1336(1)

June 3, 1999

Mr. R. P. Necci, Vice President
Nuclear Oversight and Regulatory Affairs
c/o Mr. D. A. Smith, Manager - Regulatory Affairs
Northeast Nuclear Energy Company
P.O. Box 128
Waterford, Connecticut 06385

SUBJECT: NRC COMBINED INSPECTION 50-245/99-05; 50-336/99-05; and 50-423/99-05

Dear Mr. Necci:

On April 19, 1999, the NRC completed an inspection at Millstone Units 1, 2, and 3 reactor facilities. The enclosed report presents the results of that inspection.

During the seven week period covered by this inspection period, your conduct of activities at the Millstone facilities was generally characterized by safety-conscious operations, sound engineering and maintenance practices, and careful radiological work controls.

As documented in the enclosed inspection report, the closure of 15 significant items list (SIL) issues at Unit 2 signifies completion of the inspection for the entire Unit 2 SIL. This culminates the substantial NRC inspection effort, governed by the Restart Assessment Plan (RAP), that included 55 restart issues (i.e., 95 individual inspection items). Your rigorous approach and management emphasis upon proper SIL closure have provided for successful completion of this assessment effort. We note that the NRC staff recommendation to allow Unit 2 to restart was contingent upon acceptable resolution of all SIL items. With the closure of the Unit 2 SIL and Restart Assessment Plan requirements, the enclosed inspection report not only documents the results of several significant programmatic inspections, but also marks a transition of Unit 2 from a recovering facility to a plant recommencing critical operations and power ascension activities.

During this inspection period, power operations have been sustained at Unit 3 without incidence of the operational events that have challenged your staff during previous report periods since startup. We continue to observe conservative decision making on the part of the unit management and your operations staff, as exemplified by the staff response to a severe, high-wind storm. It appears that your renewed operational focus is working as intended to minimize challenges and their impact on operations. As has been confirmed by Nuclear Oversight assessments, continued emphasis on your efforts to improve performance in the areas of work control and corrective actions, as well as operations, appears warranted.

Within the area of plant support, we found that you continued to implement effective Radiological Environmental Monitoring and Meteorological Monitoring Programs (REMP and MMP). You demonstrated improvements and effective performance regarding maintenance and calibration of the meteorological instrumentation. Your environmental laboratory effectively analyzed samples and conducted quality assurance and quality control activities to verify and validate program performance.

Based on the results of this inspection, the NRC has determined that 12 Severity Level IV violations of NRC requirements occurred. These violations are being treated as Non-Cited Violations (NCVs), consistent with Appendix C of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violation or severity level of these NCVs , you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with a copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Millstone facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room (PDR).

Sincerely,

ORIGINAL SIGNED BY:

James C. Linville, Director
Millstone Inspection Directorate
Office of the Regional Administrator

Docket Nos. 50-245, 50-336, 50-423

Enclosures:
1. NRC Combined Inspection Report 50-245/99-05; 50-336/99-05; 50-423/99-05
2. Table 1, "Aquatic Environmental Sampling Types and Locations" and Figure 1, "Aquatic Sampling Locations"

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos.:	50-245	50-336	50-423
Report Nos.:	99-05	99-05	99-05
License Nos.:	DPR-21	DPR-65	NPF-49

Licensee: Northeast Nuclear Energy Company
P. O. Box 128
Waterford, CT 06385

Facility: Millstone Nuclear Power Station, Units 1, 2, and 3

Inspection at: Waterford, CT

Dates: March 2, 1999 - April 19, 1999

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Approved by: James C. Linville, Director
Millstone Inspection Directorate, Region I

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EXECUTIVE SUMMARY
Millstone Nuclear Power Station
Combined Inspection 245/99-05; 336/99-05; 423/99-05

Operations

- At Unit 2, the NRC concluded that the licensee's expanded review of approximately 50 systems to identify instances where operating procedures did not reflect final safety analysis report requirements was acceptable and that identified deficiencies were appropriately dispositioned. As a result, Unit 2 Significant Items List No. 9 is closed. (Section U2.O3.2)

- Overall, Unit 3 staff response to the operational challenges, operability concerns, and equipment problems that emerged during this inspection period was adequate; with evidence of conservative decision making by plant management, and appropriate actions and timely corrective measures taken by the operators on shift. (Section U3.O1.1)

- Failure to perform the required sampling during Unit 3 steam generator drain down is a violation of TS. The licensee's corrective actions were timely and acceptable. Therefore, this licensee-identified and corrected violation is being treated as a **non-cited violation (NCV 50-423/99-05-09)**, consistent with Section VII.B.1 of the NRC Enforcement Policy. (Section U3.O8.1)

- The licensee's failure to perform a daily check of a Unit 3 radiation monitor is a violation of technical specifications. The licensee's corrective actions were timely and acceptable. Therefore, this licensee-identified and corrected violation is being treated as a **non-cited violation (NCV 50-423/99-05-10)**, consistent with Section VII.B.1 of the NRC Enforcement Policy. (Section U3.O8.6)

- The historical failure to perform a channel calibration of the Unit 3 hydrogen recombiners is a violation of technical specifications. The licensee's corrective actions were timely and acceptable. Therefore, this licensee-identified and corrected violation is being treated as a **non-cited violation (NCV 50-423/99-05-11)**, consistent with Section VII.B.1 of the NRC Enforcement Policy. (Section U3.O8.7)

- The failure to perform the Unit 3 fuel handling crane limit switch surveillance is a violation of technical specifications. The licensee's corrective actions were timely and acceptable. Therefore, this licensee-identified and corrected violation is being treated as a **non-cited violation (NCV 50-423/99-05-12)**, consistent with Section VII.B.1 of the NRC Enforcement Policy. (Section U3.O8.8)

Maintenance

- At Unit 2, the NRC conducted extensive inspections of the repair activities associated with a leaking shutdown cooling suction valve, which was unisolable from the reactor coolant system (RCS) and was required to remain operable for RCS pressure boundary integrity and for decay heat removal in Operational Mode 5, cold shutdown. The NRC found that there were no regulatory requirements that would prohibit this repair and that the repair could be accomplished safely, without undue risk. The licensee implemented the repair in a controlled manner that maintained operability of the valve throughout the repair activities. The repair stopped the pressure seal leakage. The NRC found that the modification to weld a seal ring between the valve body and bonnet satisfied the American Society of Mechanical Engineers Boiler and Pressure Vessel Code requirements. (Section U2.M1.2)

