities were noted to be current. The inspector observed the inspection of two fuel elements. The inspector verified that the new fuel inspections were performed by trained personnel in accordance with procedure RE 1012. Personnel who were conducting the inspections had received training from the fuel vendor, General Electric. Movement of the fuel assemblies from the inspection stand to the new fuel storage vault was properly documented on fuel material transfer forms. Licensee personnel handled the fuel assemblies using due diligence and care. Overall, the inspector concluded that fuel inspection and receipt activities were being properly conducted at Unit 1.

4.2 Turbine Building Equipment in an Unanalyzed Condition - Unit 1

On December 30, 1993, at approximately 9:00 a.m., a plant equipment operator (PEO) noted that the Unit 1 turbine building railway access roll-up door had been closed. The door is required to be open to ensure the air temperature in the turbine building safety-related switchgear area remains within equipment qualification limits if a steam line pipe rupture in the turbine building occurred. The door was subsequently opened by the licensee.

Investigation of the event revealed that personnel who were working in the turbine building railway access area had closed the door approximately one and one half hours earlier to reduce the amount of snow blowing into the room and to increase the ambient air temperature. According to the licensee, the overhead door operating switch and a manual chain fall, which operate the door, were tagged with red "Do Not Operate" tags. The tags were visible to the plant personnel. The individual who had closed the door was immediately suspended from the site pending additional investigation.

Since the closing of the door potentially compromised the environmental qualification of the switchgear components, the plant was placed in an unanalyzed condition for a brief time. Accordingly, the licensee informed the NRC of this occurrence per 10 CFR 50.72(b)(ii)(A) as an unanalyzed condition that could have compromised plant safety.

Plant administrative control procedure (ACP) 2.06A Equipment Tagging states, in part, that personnel are not to operate red tagged equipment. The failure of the worker to adhere to procedure ACP 2.06A is a violation. However, per Section VII.B of the Enforcement Policy no violation will be issued since the licensee quickly discovered the event, and took timely and effective corrective action.

4.3 Potential Offsite Power Design Deficiency - Unit 1

On December 30, 1993, the licensee reported to the NRC that based upon recent electrical load studies of the Unit 1 electrical distribution system, the offsite electrical distribution system may not be as reliable as expected per 10 CFR 50, Appendix A, General Design Criteria. The licensee reported this discovery per 10 CFR 50.72(b)(1)(ii)(B) as a condition that is outside of the design basis of the plant.

According to the licensee, with a normal minimum switchyard voltage of 345Kv and the preferred source of offsite electrical power being supplied by the Reserve Station System Transformer (RSST), the voltage drop on electrical components due to loss of coolant accident response loading may be sufficient to reduce bus voltage below the degraded grid relay setpoints on safety-related busses. If this condition occurred during a design basis event, a loss of normal power (LNP) load shed signal would be generated and power would unnecessarily be transferred from the RSST to the onsite electrical sources - the gas turbine generator and diesel generator.

Normally the switchyard voltage is maintained at a nominal 357 Kv. According to the licensee, the switchyard voltage could drop to 345 Kv only if Units 2 and 3 are offline. In that event, the Unit 1 operations department has been instructed by memorandum to enter the Technical Specification (TS) Limiting Condition For Operation (LCO) for the RSST. The RSST LCO requires the plant to be isolated from the offsite grid in 72 hours if the discrepant condition cannot be repaired. To ensure Units 2 and 3 are aware of the operating restrictions that have been placed on the Unit 1 RSST, the operations departments for those units were issued memorandums informing them to contact Unit 1 if either of those units has to be taken offline.

The NRC Region I staff reviewed the licensees short term corrective actions and determined that they are acceptable. At the close of the report period, the licensee was evaluating several long term resolutions to the issue. One such solution involves reducing the loading on the RSST following a reactor trip by reducing the loads that restart on the safety-related buses when power is transferred from the Normal Station Services Transformer. Implementation of the long term corrective actions are scheduled for the January - March 1994 refuel outage. NRC will follow completion of these actions under previously **unresolved** electrical distribution functional inspection finding **(50-245/91-81-01)**.

4.4 Lost Documentation of Inservice Inspections - Unit 2 (URI 336/93-28-09) (VIO 336/93-28-10)

On November 4, 1993, during an audit of inservice inspection (ISI) records by the Quality Services Department (QSD), the licensee noted that several ASME Code Class II and III system leakage test records for tests performed during the refueling outage in the fall of 1990 could not be found. Affected systems included service water (SW), spent fuel pool (SFP) cooling, reactor building component cooling water (RBCCW), high pressure safety injection

(HPSI), low pressure safety injection/shutdown cooling (LPSI/SDC), containment spray (CS), main and auxiliary feed system (MFW/AFW), and vital chilled water. The corresponding procedures for these tests are EN21154, EN21155, EN21156, EN21157, EN21158, EN21160, and EN21161, respectively. The licensee documented the lost records on plant information report (PIR) 2-93-299, and initiated an operability assessment for the affected systems.

An engineering department operability assessment determined that all systems affected by the loss of records were operable. For those systems without records, leak tightness was assured through operator observations during daily rounds, monitoring of containment sump levels, performance of operations department leak tightness surveillances for LPSI/SDC, HPSI and CS systems, and hydrostatic testing conducted during the 1990 and 1992 outages in the SW system. On November 5, engineering department management informed the Plant Operations Review Committee (PORC) that the lost records were an administrative problem of minor significance, and system leakage tests of the affected systems would be reperformed in the near future. On November 6, the inspector discussed the loss of records with NRC Region I staff knowledgeable of inservice testing program. Based on the licensee's operability assessment and intent to reperform the applicable system leak tests, the NRC did not have significant concerns at that time.

During routine followup on December 6, the inspector determined through interviews with the ISI Coordinator that the validity of the ISI leak tests originally performed in the fall of 1990 could be in question. QSD audit A30180, "Pressure Testing," dated December 4, 1990, documented that the leak test procedures did not meet code requirements for: 1) documenting that proper test conditions were established or verified prior to performing VT-2 visual inspections; and 2) that the holding time requirements were satisfied prior to performance of the VT-2 visual inspections. The licensee performed the leak tests in 1990 using the same deficient procedures. The unit disputed these findings, but committed (letter MP-2-91-19 dated February 4, 1991) to revise the ISI leak test procedures prior to the next expected use. Although the licensee expected to complete the revisions and reperform the system leak tests during the 1992 outage, the procedures were not revised and no tests had been reperformed as of November 1993. Considering the implications of the QSD findings, the NRC is performing a review of the system leak tests to determine if they met applicable code requirements **(URI 336/93-28-09)**.

The licensee was not able to provide any other verification (i.e. log entries, accounts of individuals or ASME Level II certified inspectors who performed the testing, etc.) which would provide a high degree of assurance that the 1990 leak tests were conducted. The inspector was concerned that the licensee could not demonstrate how the requirements of technical specifications 3.4.10, 4.4.10, and 4.0.5 (structural integrity of ASME Code Class 3 components) were met for the previous 40-month ISI period, and requested the licensee to confirm the operability assessment for the affected systems.

The Engineering Department completed an operability assessment for the systems affected by the missing records and presented it to PORC on December 9. The assessment concluded that the only noncompliance was a failure to retain records as required by the code. The assessment was initially rejected by PORC when it learned that Northeast Utilities' ISI experts from the Berlin office had advised that without the ISI records, the TS requirements were not met. After further deliberation with ISI and licensing personnel, the PORC eventually concluded that all affected systems were operable, and the loss of ISI leak test records was a nonconforming condition. Licensee corrective actions included: the generation and disposition of a nonconformance report (NCR) to document the loss of ISI records; the approval of system leak test procedures still under revision; the completion of ASME system leak tests on all accessible piping as soon as possible; and the completion of ASME system leak tests of systems inside containment during the first available shutdown. The licensee completed system leak tests of all accessible systems on January 4, 1994.

The NRC held a phone conference with the licensee on December 10 to review the facts surrounding the loss of ISI leak test records. Although lack of documentation of TS required surveillance without some substantial evidence is normally considered failure to complete the surveillance, the NRC concurred with the licensee's operability assessment for this particular instance, and corrective actions to reperform all leak tests outside of containment and perform the tests inside containment at the earliest opportunity. Assurance of leak tightness inside containment would be provided by alternate methods such as sump level indication and containment moisture indication.

The inspector investigated the events surrounding the lost ISI records. The completed ISI records were not transmitted to the Nuclear Documents Storage Facility (NDSF) within 1 year, as required by procedure ACP-QA-10.04, "Nuclear Power Plant Records." The ISI coordinator stored the completed ISI leak test records on his desk from the time the tests were completed in the fall of 1990 until 1993, and subsequently lost. The inspector reviewed the licensee's definition of "quality assurance records" and "working documents," and procedural requirements for the storage and transmittal of working documents to the Nuclear Documents Storage Facility (NDSF). ANSI/ASME N45.2.9 - 1974 states that a document is considered a quality assurance record when the document has been completed. The licensee has taken exception to ANSI/ASME N52.2.9 - 1974 requirements for quality assurance records, and does not consider completed documents as quality assurance records until transmitted to the appropriate NDSF. In the interim, the documents are considered "working documents," and controlled under section 6.1 of procedure ACP-QA-10.04. As a result, there was minimal control exercised over the storage and handling of the ISI leak test records, and ultimately the records were lost. The inspector was concerned that records which are important plant records may not be handled appropriately as evidenced by the above finding.

The failure to maintain completed ISI records is not consistent with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Article IWA 6340. Additionally, the completed system leak test results were not included in the 1990 ISI summary report (dated

February 4, 1991) to the NRC as required by procedure ACP-QA-9.09, "Management of ISI Programs." These **violations** of ISI record storage and reporting requirements will be cited **(VIO 336/93-28-10)**.

The inspector identified several concerns including the quality of the initial operability assessment submitted to PORC by the engineering department in November 1993; corporate ISI experts were not consulted as to the significance of the lost ISI records immediately upon discovery; the QSD findings from 1990 and their implications, as well as the commitments to revise the procedures and reperform the system leak tests were not addressed; all of the corrective actions delineated by the subsequent December 9 operability assessment, including the NCR to document the missing records, were not identified or completed until after the inspector caused the issue to be re-addressed on December 6. The inspector concluded that the November 4 assessment did not provide the necessary detail required by management to adequately assess the problem, and management attention to the quality of operability determinations is warranted.

4.5 Spurious Overtemperature-delta Temperature and Overpower-delta Temperature Runback and Trips - Unit 3

On November 17, 1993, the licensee reduced reactor power to 98 percent due to spurious overtemperature-delta Temperature (OTdT) and overpower-delta Temperature (OPdT) runback and channel trip signals. The licensee attributed these occurrences to hot leg temperature streaming and periodic temperature fluctuations originating in the reactor vessel upper plenum. On December 5, the licensee adjusted the runback signal from 3 to 1 percent below the trip signals and increased power to 100 percent.

The OTdT trip provides core protection to prevent departure from nucleate boiling (DNB) for all combinations of pressure, power, coolant temperature, and axial power distribution, provided the transient is slow with respect to piping transit delays from the core to the temperature detectors. The setpoint is automatically varied with respect to changes in coolant temperature, pressurizer pressure, and axial power distribution. The OPdT trip protects the core from over power conditions and provides assurance of fuel integrity. This setpoint is automatically varied with coolant temperature and the rate of change of temperature. Both the OTdT and OPdT trip setpoints are continuously calculated. Prior to reaching either setpoint, rod withdrawal is inhibited and a cyclic turbine runback is initiated. The function of the runback is to attempt to eliminate the cause of an impending reactor trip. This previously occurred if 2 of 4 channels were within 3 percent of either the OTdT or OPdT trip setpoints.

Hot leg temperature streaming is a steady state phenomenon associated with incomplete mixing of the core exit temperature gradient. This results in a higher measured hot leg temperature than actual and results in lower OTdT and OPdT trip setpoints. The reactor vessel upper plenum anomaly is a phenomenon characterized by a step increase in temperature in one hot leg. The loop remains at the higher temperature for several seconds then returns to the original temperature. Simultaneously, the adjacent hot leg temperature decreases by the same amount for the same time period. Westinghouse reported this phenomenon to the NRC in a memorandum dated July 24, 1992. The periodic hot leg temperature changes result in small, but very rapid changes in average temperature (T-avg) and loop delta-T for the affected loops. The lead/lag characteristic of the OTdT and OPdT circuitry interprets these changes as a large T-avg change, and calculates large OTdT and OPdT setpoint penalties accordingly. Because of the penalties, alarms and single channel runback actuations precluded normal system testing and distracted operators at 100 percent power operations.