- At Unit 2, the licensee's review of the failure to perform response time testing of the Foxboro SPEC 200 instrumentation used for the Reactor Protection and Engineered Safeguards Actuation Systems was comprehensive and resulted in the revision and/or development of several surveillance procedures. Subsequent testing verified that the response time of the affected safety-related loops was within the Technical Specification limits. This is a violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control." This Severity Level IV violation is being treated as a Non-Cited Violation (NCV 50-336/99-05-01), consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations which have been entered into the corrective action program. Furthermore, because the above evaluation and resolution of the issue acceptably addressed the NRC concerns regarding root cause and scope of testing, the associated Licensee Event Report 50-336/96-24-00 & 01, Unresolved Item 50-336/96-08-09, and Significant Items List item 47 are closed. (Section U2.M8.2)

- Observed maintenance and surveillance activities were appropriately controlled and performed in accordance with approved procedures or work orders and technical specification requirements. (Section U3.M1.1)

Engineering

- At Unit 2, the licensee's design, evaluation, and implementation of the temporary repair of a "pin-hole" leak of the "A" emergency diesel generator service water supply header spool No. SK4253 was acceptable and in accordance with NRC Generic Letter (GL) 90-05. The piping containing the flaw was operable with Temporary Modification No.2-99-008 until a replacement spool was installed. The licensee installed a fully qualified replacement spool prior to Unit 2 restart. (Section U2.E1.6)

- The Unit 2 Final Safety Analysis Report (FSAR), Section 6.1.4.1.1, "Damage Protection Criteria," specifies the requirements to protect systems and structures from the results of pipe whip or pipe rupture. The failure of the equipment and structures discussed in LER 50-336/97-031-00 to meet the FSAR requirements is a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. However, this violation is identified as a Non-Cited violation (NCV 50-336/99-05-02) in accordance with Section VII.B.1 of the NRC Enforcement Policy because the licensee identified the design deficiencies and took appropriate actions to correct the discrepancies. The HELB questions raised by URI 50-336/97-031-00 were captured by LER 50-336/97-031-00. Hence, URI 50-336/93-19-02, LER 50-336/97-031-00, and Unit 2 Significant Items List No. 19.4 are closed. (Section U2.E8.1)

- At Unit 2, the licensee acceptably addressed the Station Blackout issues identified in the Vectra assessment. Therefore, EEI 50-336/96-201-28, Violation 50-336/02092, and Unit 2 SIL item number 31 are closed. The prepared analyses were reasonable; the calculations detailed, conservative, and in accordance with industry standards. However, the inspector found that dc voltage drop calculations were inadequate in that two incorrect assumptions were identified in shutdown voltage of the safety-related inverters and voltage drop in control cables. This is a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." This concern had limited safety impact because the battery currently has sufficient spare capacity to compensate for the potential deficiency. The licensee initiated action to evaluate the issues. Therefore, this Severity Level IV violation is being treated as a Non-Cited Violation (NCV 50-336/99-05-03), consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into their corrective action program. (Section U2.E8.10)

- At Unit 2, the final safety analysis report Chapter 14 accident analysis for a main steam line break (MSLB) event initiated from low power was inadequate in that it did not consider the effects of auxiliary feedwater flow at the start of the accident which created the potential for peak containment pressure to exceed containment design pressure. The failure to establish an adequate MSLB analysis is a violation of 10CFR50, Appendix B, Criterion III, Design Control. However, the licensee identified this inadequacy and took adequate corrective actions to ensure containment pressure would remain below containment design pressure following a MSLB event. Therefore, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, (NCV 50-336/99-05-04) consistent with Section VII.B.1 of the NRC Enforcement Policy. Licensee Event Report 50-336/97-006-00 and Unit 2 Significant Items List No. 44 are closed. (Section U2.E8.11)

- At Unit 2, the NRC concluded that the licensee effectively addressed the concerns identified in Licensee Event Report (LER) 50-336/97-015-00 & 01, which involved the potential for water hammer and thermally induced overpressurization of isolated piping segments during postulated accident conditions. Therefore, LER 50-336/97-015-00 & 01 and Unit 2 Significant Items List No. 55.2 are closed. The failure of the licensee to consider the potential failure modes of isolated piping segments during the initial system design is a violation of 10CFR50, Appendix B, Criterion III, Design Control. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. (NCV 50-336/99-05-05) (Section U2.E8.12)

- At Unit 2, the licensee's corrective actions adequately addressed LER 50-336/97-19-00 regarding unexpected electro-magnetic interference (EMI) between the Automatic Test Initiation feature of the Engineered Safeguards Actuation System (ESAS) and the timing circuit for the shedding and sequencing of the emergency bus loads. The existence of the EMI signal which, under degraded voltage conditions, could have delayed the shedding and sequencing of the emergency loads on the electrical buses by as much as ten seconds, was the result of inadequate design reviews and/or testing during the 1992 upgrading of the ESAS. This Severity Level IV violation is being treated as a Non-Cited

Violation (NCV 50-336/99-05-06), consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations which have been entered into their corrective action program. Also, LER 50-336/97-019-00 is closed. (Section U2.E8.13)

- At Unit 2, the failure to maintain the main steam and the feedwater systems within the design basis by failing to include required loads in pipe stress and pipe support calculations was a violation of 10CFR50, Appendix B, Criterion III, Design Control. However, the licensee identified these discrepancies with the design basis, and took adequate corrective actions to bring these two systems within the allowable established values in the code of record. Therefore, this licensee identified and corrected violation is being treated as a Non-Cited Violation (NCV 50-336/99-05-07), consistent with Section VII.B.1 of the NRC Enforcement Policy. LER 50-336/97-029-00 & 01 is closed. (Section U2.E8.14)

- At Unit 2, the accident analysis for a loss of normal feedwater (LONF) event was found by the licensee to be inadequate in that inaccurate and non-conservative assumptions were used for the initial steam generator water level and other parameters. This condition was a violation of 10CFR50, Appendix B, Criterion III, Design Control. However, the licensee identified the discrepancies, and took adequate corrective actions which provided an adequate margin to steam generator dryout following a LONF event. Therefore, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, (NCV 50-336/99-05-08) consistent with Section VII.B.1 of the NRC Enforcement Policy. LER 50-336/98-012-00 & 01 and Unit 2 Significant Items List No. 55.5 are closed. (Section U2.E8.16)