Unit 3 had experienced the upper plenum flow anomaly since initial start up; however, the magnitude and frequency have increased during this cycle. The licensee believes that this is due to the small reduction in reactor coolant flow (as a result of the change out of all four reactor coolant pumps) and a slightly lower core leakage loading pattern (lower enrichment or higher burnup at the periphery of the core).

As short term corrective action in response to the frequent alarms, the licensee maintained T-avg low in the allowed band, reduced reactor power to 98 percent, and maintained axial flux difference at approximately 3 to 4 percent. These actions were implemented to maximize the OTdT and OPdT setpoints. In addition, prior to performing surveillances which result in taking one loop/channel out of service, power was further reduced to provide additional margin to the trip and runback setpoints. On December 5, plant design change record (PDCR) MP3-93-218 was approved to raise the turbine runback setpoint to within 1 percent of the trip setpoint to minimize the potential to prematurely initiate a turbine runback and allow the plant to operate at 100 percent power. The licensee concluded that changing the setpoint to 1 percent below the trip setpoint would continue to provide adequate protection against reactor trips for slow heatup transients with the rods in automatic control. The licensee further stated that with rods in manual, the operators may not be able to respond fast enough to prevent a trip whether the current 3 percent setpoint or the revised setpoint was used. Therefore, the probability of a trip resulting from a heatup transient is not significantly affected by the change.

The inspector reviewed the PDCR, technical specifications, final safety analysis report and discussed the phenomenon with the licensee. The inspector determined the licensee's response to these phenomenon to be good and would prevent inadvertently tripping the reactor and placing it in a transient condition. The inspector had no further questions.

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

5.1 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 inspector 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 dated December 14, 1993 for November 1993.

LER 50-245/93-14-00 dated October 25, 1993, identified that the control room may be rendered uninhabitable following a design basis event as a result of leakage from the Standby Gas Treatment System. This issue is reviewed in section 5.2 of this report.

LER 50-245/93-20-00 dated November 22, 1993, reported that the diesel generator was out of service from May 22, 1986, to July 22, 1986. This event is discussed in section 5.3 of this report.

LER 50-245/93-23-00 dated December 10, 1993, discussed a plant shutdown because of degraded service water piping downsteam of the Reactor Building Component Cooling Water heat exchanger. This event was previously reviewed in NRC inspection report 50-245/93-27.

LER 50-423/93-004-01 dated August 31, 1993, discussed a plant trip due to an electohydraulic control power supply failure. This event was previously discussed in NRC Inspection Report 50-423/93-07.

LER 50-423/93-007 dated July 9, 1993, reduction in emergency diesel fuel oil storage capacity was documented in NRC Inspection Reports 50-423/93-07 and 50-423/93-13.

5.2 Standby Gas Treatment System Deficiency Discovered - Unit 1 (LER 50-245/93-14)

On September 23, 1993, the licensee determined that two one-half inch holes that were located on the discharge of the Standby Gas Treatment (SBGT) system fans potentially rendered the control room uninhabitable following a design basis event. The holes were subsequently plugged by the licensee and the control room ventilation system was restored to an operable status. Installation of the plugs was documented per bypass jumper 9-24-93. The licensee reported the discovery of the holes to the NRC per 10 CFR 50.72(b)(1)(ii) as a condition outside of the design basis of the plant.

The inspector noted that portions of the control room ventilation system, which are under a negative pressure, are approximately 30 feet from the SBGT system. The licensee theorized that following a design basis event, the holes in the SBGT system would allow radioactive particulate and noble gases to escape into the heating and ventilation (H&V) room atmosphere. The radioactivity could then be drawn into the control room ventilation system through seal in-leakage. The licensee postulated that the air in-leakage could result in control room dose rates to operators exceeding the maximum 0.5 rem dose rate in any eight hour period following a design basis event, which is outlined in the Unit 1 Final Safety Analyses Report.

The inspector noted that the licensee's assumptions were conservative for several reasons. For example: the licensee did not assume dilution of any of the radionuclides with air from the outside environment. The inspector noted that some dilution would occur since dampers in the H&V room are permanently open to the outside environment. Further, the control room ventilation system is deenergized following a design basis event. To restart the ventilation system, operators must enter the H&V room and operate switches at the H&V panel. If the H&V room contained excessive airborne activity, it is unlikely that personnel would enter and restore the ventilation system. Therefore, alternate cooling would have to be established for the control room by opening doors.

While reviewing this event, the inspector noted a weakness in the licensee review of TMI action item II.B.2.2, "Plant Shielding" contained in NUREG 0737, "Clarification of TMI Action Items." This item required licensees to evaluate operator actions which would be required following an accident and determine if the plant areas were accessible for entry. The licensee did not consider that entry into the H&V room would be required by operators to restore control room ventilation if a design basis accident occurred. Accordingly, post accident radiation levels were not estimated for the H&V room by the licensee in their review of item II.B.2.2. Without having performed an estimated analyses of the post accident radiation levels in the H&V room, the licensee does not know if the room is accessible to operators following a design basis event. To ensure the H&V room and other plant areas are accessible following a design basis event, the licensee committed to review the unit emergency operating procedures and ensure that areas which operators must enter are accessible. This review is to be completed prior to startup from the spring 1994 refuel outage.

Unlike plants of a later vintage, Unit 1 does not have a specific Technical Specification concerning control room operability during plant operation. However, TMI action plan item III.D.3.4, "Control Room Habitability" required, in part, that the licensee protect operators against the effects of accidental release of toxic and radioactive gases. The licensee's response to this item dated July 1, 1981 is currently under NRC review as part of the Integrated Safety Assessment Planning (ISAP) process. The licensee concluded that the holes in the SBGT system may increase the dose to operators in the control room to levels which were greater than what was assumed in the FSAR. The inspector noted, however, that the licensee used conservative assumptions when conducting their evaluation. According to the licensee, use of more realistic plant assumptions would not place the dose rates in an unanalyzed state. The inspector had no further questions.

5.3 Diesel Generator Support Equipment Inoperable - Unit 1 (LER 50-245/93-20)

On October 21, 1993, the licensee determined that a ventilation system supporting the operability of the diesel generator was out of service for a two month period from May 22, 1986, to July 22, 1986. The licensee reported this condition to the NRC in accordance with 10 CFR 50.72(b)(2)(iii)(d) as a condition that alone could have prevented the fulfillment of the safety function of systems that are needed to mitigate the consequences of an accident. This event was documented in License Event Report 93-20-00, which was submitted to the NRC on November 22, 1993.

The diesel generator room air temperature is maintained below design limits by two non-redundant space coolers. During the two month period, one of the two ventilation room coolers was out of service. Based upon recent testing, both coolers are required to maintain the temperature of the room within design parameters under all diesel generator loading conditions. Consequently, during the two month time in which the room cooler was out of service, the diesel generator may not have been able to meet all of its performance specifications.

Unit 1 Technical Specification (TS) 3.5.F.2, Core and Containment Cooling Systems, allows the diesel generator to be out of service for seven days provided the other emergency power supplies remain operable. The inspector noted that in addition to not meeting the out of service time requirements of TS 3.5.F.2, the system operability requirements of the specification were not met. Specifically, the gas turbine was also removed from service for approximately six hours during the two month period to facilitate maintenance activities.

To ensure plant operators understand the nexus between the diesel generator operability and the room coolers, the licensee inserted a memorandum into the Unit 1 TS. The memorandum informs operators that both room air coolers are required to be operable to support diesel generator operability.

The inspector considered the licensee corrective action to be appropriate. The inspector noted that the licensee reported an historical event. Due to the age of the TS noncompliance, (greater than five years) and the fact that the event was identified as a result of new licensee understanding of the diesel generator auxiliary equipment support function, no enforcement action will be taken per Title 28 chapter 163 of the United States Code Service 1991.

5.4 Timeliness of Licensee Event Report Submittals - Unit 1 (VIO 245/93-32-11)

On December 10, 1993, the licensee submitted Licensee Event Report (LER) 93-23. This LER documented the October 15, 1993, discovery of degraded service water piping downstream of the Reactor Building Component Cooling Water (RBCCW) heat exchangers. This event was discussed in NRC inspection report 50-245/93-27. The inspector noted that the LER was submitted almost 60 days beyond the event date. The licensee stated that the LER was submitted late because of administrative error.

Since February 1992, three other LERs (92-02-00, 92-18-00, 93-06-01) have been submitted late because of administrative weaknesses. Although the failure to meet LER timeliness requirements had no safety consequence, the recurrence of this violation demonstrates that licensee corrective actions to date have not been effective. Therefore, in accordance with Section VII of the NRC Enforcement Policy, this violation of 10 CFR 50.73(a) will be cited. **(VIO 245/93-32-11)**.

5.5 Review of Previously Identified Issues

5.5.1 Review of Industry Operating Experience - Unit 3 (URI 423/93-13-07)

The inspector conducted a review of the licensee's program to evaluate operating experience information provided by the NRC, INPO and their own internal reporting system. Specifically, the inspector reviewed NEO 2.06, "Operating Experience Assessment and Utilization," NEO 4.01, "Communications with the Nuclear Regulatory Commission," NSE 4.01, "Operating Experience Assessment," and NSE 4.02, "Screening Operating Experience Information." The inspector discussed the implementation of the licensee's operating experience assessment program, the handling of internal and external operating experience, and the timeliness goals for processing this information with the Manager of Nuclear Safety Engineering. The inspector reviewed the following operating experience files to determine the adequacy and timeliness of the review performed: Q 92064, Q92076, Q92100, Q92058, Q92124, Q93008, Q92101 and NU SOERs 93-01 & 93-02. The information contained in the files indicated that the reviews were thorough and for the most part timely, with some delays in the Summer of 1993 apparently due to competing staff priorities. All questions raised by the inspector regarding the handling of this information were acceptably resolved.

The licensee's program for evaluating and incorporating industry information from Information Notices was reviewed with the Nuclear Licensing Department. The inspector noted that the licensee adopted improvements in their method of tracking such correspondence and has a goal of achieving an initial review and response to the Information Notice issue within 90 days. The inspector reviewed the handling of INs 92-06 & -07 and 93-08, -16, -17, -23 & -25. The initial review and tracking of the INs was good; however, followup corrective action on the issues which are applicable to the units remained incomplete. The inspector reviewed the outstanding open INs for Millstone and Haddam Neck which had 75 and 37 INs open, respectively. Although the number of incomplete actions was high, the backlog of INs appeared readily manageable with less than one-fourth of the INs predating 1993.

The inspector also reviewed the licensee's newly revised procedure, NEO 6.13, "Processing Vendor Information," for tracking and incorporating vendor information into procedures. The inspector noted that the program relies upon trained vendor information coordinators at Millstone, Haddam Neck and the Berlin corporate office to evaluate and distribute the information received from vendors. The program was only recently revised and improved to address performance concerns in this area; thus the program was too new to evaluate for effectiveness. Pending the completion of the inspector review of the licensee's program for handling operating experience information, particularly the incorporation of vendor information, this item remains **open**.

5.5.2 Post-Accident Monitoring Instrumentation - Unit 2 (URI 336/91-16-02)

Inspection Report 50-336/91-16 notes that, for Unit 2, there are a number of differences in post-accident monitoring instrumentation (Regulatory Guide 1.97) when comparing FSAR and licensee submitted information with actual control room observations for the same instrument. Differences in instrumentation units and ranges were noted. However, the licensee's commitment for implementation of Regulatory Guide 1.97 requirements was not scheduled for completion at the time of the previous inspection.

During this inspection, the inspector reviewed the updated Unit 2 FSAR Section 7.5.1.4, "Post-Accident Monitoring," dated June 1993, which supersedes previously submitted Regulatory Guide (RG) 1.97 data. The FSAR update includes a revised Table 7.5.3, dated May 1993, which contains entries for RG 1.97 Variable, Parameter, Instrument (Loop) ID and Instrument Range for each RG 1.97 instrument. The inspector compared FSAR Table 7.5.3 data with control room observations for each case where a discrepancy was noted in findings 50-336/91-16-02. In addition, the inspector made a number of additional comparisons on a random basis. Based upon the comparison of FSAR data with the currently installed, control room instrumentation, the inspector concluded that the description of the subject instrumentation in the FSAR is accurate and no violations existed. This item is closed.