- Unit 3 new fuel receipt activities were well controlled and performed by knowledgeable reactor engineering, maintenance, and health physics personnel. Fuel inspections were thorough and nonconformances were appropriately dispositioned. (Section U3.E1.1)

Plant Support

- Offsite Dose Calculation Manual (ODCM) requirements for reporting effluent releases and projected doses to the public were effectively implemented; and, (2) the ODCM contained sufficient specification, information, and instruction to acceptably implement and maintain the radioactive liquid and gaseous effluent control programs. (Section R1.2)

- The radiological environmental monitoring program was effectively implemented in accordance with regulatory requirements. The licensee effectively performed sample collection activities, conducted the land use census, and maintained and calibrated the automatic sampling equipment and analysis equipment according to the appropriate procedures. The procedures were technically correct, but needed some administrative revision to reflect program oversight and implementation responsibilities. (Section R1.3)

- The meteorological monitoring program was effectively maintained and implemented in accordance with regulatory requirements. The licensee's performance with regard to maintaining the meteorological monitoring instrumentation reliable was also effective. The licensee improved meteorological monitoring instrumentation through program ownership and better communication, tracking areas for improvement, and correcting previous problems. (Section R1.4)

- The NRC identified instances of poor contamination control during preparations for Unit 3 refueling outage 6. These observations, coupled with similar, recent nuclear oversight observations, indicate a need for management attention in this area. (Section R1.5)

- The licensee established, implemented, and maintained an effective RMS program with respect to electronic calibrations, radiological calibrations, system reliability, and tracking and trending. (Section R2.1)

- The licensee established, implemented, and maintained an effective ventilation system surveillance program with respect to charcoal adsorption surveillance tests, HEPA mechanical efficiency tests, and air flow rate tests. (Section R2.2)

- The licensee established, implemented, and maintained an effective quality assurance program for the radioactive effluent control program with respect to audit scope and depth, audit team experience, and response to audit findings. The licensee also implemented an effective quality control program to validate measurement results for radioactive effluent samples. (Section R7.1)

- The Safety Assessment Branch (SAB) assumed responsibility to implement the REMP and provided adequate program oversight to meet the requirements specified in the REMODCM. No degradation in program quality or effectiveness was identified. (Section R6.1)

- The most recent audit of the REMP was detailed and thorough and covered every aspect of the REMP. The audit was sufficient to effectively evaluate implementation and effectiveness of the REMP. The recommendations for improvement were appropriate and corrective actions for areas for improvements were appropriate. (Section R7.2)

- The REMP quality assurance program was effectively maintained and implemented in accordance with regulatory requirements. The environmental laboratory continued to implement excellent QA/QC programs for the REMP, provide effective validation of analytical results, and conduct the QA/QC programs in accordance with procedures that reflect industry standards and methods. The programs were capable of ensuring independent checks on precision and accuracy of the measurements of radioactive material in environmental media. (Section R7.3)

- At Unit 2, the inspector performed an on-site review of the licensee's closure package that addressed Licensee Event Report (LER) 50-336/98-21-00. The containment gaseous and particulate radiation monitors (RM 8123 A&B, and RM 8262 A&B) may not be able to detect radioactivity released, due to improper air mixing in the containment, during a Fuel Handling Accident in Containment (FHAIC) and isolate the containment purge system to prevent an unacceptable release to the environment. The cause of this

LER was the failure to reflect design basis assumptions in operating practices. However, this licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-336/99-05-13)** LER 50-336/98-21-00 is **closed**. (Section R8.3)

- At Unit 2, NRC Unresolved Item 50-336/90-18-05 and Unit 2 Significant Items List No. 23.7 were closed. The licensee adequately demonstrated the operation of the PASS. Sample results met the appropriate acceptance criteria and, although the licensee could not consistently meet the total dissolved gas (TDG) acceptance criteria, TDG concentration results were marginally outside the acceptable value. The licensee is continuing to assess the method for retrieving and analyzing a TDG sample for better accuracy. Revised/approved PASS procedures were found to be detailed, technicians were retrained, equipment deficiencies were corrected and the system was repeatedly tested. The licensee adequately demonstrated an Emergency PASS drill and met the time requirement for obtaining post-accident sample results within 3 hours. An unresolved item is being opened to allow further NRC evaluation of the licensee's method for assessing core damage without the use of a TDG analysis and to review the 10CFR50.54(q) evaluation for determining whether or not the procedure change decreased the effectiveness of the E-Plan. (URI 50-336/99-05-14) (Section P8.1)

Report Details

Summary of Unit 2 Status

Unit 2 entered the inspection period in Operational Mode 5, cold shutdown, with the reactor coolant system partially filled. During the inspection period, the licensee completed filling and venting the reactor coolant system and used reactor coolant pump heat to bring the plant to normal operating pressure and temperature in Operational Mode 3, hot standby. The NRC Operational Safety Team Inspection observed the transition into Operational Mode 4, hot shutdown, on March 25, 1999, and the subsequent transition into Operational Mode 3 on March 31, 1999. The Team's observations are documented in NRC Inspection Report 50-336/99-04, dated April 30, 1999. On April 6, 1999, the licensee initiated a plant cooldown to repair a leaking shutdown cooling system suction isolation valve. At the completion of the inspection period, Unit 2 had returned to Operational Mode 5 with repairs to the leaking valve in progress.

The unit was initially shut down on February 20, 1996, to address containment sump screen concerns and has remained shut down to address the problems outlined in the Restart Assessment Plan and a NRC Demand for Information [10 CFR 50.54(f)] letter requiring an assertion by the licensee that future operations will be conducted in accordance with the regulations, the license, and the Final Safety Analysis Report.

U2.I Operations

U2 O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspector conducted frequent reviews of ongoing plant operations, including observations of operator evolutions in the control room; walkdowns of the main control boards; tours of the Unit 2 radiologically controlled area and other buildings housing safety-related equipment; and observations of several management planning and oversight committee meetings.

The inspector observed operational preparations, procedural adherence, and conformance to technical specification requirements during portions of the following evolutions: the establishment of a steam bubble in the pressurizer, plant heatup to normal operating pressure and temperature, and plant cooldown from normal operating temperature and pressure to cold shutdown.

The operators conducted the evolutions described above well. The inspectors noted good communication practices and careful adherence to operating procedures. Enhanced line management oversight of operations and a near-continuous Nuclear Oversight presence in the control room were evident. These actions to improve oversight were consistent with identified corrective actions to address a series of operational events related to the control of plant configuration that occurred earlier this year.