5.5.3 Use of Meter After the Calibration Due Date - Unit 2 (URI 336/91-20-03)

The licensee was to evaluate the use of a Fluke 5100B meter that was past the calibration due date. The inspector reviewed Instrument Nonconformance Report (INCR) 4129, dated February 26, 1992, regarding the disposition of the use of a Fluke 5100B meter six days after the calibration due date. The licensee used this instrument after a voltage comparison was done between this instrument and two other calibrated instruments; the results were nearly identical and provided confidence that the Fluke meter had not drifted out of calibration. Based on this voltage comparison, as well as, the excellent past history record of this instrument, I&C management deemed the use of this instrument past the calibration due date was acceptable. Subsequent calibration of the instrument by a vendor indicated that no adjustments were necessary to the device.

As a result of this matter, the licensee incorporated written guidance in procedure ACP-QA-9.04, "Control and Calibration of Measuring and Test Equipment," to document the justification for the use of measuring and test equipment (M&TE) past the normal calibration due date. The justification criteria and approvals are sufficiently stringent to strongly discourage this procedure unless absolutely necessary and provide some assurance that the instrument remains acceptable for use. The above noted example represented an adequate handling of an M&TE calibration lapse. No violation was identified. Based on the licensee's actions in this matter, this item is considered **closed**.

5.5.4 Calibration of Seismic Monitors - Unit 2 (VIO 336/91-28-03)

Inspection Report 50-336/91-28 notes that "...the incorrect performance of the channel calibration per surveillance procedure SP 2405D and the inadequate acceptance criteria contained in that procedure failed to insure the operability of the seismic monitors since the last calibration in October 1990."

The inspector reviewed procedure SP 2405D, Rev 4, dated January 10, 1992, which is used to verify proper operation of the seismic monitors. The inspector noted that the procedure contains the recommended acceptance criteria of 0.1 plus/minus 0.005 inches for the lateral and transverse directions and 0.2 plus/minus 0.005 inches for the vertical direction. The inspector also noted that page 11 of the procedure contains a diagram showing how the test trace should look and how to measure the trace relative to the "zero" reference point. The licensee informed the inspector that seismic monitors that do not meet the acceptance criterion are, at Unit 2, not recalibrated but are replaced.

The inspector reviewed surveillance test data taken on December 29, 1992. The data for seismic monitor SN092 failed to meet the initial surveillance test acceptance criteria; the unit was subsequently replaced and passed a retest. Seismic monitors SN088 and 089 passed the surveillance test, but were replaced due to lose/broken parts and passed the subsequent surveillance testing. The inspector used the instructions contained in procedure SP 2405D to interpret the test data and agreed with the licensee's interpretation that the reinstalled seismic monitors are operable. This item is **closed**.

5.5.5 Conformance with Housekeeping Requirements - Unit 2 (URI 336/91-31-01)

Inspection Report 50-336/91-31 described various instances where the licensee stored unanchored material adjacent to safety related components, which was not consistent with the seismic considerations described in procedure ACP-QA-4.01, "Plant Housekeeping," Section 6.4.7. In addition, licensee corrective actions for that finding did not ensure conformance to procedure ACP-QA-4.01 requirements.

The inspector reviewed Revision 16 of procedure ACP-QA-4.01 as well as the measures taken by the licensee management to implement and enforce elements of the procedure. During an extensive tour of Unit 2 and a limited tour of Unit 3, the inspector noted general conformance with the requirements of procedure ACP-QA-4.01, in particular the tying off of equipment and maintaining areas clean and well lighted. The inspector noted that the licensee initiated an effort to clean up and paint Unit 2 areas in March 1993. Particular improvement in the A & B diesel rooms and in the reactor building closed cooling water heat exchanger areas were noted.

The safety significance of the finding was relatively low as the inspector found no instance in which there was actual damage to safety-related components. Licensee corrective actions in response to this finding were acceptable, and enforcement discretion will be exercised per section VII.B of the enforcement policy. This item is considered closed.

5.5.6 Failure to Implement Effective Corrective Action for Procedural Adherence Problems - Unit 3 (VIO 423/91-04-04)

The licensee's response to this violation dated June 14, 1991, detailed a broad range of corrective actions taken to improve procedural adherence including: 1) increased supervisory oversight, 2) procedural enhancement, 3) work observation by the line and quality assurance (QSD) organizations, and 4) increased emphasis by management. Since that time, the work observation program was implemented and tracked an initial steady improvement in procedural adherence followed by a plateauing in the success of the procedural adherence efforts. The licensee recently began publishing a work performance trend report, which provides to management the results of the work observation program and the QSD surveillance program to closely monitor work control and procedure adherence. The procedure enhancement efforts have progressed. The work observation program consistently indicates that the problem with procedural adherence lies in poor job performance and the violation of industrial safety rules rather than procedural inadequacies. Increased management and supervisory oversight of and emphasis on procedural adherence has been noted by the NRC at Unit 3 with some measurable degree of success, although improvement efforts continue. Other examples of procedure noncompliance have been identified by the NRC since that time, corrective actions for which continue to be reviewed by NRC. Inspection followup items remain open concerning those corrective actions. The licensee's performance in this area remains of concern to the NRC and continued inspection emphasis in this area continues. However, based on the licensee's progress made to date in procedural adherence at Unit 3 due to the above noted corrective actions as well as the continued licensee emphasis, this item is considered closed.

5.5.7 Minimum Flow Capacity of Safety Related Pumps - Unit 3 (URI 423/91-07-01)

This item was opened to track licensee documentation of adequate minimum flow capacity for certain safety-related pumps. The licensee concluded that the piping configuration for the Safety Injection (SIH), Charging (CHS) and Auxiliary Feedwater (AFW) Systems precludes the potential for deadheading a pump during minimum flow operation.