O1.2 Augmented Inspection Coverage During Restart: **(Closed - Unit 2 Significant Items List No. 15)**

Unit 2 Significant Items List No. 15 was created to satisfy the NRC Manual Chapter 0350, "Staff Guidelines for Restart Approval," Checklist Section C.4, which specified that augmented NRC inspection coverage be provided to assess licensee restart and power ascension activities. An inspection plan has been developed that references various inspection procedures that will be utilized to conduct an assessment of licensee performance through sustained observations of the Unit 2 control room and other plant observations. The assessment will begin during the startup from Mode 3, through initial criticality, up to 30% power. Augmented coverage will involve a minimum of 16-hours per day, covering major evolutions and major maintenance and surveillance activities. Based on the development of this restart inspection plan, Unit 2 Significant Items List No. 15 is **closed**.

O1.3 Disposition of Regulatory Issues: **(Closed - Unit 2 Significant Items List No. 17)**

Unit 2 Significant Items List (SIL) No. 17, involves the disposition of regulatory issues that are listed in the NRC Manual Chapter 0350, "Staff Guidelines for Restart Approval," Checklist Sections C.5 and C.6, which included license amendments, exemptions, orders, allegations and 10 CFR 2.206 petitions. Because the Unit 2 SIL was designed to provide a list of all issues that required an NRC inspection prior to restart, Unit 2 SIL 17 was added to ensure that outstanding regulatory issues were specifically screened by the Millstone Restart Assessment Panel to identify issues requiring an onsite inspection. During an April 7, 1999, meeting, Millstone Restart Assessment Panel performed a final screening and determined there were no additional inspection items. Therefore, Unit 2 SIL No. 17 is **closed**.

O1.4 Quality of 10 CFR 50.72 and 50.73 Reports: **(Closed - NRC Manual Chapter 0350 C.1.4.i)**

The NRC assessed licensee performance associated with NRC Manual Chapter C.1.4.i, which involved the quality of 10 CFR 50.72 and 50.73 reports. During the period that Millstone Unit 2 has been shut down, the NRC has performed detailed inspections of numerous licensee event reports. In addition, as the resident inspectors have reviewed condition reports as part of core inspection program which includes a verification that identified issues are appropriately reported to the NRC in accordance with 10 CFR 50.72 and 50.73. Overall, the NRC concluded that Unit 2 has demonstrated the appropriate threshold for reporting items to the NRC and that the quality of licensee event reports has been generally good. Accordingly, NRC Manual Chapter 0350 C.1.4.i is **closed**.

U2 O3 Operations Procedures and Documentation

O3.1 Procedure Upgrade Program: **(Closed - Unit 2 Significant Items List No. 8)**

A number of NRC inspections have been performed to assess Unit 2 Significant Items List No. 8, which involved procedure adequacy and the Procedure Upgrade Program.

The quality of and adherence to procedures had been a chronic problem for all three Millstone units. The need to improve procedure quality was an element in the Improving Station Performance program (circa 1995) and the earlier Performance Enhancement Program (circa 1992). In response to NRC concerns, the licensee developed the Procedure Upgrade Program (PUP) in 1992 to improve station procedure quality on a site-wide basis. The licensee's PUP commitment was included in a letter to the NRC dated June 4, 1992, in which the licensee described its overall Performance Enhancement Program. Because of the licensee's longstanding commitment to complete the PUP and address past procedure adherence and quality problems, the satisfactory performance of the licensee's PUP was identified as a separate issue in the Unit 2 Restart Assessment Plan.

Although various procedure improvement programs had been ongoing since the late 1980s, the licensee committed to improve procedures to reflect industry standards for format and to standardize procedures at all three units in the PUP. As a result of this process, the station document control administrative procedures were developed to apply to the three units.

The NRC performed a series of inspections of the PUP starting in August 1996, and ending in August 1997. These inspections determined that the licensee had met most of their commitments made to the NRC in a June 4, 1992, letter, particularly in standardizing the format of station procedures and reducing the number of higher tiered procedures. The licensee has met their remaining commitments and completed the PUP for Unit 2 on March 10, 1999.

Additional insights regarding procedure quality have been obtained through several NRC Independent Corrective Action Verification Program (ICAVP) inspections. Only several minor problems were identified. In addition, the Operational Safety Team Inspection (OSTI) found operating procedure quality to be good, and in general, operating procedures reviewed were technically sound, with only minor problems identified. In addition, the OSTI found that operators conducted observed evolutions in Mode 4 and Mode 3 (plant non-critical heatup) in compliance with operating procedures. The OSTI also found maintenance and surveillance testing procedure quality and adherence to be acceptable.

These NRC inspections and the licensee's own evaluations indicate that Unit 2 procedures are acceptable for restart. As previously noted, the NRC's inclusion of the PUP as a separate issue in the Unit 2 RAP was to assess the licensee's implementation of this longstanding program. In addition, the staff has also had many opportunities to assess the technical adequacy and quality of the procedures, as well as the licensee's adherence to procedures. There has been a substantial improvement over the past 2 years in this area. Therefore, Unit 2 Significant Items List No. 8 is **closed**.

O3.2 Operating Procedures Consistent with FSAR Description of System Operation; **(Closed - Unit 2 Significant Items List No. 9)**

a. Inspection Scope (92901)

The inspector reviewed the licensee's actions to address Unit 2 Significant Items List (SIL) No. 9 which concerned operating procedures not reflecting final safety analysis report (FSAR) requirements. Following the licensee's Configuration Management Plan (CMP) effort, which was designed to identify FSAR discrepancies, NRC Inspection Reports 50-336/98-202 and 50-336/98-207 documented additional examples of operating procedures not cinsistent with the FSAR.

b. Observations and Findings

In June 1998, the licensee conducted a self-assessment (U2-DE-98-012) which evaluated four systems regarding the adequacy of the FSAR/operating procedure reviews that were conducted as part of the CMP. The licensee's self-assessment identified several additional examples of FSAR/operating procedure discrepancies, which was consistent with the NRC's findings that additional licensee review of this area was warranted.

Based on the results of self-assessment and the NRC's findings, the licensee expanded their review to approximately 50 systems. The review resulted in seven FSAR change requests being initiated and one operating procedure change. The inspector reviewed a number of the condition reports and the associated action assignments that resulted from the expanded review. It was apparent that appropriate corrective actions for the identified deficiencies had been either assigned and completed, or appropriately deferred until after restart.

During a review of specific CMP procedures, the inspector identified that a validation of functional requirements had not been completed as required by U2 PI-7, "Graded System Review." Specifically, the licensee's response to NRC Generic Letter (GL) 96-01, "Testing of Safety-Related Logic Circuits," was not used as the engineering design basis (EDB) information to ensure the functional requirements were validated for the systems identified in NRC GL 96-01, such as the reactor protection system (RPS). However, while the licensee acknowledged that the particular GL 96-01 validation specific to PI-7 did not occur, the inspector determined that the overall impact was minimal because: (1) The CMP program had been completed and the procedures, such as PI-7, are no longer in effect; (2) The PI-7 graded system review packages, at the time of their usage, were considered as the EDB, but have since been replaced by the design basis summaries (DBS), which have been, and continue to be upgraded by the licensee to maintain the LB; (3) Functional requirement validations for the applicable systems addressed in GL 96-01 were completed by the licensee, such that the intent of the PI-7 validation was met.

c. <u>Conclusions</u>

The NRC concluded that the licensee's expanded review of approximately 50 systems to identify instances where operating procedures did not reflect FSAR requirements was acceptable and that identified deficiencies were appropriately dispositioned. As a result, Unit 2 Significant Items List No. 9 is **closed.**

U2 O7 Quality Assurance in Operations

O7.1 <u>Quality Assurance and Oversight Program: **(Closed - Unit 2 Significant Items List No. 11)**</u>

A number of NRC inspections have been performed that addressed Unit 2 Significant Items List No. 11, which involved the Quality Assurance and Oversight Program. Route inspection reports have discussed oversight involvement in specific issues while the 40500 inspection and Operational Safety Team Inspection (OSTI) provided a broader assessment of oversight performance. Oversight and quality assurance was a restart issue due to past ineffective leadership, program implementation, management support, corrective actions and self-assessments, as identified by internal and external audits, including NRC inspections.

The licensee developed a broad-based corrective action program for the deficiencies identified through internal and external assessments of Nuclear Oversight (NOS). Among these actions were: (1) promulgating corporate expectations for NOS; (2) reorganizing and restaffing; (3) developing new hold-point inspection procedures; (4) improving communications between line organizations and NOS, (5) improving the skills of NOS staff in performance-based assessment; and (6) developing the NOS Restart Verification Plan (NORVP) to assess key issues in the recovery process. The NORVP contained approximately 20 key issues that were tracked by NOS to gauge the performance improvements being made by the line organization.

After Unit 3 restarted in June 1998, NOS changed its NORVP assessment process to a Nuclear Oversight Verification Plan (NOVP). This new format incorporated a review of common site programs (e.g., security, emergency planning, and training) along with separate assessments of Unit 3 operations, Unit 2 restart readiness, and Unit 1 maintenance. The full scope of NOS activities, including the NOVP, appeared directed toward focusing Millstone station management attention on the areas impacting Unit 2 restart readiness and the achievement of operational excellence for overall station performance.

The NRC evaluated NOS effectiveness through the routine inspection program as well as the special inspections associated with the closure of SIL items in the Unit 2 RAP. The 40500 Team and Operational Safety Team Inspection (OSTI) examined the area of nuclear oversight and quality assurance. Some of the specific items reviewed included self-assessment programs, various department self-assessments, implementation of the licensee's Quality Assurance program required by 10 CFR 50, Appendix B, and independent oversight organizations such as the Plant Operations Review Committee

(PORC), Station Operations Review Committee (SORC), and Nuclear Safety Assessment Board (NSAB).

During routine and special NRC inspections, the staff confirmed that the licensee has established an effective self-assessment process that contains definitive management expectations regarding the need for performance improvement, an emphasis on self-assessment training, and enhanced procedural controls.

The NRC staff found self-assessment programs have been strengthened, and departmental self-assessments were generally self-critical and constructive. The NOS organization has provided meaningful performance assessments and has effectively identified areas for improvement. The NOS organization was found to be actively involved with the day-to-day operations of Unit 2. The PORC, SORC and NSAB comply with the Unit 2 Technical Specification requirements and were effective in providing plant safety oversight. Therefore, Unit 2 Significant Items List No. 11 is **closed**.

U2.II Maintenance

U2 M1 Conduct of Maintenance

M1.1 General Maintenance Observations

a. Inspection Scope (61726/62707)

During routine plant inspection tours, the inspectors observed, on a random sampling basis, maintenance and surveillance activities to evaluate the propriety of the activities and the functionality of systems and components with respect to technical specifications and other requirements.

b. Observations and Findings

The inspectors reviewed surveillance procedures and maintenance work orders and interviewed licensee field personnel to verify the adequacy of work controls. The inspector observed a portion of activities performed under the following procedures or work orders:

- AWO M2-99-00686 "B" Charging Pump Transfer Switch Replacement
- AWO M2-98-04907 Hot Torque of Bonnet Fasteners for the Shutdown Cooling Suction Header Isolation Valve
- Procedure SP 2601J "C" Charging Pump Discharge Check Valve In-service Test
- Procedure SP 2610B Turbine Driven Auxiliary Feedwater Pump High Flow In-service Test

The inspectors found that the maintenance work was being performed in accordance with approved work orders present at the work site. A review of the work packages found that they were complete with respect to work authorizations, procedures, and inspection requirements. The surveillance tests were executed in accordance with approved procedures.

c. Conclusions

The inspectors concluded that the work performed under the listed maintenance work orders was acceptable. The observed surveillance tests satisfied applicable technical specification surveillance requirements.

M1.2 Repair of Reactor Coolant System to Shutdown Cooling System Suction Isolation Valve

a. Inspection Scope (62707/37551)

The inspector reviewed the licensee's actions to address body-to-bonnet leakage from valve 2-SI-652, the reactor coolant system (RCS) to shutdown cooling (SDC) system suction isolation valve. The inspector observed maintenance activities associated with installation of a welded seal ring and reviewed engineering documents supporting these maintenance activities. The inspector also interviewed individuals in the licensee's operations, maintenance, and engineering departments regarding the valve repair.

b. Observations and Findings

The licensee identified leakage from valve 2-SI-652 shortly after the plant entered Operational Mode 4, Hot Shutdown, and the SDC system was secured. At the time of discovery, the leak rate by the pressure seal of the valve was less than 0.01 gallons-per-minute (gpm). Because the design of the valve causes increased compression of the seal at higher pressure and because previous experience indicated that seal leakage on this type of valve stops at higher pressure, the licensee proceeded with a plant heatup to normal operating pressure and temperature. However, once the plant was at normal operating temperature and pressure, the seal leakage increased from 0.03 gpm to 0.15 gpm, which indicated that the pressure seal was degrading.