The inspector reviewed licensee's documentation regarding the adequacy of the minimum flow provisions of the above noted pumps. No system modifications were determined to be warranted to increase pump minimum flow. The adequacy of the minimum flow for the SIH pumps was noted to be marginal, but the very limited frequency and duration of pump operation indicate that the pump minimum flow remains acceptable. The inspector was concerned with the adequacy of the minimum flow provisions for the AFW pumps due to a previous indication of pump casing wear, which required weld repair. Inspector discussions with engineering personnel indicated that the casing wear was attributable to an original casting problem and possibly minimum flow operation. However, the wear was very minor and pump disassembly revealed no other indications of pump degradation due to minimum flow operation. The licensee's IST program on the safety-related pumps is capable of detecting noteworthy pump wear due to low flow operation via flow and vibration monitoring. Furthermore, operation of the pumps in minimum flow conditions (or all other modes for that matter) is very limited, with most Unit 3 safety-related pumps to date having fewer than 100 hours of run time.

The inspector noted that the licensee also initiated efforts to document the adequacy of the minimum flow provisions for the similar pumps at Units 1 & 2. The efforts at Unit 1 that are nearing completion and the work to date at Unit 2 indicate that the current minimum flow provisions for the ECCS pumps are acceptable. Based on the licensee's documentation and evaluation efforts and findings to date, no violations were identified, and this issue is considered **closed**.

5.5.8 Minimum Flow During Parallel RHR Pump Operation - Unit 3 (URI 423/91-07-02)

This item was opened to follow the licensee's evaluation of Bulletin 88-04, "Potential Safety-Related Pump Loss," which indicated that the residual heat removal (RHR) pumps at Unit 3 were not susceptible to deadheading in a parallel pump configuration since each pump is equipped with a check valve on the suction side of the pump. However, at the time of that inspection, test results or detailed analyses to support the above conclusion were not available for review. The inspector reviewed Westinghouse analysis NEU-91-574, dated June 3, 1991, which evaluated the potential for RHR pump damage during parallel pump, minimum flow operations. The analysis supported the licensee's previous conclusions in this matter. The inspector also reviewed the inservice test results for RHR suction valves SIL*V003 & V009 in the checked to close position for the period from April 1992 to July 1993. All test results were determined to be acceptable. This item is **closed**.

5.5.9 Environmental Qualification of Power Operated Relief Valves - Unit 3 (URI 423/92-13-03)

NRC inspection in 1992 identified discrepant gasket material used in the pressurizer power operated relief valve (PORV) enclosures. The PORV temperatures were also measured to be higher than evaluated by the equipment environmental qualification (EEQ) process. Grafoil type gaskets were found in the electrical enclosures for PORVs 3RCS*PCV455A and 456. The EEQ vendor test report stipulates that the solenoid housing and the limit switch housing assemblies are environmentally sealed. The environmentally qualified configuration for the PORVs utilizes an Ethylene Propylene Diene Momer (EPDM) type material as the gasket. The licensee could not produce any documentation supporting the use of Grafoil type gaskets to maintain an environmentally qualified boundary. The use of Grafoil gaskets in the PORV electrical enclosures and the cause of erroneous temperature information in the EEQ file remained unresolved.

The licensee's Plant Information Report (PIR) 3-92-171 indicated that the root cause of the discrepant gasket materials in PORVs was deficient change management which resulted in the implementation of the Grafoil gasket change without the appropriate documents being updated. By letter dated June 3, 1992, the Westinghouse Electric Corporation submitted a report in response to the licensee's request concerning the replacement of the EPDM gaskets with Grafoil gaskets. The letter states, "The replacement ... is acceptable with regard to environmental qualified life." The Grafoil material can withstand temperatures of 900°F and has a radiation capability of 1.5E9 Rads total integrated dose (TID), which would result in a qualified life of forty years. EPDM is designed for 8.8E6 Rads and 300°F. The letter also answers questions related to the replacement, such as the change in thickness of the gaskets. Though the Grafoil gasket material was environmentally qualified in a subsequent evaluation, there was no proper documentation to support the qualification when initially installing the Grafoil gaskets. The inspector found that use of the Grafoil type gaskets in the PORV electrical enclosures is justified since the licensee produced adequate documentation.

The initial reason that the licensee replaced the EPDM gaskets with Grafoil gaskets was to address concerns of higher than anticipated valve temperature degrading the life of EPDM gaskets. The elimination of the PORV loop seal during original construction, to minimize the hydraulic transients anticipated as a result of a water slug travelling down the piping following the cycling of a PORV, resulted in higher area temperatures than initially assumed in the qualification test reports. The higher temperatures would result in a shorter qualification life for the EPDM gaskets. Although technically acceptable based on the subsequent reviews performed, the Grafoil gaskets were installed contrary to the gasket material specified on Component Replacement Schedule sheets and valve design drawings, based on previous awareness of documentation supporting installation of Grafoil gaskets in other applications. The root cause was identified as a management deficiency which resulted in the premature material change decision and improper design change implementation. The failure to ensure that the design basis for the PORV was correctly translated into specifications, drawings, procedures, and instructions is in violation of 10 CFR part 50 Appendix B Criterion III.

The inspector noted that the licensee took appropriate corrective actions to prevent recurrence. According to the plant PIR 3-92-171, the licensee determined the operability of Grafoil gaskets and an evaluation allowing the use of Grafoil gaskets was provided by Westinghouse. Information on the PORV position switch and solenoid cover gaskets has been incorporated into the plant preventive maintenance lists. To address the more general question of maintaining EEQ during/following maintenance, the licensee has revised plant Administrative Control Procedure (ACP) ACP-QA-2.02 to provide additional reviews to identify requirements to maintain the quality aspects of environmentally qualified components. In addition, due to previous licensee identified weaknesses in the design change process, the Project Services Department was developed in 1991 to have the responsibility for performing all design changes. Although the failure to update the design basis does constitute a violation, it was identified and corrected by the licensee and was of minor safety significance. Therefore, per section VII. B of the NRC enforcement Policy, enforcement discretion was exercised and no violation will be issued.

In conclusion, the use of Grafoil material for the PORV's solenoid housing gasket and limit switch housing gasket is acceptable. The high temperature at the PORVs was due to the elimination of the loop seal during original construction. The licensee provided adequate documentation to address the concerns related to the use of Grafoil material for the PORV gaskets. This item is **closed.**

6.0 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 January 21, 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. Except as noted in Section 2.5 of this report, no written material regarding the inspection findings was given to the licensee during the inspection.