On April 6, 1999, operators initiated a plant cooldown to minimize further degradation of the bonnet pressure seal for valve 2-SI-652 and to place the plant in a condition to perform repair of the valve. The valve is not isolable from the RCS because it is located in the 12 inch diameter shutdown cooling suction line just downstream from its intersection with the RCS hot leg piping. Although a gross failure of the valve was not a concern, continued degradation of the pressure seal would lead to a technical specification required cooldown to Operational Mode 5, cold shutdown. After evaluating several options, the licensee proceeded with a plan to repair the valve by welding a seal ring outside the leaking pressure seal while shutdown cooling was in service in Operational Mode 5.

The NRC was concerned with the licensee's decision to attempt a repair of the valve while shutdown cooling was in service because: (1) performance of maintenance activities on a component that is not isolated is generally considered undesirable due to the personnel safety implications; (2) improper performance of maintenance activities on valve 2-SI-652 could result in an unisolable increase in the RCS leak rate; and (3) valve 2-SI-652 would be required to remain in an operable condition throughout the repair activity because the shutdown cooling flow path was being utilized for core decay heat removal. Consequently, this repair activity was the subject of a great deal of NRC inspection by the resident inspectors and regional inspectors, as well as headquarters personnel. Although no regulatory requirement prohibited the licensee from proceeding with the repair while in Operational Mode 5, the NRC evaluated the appropriateness of the licensee's decision not to place the plant in a configuration where valve 2-SI-652 could be removed from service, such as a configuration with the reactor defueled. The NRC determination regarding the acceptability of performing the repair in Operational Mode 5 was based on whether the licensee could demonstrate that the repair activity could be conducted safely, without undue risk.

The safety functions of valve 2-SI-652 in Operational Mode 5 are to maintain RCS pressure boundary integrity and to remain open for shutdown cooling flow. The licensee determined that the components of the valve that provide RCS pressure boundary integrity would be unaffected by the repair activities. However, the valve operator, which holds the valve open, and the bonnet retaining ring, which ensures that pressure boundary components are correctly positioned, would be removed from the valve during the repair activities. To ensure that the pressure boundary components would remain in their correct positions and that the valve would remain open, the licensee developed temporary modifications that would perform the functions of the removed components. The licensee also developed a procedure to control the sequence of installation and removal of the temporary modifications and permanent components such that the valve would remain in an operable state throughout the repair. Additionally, the low power history of the fuel, which resulted from the extended shutdown of Unit 2, significantly increased the time for operators to respond to an unforeseen loss of decay heat removal.

To assess the relative safety of the proposed repair, the inspectors reviewed the temporary modifications, the procedure, and the associated safety evaluations. The temporary modifications were designed to appropriate criteria, and the procedure provided a controlled method for implementing the repair. The inspectors found that the safety evaluation conclusions, which supported implementation of the repair plan, were well justified. The inspectors also reviewed the permanent modification to install the seal ring and found that the modification did not adversely affect the integrity of the RCS pressure boundary nor did the modification violate the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) for RCS pressure boundary components. Based on these inspections, the NRC determined that the license's decision to perform the repair in Operational Mode 5 was acceptable.

The inspectors conducted extended observations of the maintenance activities to repair valve 2-SI-652. The licensee repaired the valve in a controlled manner that maintained the integrity of the valve's pressure boundary and maintained shutdown cooling flow through the valve. The valve leak rate, which was monitored throughout the repair, remained constant. On April 20, 1999, the licensee completed installation of a welded seal ring on valve 2-SI-652 and reassembled the valve. Post-maintenance examination of the valve at normal operating pressure and temperature indicated that the repair was effective in stopping the pressure seal leakage.

c. Conclusions

The NRC conducted extensive inspections of the repair activities associated with a leaking SDC suction valve, which was unisolable from the RCS and was required to remain operable for RCS pressure boundary integrity and for decay heat removal in Operational Mode 5, cold shutdown. The NRC found that there were no regulatory requirements that would prohibit this repair and that the repair could be accomplished safely. The licensee implemented the repair in a controlled manner that maintained operability of the valve throughout the repair activities. The repair stopped the pressure seal leakage. The NRC found that the modification to weld a seal ring between the valve body and bonnet satisfied ASME Code requirements.

U2 M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Violation 50-336/96-08-07: Failure to Perform Surveillance on Certain Containment Isolation Valves

a. Inspection Scope (92901)

The inspector reviewed the licensee's corrective actions to address Violation 50-336/96-08-07.

b. Observations and Findings

Violation 50-336/96-08-07 involved the failure to perform monthly position verifications on containment isolation boundary valves as required by technical specification (TS) 4.6.1.1.a. This violation resulted from the NRC's review of Licensee Event Reports (LERs) 50-336/96-23 and 26. As a result, the licensee: (1) reviewed other TS surveillance procedures for similar conditions; (2) identified other valves that were not included in specific surveillance procedures; (3) subsequently verified valve positions on valves that had not been previously verified; and (4) revised the applicable surveillance procedures to include the required valves.

Licensee corrective actions in response to the violation were subsequently assessed and documented in NRC Inspection Report 50-336/97-02, but remained open pending licensee completion of specific corrective actions. Specifically, the NRC identified that revisions to a surveillance procedure that was the subject of Violation 50-336/96-08-07, lacked adequate guidance to ensure a valve out of position would be identified and corrected during the monthly performances of the procedure. As a result, the licensee submitted a TS amendment that included a detailed discussion regarding the administrative controls that would be implemented in the event one or more specified containment isolation valves were open. The inspector verified that the amendment had been issued, and contained the appropriate administrative controls regarding containment isolation valves. In addition to the TS amendment, the licensee also revised a number of procedures to include appropriate guidance regarding the expected positions of containment isolation valves. Specifically, various containment isolation valves have different positions based on plant conditions. As such, the procedures now contain specific notes that identify expected valve positions and their associated plant condition. The inspector reviewed the procedure revisions and found them to be acceptable.

c. Conclusions

The inspector concluded that the licensee's corrective actions in response to the violation were acceptable, therefore, Violation 50-336/96-08-07 is **closed**.