ATTACHMENT A

MEMORANDUM FOR: Bill Temple

FROM: Doug Dempsey

DATE: October 15, 1993

SUBJECT: RCS Leak Detection Systems - Unit 2

REFERENCE: Memorandum Kacich to Scace, NL-93-568, dated 9/29/93

With regard to the referenced document, please provide answers to the following questions.

1. Does NNECO plan to change the setpoints on RMs 8123 and 8262?

   My present understanding is that the fixed setpoint will be changed to a variable set point similar to the steam generator blowdown RMs. Confirm?

   To what extent will the alarm setpoints correspond to actual RCS activitity and the "1 gpm in one hour" criterion of RG 1.45?

   What is the schedule for implementation of the above?

2. Regarding the present setpoint: With the present RCS activity, how long would it take to alarm assuming a 1.0 gpm leak rate?

3. Assuming RCS activity in the Environmental Report, what would be the time to alarm?

4. Is there any plan to change the design basis of the system? For example, if the RG sensitivity cannot be achieved w[illegible] current RCS activity levels, what about changing the FSAR simil[illegible] to Unit 3? In other words, is the system meeting the design basis of the plant <u>now</u>?

5. Does NNECO intend to provide the operators with "approximate relationships converting these signals (RM) to units of water flow...to assist the operators in interpreting signals" (RG 1.45, page 3, Detector Response Time) and "Procedures for converting various indications to a common leakage equivalent..." (RG 1.45, page 4, item 7)

   A simple yes or no will suffice.

6. With regard to conversations with NRC Technical Specification Branch (pp 4 and 5 of the reference memo):

   a. Please provide the telecon memorandum documenti[illegible] the conversation
   b. When and with whom did the conversation take pl[illegible]e?
   c. Was the NRC position to which you refer obtained in writing? If so, please provide a copy.

ATTACHMENT 6

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY
WESTERN MASSACHUSETTS ELECTRIC COMPANY
HOLYOKE WATER POWER COMPANY
NORTHEAST UTILITIES SERVICE COMPANY
NORTHEAST NUCLEAR ENERGY COMPANY

MEMO

November 18, 1993
RB-93-515

TO: R. H. Young

FROM: R. A. Crandall *R.A. Crandall*
(Ext. 5863)

SUBJECT: Responses to Millstone Unit No. 2 RCS Leakage Detection Questions

Reference: Memo D. A. Dempsey to W. J. Temple, dated October 15, 1993

The following are in response to the questions in the referenced memo. They are related to the capability of the Millstone Unit No. 2 containment air radiation monitor to detect reactor coolant system (RCS) leakage. Please transmit these responses to Mr. Dempsey.

Question 1: Does NNECO plan to change the setpoints on RMS 8123 and 8262?

Response 1: Yes. The current setpoints are fixed values based on a calculation of required purge valve closure to meet 10CFR20 concentration limits. These fixed setpoints are typically much higher than normal monitor readings. The setpoints which provide a high rad alarm and annunciation will be lowered to a value of approximately two times the current normal reading. This will be a variable setpoint that will provide the maximum sensitivity to changing radiological conditions without resulting in numerous spurious alarms.

Question 1a: To what extent will alarm setpoints correspond to actual RCS activity and the "1 gpm in one hour" criterion of R.G. 1.97?

Response 1a: See response to Question 2.

Question 1b: What is the schedule for implementation of the above setpoint changes?

Response 1b: The above setpoints are expected to be implemented by December 17, 1993.

Question 2: Regarding the present setpoint, with the present RCS activity, how long would it take to alarm assuming a 1.0 gpm leak rate?

And Question 3: Assuming RCS activity in the Environmental ! ›port, what would be the time to alarm?

Response 1a, 2, and 3: Correlation of an airborne gaseous monitor (8123B and 8262B) reading to a leak rate of RCS is dependent on the following factors:

1. Current Reactor Coolant Noble Gas Activity Level

This factor is known and could be accounted for during steady state conditions, but would require numerous changes in correlation factors over a cycle. During transient conditions (e.g., changing power levels) uncertainties up to a factor of 100 are possible.

2. Noble Gas Nuclide Mix

The radiation detector responds differently to each radionuclide. To convert counts per minute to μCi/cc an assumption must be made as to the monitored mix. The actual mix will be variable. Because of the short half life of many noble gas nuclides, the mix in containment will be different from that in the RCS. The containment mix will be constantly changing from the time the leak starts until an equilibrium mix is achieved. Since the Millstone Unit No. 2 monitors are beta scintillators, they are not as sensitive to nuclide mix changes as gamma detectors, but this factor still adds uncertainties of up to a factor of 3.

3. RCS Activity at the Location of Leak

The RCS activity measured daily by chemistry grab samples is not representative of the activity at all locations in the RCS. For example, if the leak was from the charging line, the coolant has been through the degasifier, demineralizers and volume control tank. Noble gas actually could be 100 times less than the measured RCS activity. Activity in the pressurizer steam space will be significantly different than in the pressurizer liquid space, which will be different than measured RCS activity.

4. Location of Leak in Relation to Sample Point

Calculations must assume all activity is homogeneously mixed within the containment volume. It will not be. Airborne concentrations near the leak location will be higher than other locations. Hence, the distance and air flow patterns between the leak location and sampling point are important. In the short term (<1 hour) such uncertainty could be a factor of up to 1000. Over the longer term such uncertainty should be less than 10.

5. Leak Rate and Time Since Start of Leak

One cannot correlate a detector count rate with a leak rate as the count rate is also dependent on the length of time the leak has existed. For example, a 10,000 cpm count rate could be due to a 1 gpm leak existing for 5 hours or a 10 gpm leak existing for 0.5 hours. Thus the leak rate is really related to the rate of change of the detector count rate (or the slope of an analog plot). Of course, the rate of change of count rate will change with time as equilibrium concentrations are approached or as RCS leak rate changes. This dynamic situation adds additional uncertainties in leak rate determination.

6. Background Variation

The detector count rate is not only dependent on the concentration and mix of the monitored sample, but also on ambient backgrcund, electronic noise, or the existence of other radioactive nuclides in the sample (e.g., radon). All of those factors are subject to change, resulting in uncertainty in the count rate due to the nuclides of interest.

7. Sampling and Counting Uncertainties

Errors in the measurement also add uncertainty. For example, sample line in leakage could dilute the sample. Changes in detector sensitivity or discriminator settings with time add uncertainty.