M8.2 (Closed) URI 50-336/96-08-09 and LER 50-336/96-024-01 & 02; Effects of SPEC 200 Electronics on the Response Time of the Reactor Protection System and the Engineered Safeguards Actuation System; **(Closed - Unit 2 Significant Items List No. 47)**

a. Inspection Scope (92903)

The inspector performed an on-site review of the actions taken by the licensee to address the issues identified in Licensee Event Report (LER) 50-336/96-024 and the questions raised by the NRC during the subsequent review, as described in NRC Inspection Report (IR) 50-336/96-08. The evaluation included a review of the licensee's documents to close the issue, additional applicable documentation, as needed, and interviews of responsible engineering and supervisory personnel.

b. Observations and Findings

On May 7 and May 8, 1996, the licensee informed the NRC that certain sensor channels of the Reactor Protection System (RPS) and Engineered Safeguards Actuation System (ESAS) were inoperable due to the failure to include the response time of the Foxboro SPEC 200 electronics, during the Technical Specification (TS) required surveillance testing of the RPS and ESAS response time. The NRC reviewed the subsequent Licencee Event Report (LER) 50-336/96-024-00 (IR 50-336/96-08) and closed the issue, but questioned: (1) how the effects of the SPEC 200 electronics on the RPS and ESAS response time had been overlooked during the licensee's review of several modifications that installed the SPEC 200 drawers and cabinets; and (2) whether the response time of the entire circuit, including cabling, should be included in the total response time (Unresolved Item 50-336/96-08-09).

To address the first NRC question, the licensee evaluated how the response time testing was performed prior to the installation of the SPEC 200 components. The licensee determined that the originally supplied GE-MAC instrumentation involved analog current loops that, through bistables, generated the signals for the RPS and ESAS control. At that time, the total response time was calculated by adding the response time of individual components in the loop from the sensor to the end device. The response time of interconnecting cables, i.e., the time for the signal to travel between components, was considered negligible.

Apparently, when the changeover from the GE-MAC to the Foxboro SPEC 200 instrumentation began, engineering did question whether the new instrumentation added more time to the system response. However, because the SPEC 200 instrumentation involved state of the art electronic components, the licensee assumed that response time was zero and that the new instrumentation did not add more time to the loop response. It was this incorrect assumption and the fact that the testing method had not effectively changed that caused the licensee to overlook the response time of the new instrumentation.

Regarding the second NRC question, the licensee understood the guidance of IEEE Standard 338 and ISA Standard S67.06 and had, in general, complied with these standards. Therefore, the licensee agreed with the NRC that revision to existing procedures should include response time of passive components, such as cables and terminals.

To address the identified deficiencies the licensee initiated several Adverse Condition Reports (ACRs) to track the required corrective actions, revised the surveillance procedures for both the RPS and the ESAS loops, and completed the required surveillance test in accordance with the new procedures. To ensure that all four trains would be periodically tested, the licensee developed individual procedures for each train.

Following the initial identification of inadequate surveillance testing, the licensee continued the review of the existing process for response time testing and on February 3, 1997, and December 15, 1998, the licensee issued Revisions 1 and 2, respectively, of the subject LER to report additional testing discrepancies identified in the RPS and ESAS as well as in related systems. As had been done with the original LER, the licensee initiated appropriate ACRs, revised or created procedures as needed, and conducted the necessary testing.

The inspector evaluated the corrective actions and the applicable portions of new and revised procedures and discussed with licensee and contract personnel the program, procedures, and methodology for testing the response time of loops and components. The inspector found that, following the original discovery of inadequate time response testing, the licensee had conducted a comprehensive review of the testing program and corrected those areas requiring revision. The inspector also found that the applicable portions of the revised and newly developed procedures acceptably addressed the concern. Lastly, the inspector's review of selected completed tests verified that the response time of the safety-related loops was within the TS-specified limits.

c. <u>Conclusions</u>

The licensee's review of the failure to perform response time testing of the Foxboro SPEC 200 instrumentation used for the Reactor Protection and Engineered Safeguards Actuation Systems was comprehensive and resulted in the revision and/or development of several surveillance procedures. Subsequent testing verified that the response time of the affected safety-related loops was within the Technical Specification limits. The failure to establish an adequate surveillance procedure for performing response time testing is a violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control." This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-05-01)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into their corrective action program. Furthermore, because the above evaluation and resolution of the issue acceptably addressed the NRC concerns regarding root cause and scope of testing, the associated Licensee Event Report 50-336/96-24-00 & 01, Unresolved Item 50-336/96-08-09, and Significant Items List item 47 are **closed**.

M8.3 (Closed) LER 50-336/96-025-00 & 01: Enclosure Building Filtration Actuation Signal/Auxiliary Exhaust Actuation Signal Interlock not Tested Periodically

a. Inspection Scope (37550)

The inspector performed an on-site review of the licensee's corrective actions for LER 50-336/96-025-00 & 01. This LER was one of 17 LERs associated with Escalated Enforcement Item (EEI) 50-336/97-02-12 which involved numerous examples of inadequate surveillance procedures. Although enforcement discretion was exercised for this apparent violation, this EEI, as well as the Unit 2 Significant Items List No. 8.6, has remained open until each of the 17 LERs were dispositioned. Section U2.M8 of this report discusses that the NRC has completed the review of the 17 LERs. The inspection included interviews of responsible engineering personnel, evaluation of the licensee report in accordance with 10 CFR 50.73, as well as the review of applicable licensee evaluations and closure documents.

b. Observations and Findings

As a result of a licensee review of the program for testing safety-related logic circuits in accordance with NRC Generic Letter (GL) 96-01, "Testing of Safety-Related Logic Circuits," the licensee discovered that an interlock required to ensure that the air filtration and exhaust of the enclosure building took precedence over that of the spent fuel pool area, was not being periodically tested.

To address this deficiency the licensee revised the applicable surveillance procedure, SP-2614D, "AEAS [Auxiliary Exhaust Actuation Signal] Operability Verification," to include testing of the subject interlock. Subsequently, the licensee verified, by test, that the interlock was functional and operable. To ensure that both system trains would be periodically tested, the licensee further revised the procedure by developing independent procedures for each train.