Based on the above, it is clear that there are many uncertainties in attempting to correlate a gaseous monitor reading with an RCS leak rate. Since mary of these factors would be unknown at the time of the 'eak, an accurate correlation would not be possible.

However, for the sake of answering the above questions related to the sensitivity of the monitors, a number of simplifying assumptions can be made.

Therefore, calculations were performed based on the following assumptions:

a. Xe-133 is the only nuclide of significance and detector response is based on Xe-133 response

b. Xe-133 activity is equal to

   18.1 μCi/cc for Environmental Report calculation
   0.13 μCi/cc for current RCS activity calculations

c. Instantaneous homogeneous mixing in containment volume

d. Leak location is representative of measured RCS grab sample activity

e. Leak rate is 1 gpm

f. Detector background is 1000 gpm and steady

g. No sampling or measurement errors or interfering activity.

Based on these assumptions, the followi , time would be required to reach the various setpoints.

Concentration	Alarm Setpoint	Time To Alarm
18.1 μCi/cc	7×10^4 cpm	35 hours
18.1 μCi/cc	2000 cpm	28 minutes
0.13 μCi/cc	7×10^4 cpm	*
0.13 μCi/cc	2000 cpm	78 hours

* Will not reach the alarm setpoint due to radioactive nuclide decay rate exceeding the radiation monitor count rate increase

Please note that the above discussions and calculations are related to the gaseous channel of the containment air monitor. Experience has shown that in many cases the particulate channel is much more sensitive than the gaseous channel in detecting a leak. This is because the particulate activity is being concentrated on the monitored particulate filter paper.

However, correlation of the particulate channel reading with an RCS leak rate is essentially impossible. In addition to all of the uncertainties related to the gaseous correlation discussed above, the following significant uncertainties will exist for particulate measurements.

(1) Flash Fraction

The fraction of particulate activity which flashes from water to an airborne form depends on many parameters.

(2) Leak Site Removal

If the leak is into insulation or through packing, a significant fraction of the particulate activity could be removed at the leak site.

(3) Deposition, Plateout, Fallout

Numerous particulate removal mechanisms exist in the containment that are highly dependent on flow patterns.

(4) CS-138, Rb-88

These two particulate daughters of the noble gases Xe-138 and Kr-88 are often the predominate particulate activity. But because of the relatively short half life of both parents and daughters, the concentration of these nuclides is dependent on highly variable parameters of relative percent of Xe-138 and Kr-88 at the leak location and delay time from leak location to monitor location.

(5) Activity Buildup on Filter Sample

The rate of change in count rate is due to both the rate of change of activity in containment from the leak and the rate of build-up of activity on the filter paper. It is difficult to differentiate the contribution of one effect from the other in a dynamic condition.

(6) Radon Daughter Interference

After changing filters it takes some time (approximately 6 hours) for particulate radon daughters, which always exist, to reach an equilibrium count rate.

Given these uncertainties, we do not feel that a simplistic sensitivity calculation is meaningful for the particulate channel. As noted above, however, the particulate channel is important since it can give a more rapid and sensitive indication of changing radiological conditions. Note that at Millstone Unit No. 2, from June - August 1993 (time of 2-CH-442 leakage), the particulate channel did indicate an increase in containment airborne activity, but the gaseous channel did not.

Question 4: Is there any plan to change the design basis of the RMS? For example, if the RG sensitivity cannot be achieved with current RCS activity levels, what about changing the FSAR similar to Unit No. 3? In other words, is the system meeting the design basis of the plant now?

Response 4: FSAR modifications to clarify this issue have been discussed and are being considered. Statements may be added clarifying that these monitors are capable of meeting their design basis of detecting a 1 gpm leak in 1 hour for design basis coolant activity and ideal conditions (e.g., homogeneous mixing), but that many factors such as low coolant activity may render these monitors insensitive to detecting RCS leakage.

Question 5: Does NNECO intend to provide operators with "approximate relationships converting these signals (RM) to units of water flow...to assist the operators in interpreting signals (RG 1.45 page 3, Detector Response Time) and "Procedures for converting various indications to a common leakage equivalent...(RG 1.45, page 4, item 7)?

Response 5: NNECO feels that such guidance could lead to inappropriate actions and thus has no current plans to provide such guidance. Based on the discussion above, such correlations would be subject to significant uncertainty, often nonconservative. For example, such a correlation would be based on measured RCS activity. If the leak was from the charging line, what the operator might think is a 1 (one) gpm leak, could be a 50 gpm leak. It would not be prudent to provide the operator with a false sense of security that he has a valid estimate of the leak rate based on the radiation monitor reading.

The radiation monitor should function solely as a trend indicator. An increasing reading or alarm should alert the operator to put increased priority on quantifying the leakage via other means (e.g., water balance calculations). We are evaluating procedural changes to implement this philosophy.

In fact, one insight from this is that the NRC Staff may want to consider an Information Notice to inform licensees who do provide a radiation monitor to leak rate correlation of the inherent risk in doing so.

Question 6: To be answered by Nuclear Licensing.

RHY/j

cc: W. J. Temple
R. W. Bates
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C. A. Flory
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ATTACHMENT C

List of Automated Work Orders (AWOs)

AWO M2-93-08029, Perform SP-2404AN, Spent Fuel Pool Area Radiation Monitor Functional Test, dated July 14, 1993

AWO M2-93-09552, Perform SP-2410A, Acoustic Valve Monitor Functional Test, dated September 3, 1993

AWO M2-93-08893, Perform SP-2404AN, Spent Fuel Pool Area Radiation Monitor Functional Test, dated August 11, 1993

AWO M2-93-10622, Perform SP-2404AV, RBCCW Liquid Process Monitor Functional Test, dated October 1, 1993

AWO M2-91-09659, Perform SP-2404AS, High Range Stack Radiation Monitor (RM-8168) Calibration, dated May 18, 1993

AWO M2-93-10836, Perform SP-2410A, Acoustic Valve Monitor Functional Test, dated October 10, 1993

AWO M2-03-10955, Perform SP-2403B, ESAS Undervoltage Calibration, dated October 13, 1993

AWO M2-93-10933, Perform SP-2403A, ESAS Bistable Trip and Automatic Test Inserter Test, dated October 13, 19932