The inspector verified that the original as well as the new procedure had been revised to require verification of operability of the interlock. The inspector identified no areas of concern during this review. The inspector also confirmed that the tests performed by the licensee acceptably demonstrated that the interlocks functioned as intended.

c. Conclusions

The surveillance test procedure revisions acceptably addressed the need for periodic operability verification of the auxiliary exhaust actuation signal interlock. In addition, the tests conducted according to the revised procedures confirmed operability of the interlock. Based on the above, LER 50-336/96-025-00 & 01 is **closed**. Because enforcement discretion was previously exercised by the NRC for this apparent violation of the licensee's testing program, no further NRC action is required.

M8.4 (Closed) LER 50-336/96-035-00: Failure to Perform Periodic Surveillance Testing for Interlock Function Associated with the Main Steam Isolation System Function of the Engineered Safeguards Actuation System

a. Inspection Scope (37550)

The inspector performed an on-site review of the licensee's corrective actions for LER 50-336/96-035. This LER was one of 17 LERs associated with Escalated Enforcement Item (EEI) 50-336/97-02-12 which involved numerous examples of inadequate surveillance procedures. Although enforcement discretion was exercised for this apparent violation, this EEI, as well as the Unit 2 Significant Items List No. 8.6, has remained open until each of the 17 LERs were dispositioned. Section U2.M8 of this report discusses that the NRC has completed the review of the 17 LERs. The inspection included interviews of responsible engineering personnel, evaluation of the licensee report in accordance with 10 CFR 50.73, as well as the review of applicable licensee evaluation and closure documents.

b. Observations and Findings

During the continued effort to review the Millstone, Unit 2, program for testing safety-related logic circuits in accordance with NRC Generic Letter 96-01, "Testing of Safety-Related Logic Circuits," the licensee discovered that the functional testing of the Engineered Safeguards Actuation System logic for the steam generator low pressure signal was incomplete in that it did not verify an interlock trip function between the bistables of both steam generator instrument channels. The interlock provides a main steam isolation signal in both ESAS trains in the event of either steam generator low pressure signal.

To address this deficiency, the licensee replaced the applicable surveillance procedure, SP-2402P, with four new procedures, one for each channel (SP2402PA though D) and revised the procedures to include a verification of the functionality of the interlock. Using the new procedures, the licensee later verified, by test, that the interlock was functional and operable. In addition, recognizing that the testing deficiency was the result of human error, the licensee initiated training of responsible engineering and operations personnel regarding the concerns stated in Generic Letter 96-01 and the need for testing all control functions of safety-related components.

The inspector verified that the new procedures had been correctly revised to require verification of operability of the interlock and that the tests performed by the licensee acceptably demonstrated that the interlocks functioned as intended. The inspector also confirmed that the other actions planned by the licensee to address the identified deficiency had been accomplished. The inspector considered the licensee's resolution of the deficiency reasonable and acceptable.

c. Conclusions

The surveillance test procedure revisions properly corrected the licensee-identified deficiencies in the testing of the steam generator low pressure signal in the Engineered Safeguards Actuation System logic. Subsequent tests conducted according to the revised procedures confirmed operability of the interlock. Based on the above, LER 50-336/96-035-00 is **closed**. Because enforcement discretion was previously exercised by the NRC for this apparent violation of the licensee's testing program, no further NRC action is required.

M8.5 (Closed) EEI 50-336/97-02-12: Numerous Inadequate Surveillance Procedures; **(Closed - Unit 2 Significant Items List No. 8.6)**

Escalated Enforcement Item 50-336/97-02-12 was opened to address 17 examples of inadequate surveillance procedures that were discussed in licensee events reports in a six-month period. Although the NRC exercised enforcement discretion for this apparent violation (NRC letter dated April 16, 1998), the NRC performed several inspections of the licensee's corrective actions to address the concern. NRC Inspection Report 50-336/98-212 documented that the licensee's review of all surveillance tests required by technical specifications was found to be comprehensive and well documented. However, EEI 50-336/97-02-12 remained open pending the licensee's completion of the surveillance procedure changes to address the non-conformances that were reported in 17 LERs. During the current inspection period, the NRC inspected and closed the remaining LERs discussed in EEI 50-336/97-02-12. Therefore, EEI 50-336/97-02-12 and Unit 2 Significant Items List No. 8.6 are **closed**.

M8.6 (Closed) LER 50-336/97-007-00: Inadequate Surveillance Procedure for Verifying Operability of Reactor Coolant System (RCS) Vents

a. Inspection Scope (92901)

The inspector performed an on-site inspection of the licensee's corrective actions to address Licensee Event Report 50-336/97-007-00. The licensee identified the failure to meet technical specifications (TS) requirements to verify the operability of the reactor coolant system (RCS) reactor vessel head vent. The surveillance procedure test did not adequately verify flow from the RCS, in that the test method closed the vent piping root valve and used primary make up water vice actual RCS water. This caused a small portion of the piping to be left untested. The inspector reviewed the revised surveillance procedure (OP 2301D) to determine if TS's were satisfied as a result of the changes. This LER was one of 17 LERs associated with Escalated Enforcement Item (EEI)

50-336/97-02-12 which involved numerous examples of inadequate surveillance procedures. Although enforcement discretion was exercised for this apparent violation, this EEI, as well as the Unit 2 Significant Items List No. 8.6, has remained open until each of the 17 LERs were dispositioned. Section U2.M8 of this report discusses that the NRC has completed the review of the 17 LERs.

b. Observations and Findings

The inspector confirmed the surveillance procedure was changed to vent the reactor vessel head, in overlapping stages, in order to collect the water. Otherwise, the water would go to the sparger and eventually leak directly onto the containment floor. The test is written to be performed during the venting of the RCS. The inspector confirmed the testing was completed for the upcoming operating cycle. The inspector noted that the TS requirements were changed to clarify the test prior to the changes to the surveillance procedure.

c. Conclusions

The licensee's corrective actions were timely and acceptable. LER 50-336/97-007-00 is **closed**. Because enforcement discretion was previously exercised by the NRC for this apparent violation of the licensee's testing program, no further NRC action is required.

M8.7 (Closed) LER 50-336/97-008-00: Insufficient Testing of RPS Logic

a. Inspection Scope (37550)

The inspector performed an on-site review of the licensee's corrective actions for LER 50-336/97-008-00. This LER was one of 17 LERs associated with Escalated Enforcement Item (EEI) 50-336/97-02-12 which involved numerous examples of inadequate surveillance procedures. Although enforcement discretion was exercised for this apparent violation, this EEI, as well as the Unit 2 Significant Items List No. 8.6, has remained open until each of the 17 LERs were dispositioned. Section U2.M8 of this report discusses that the NRC has completed the review of the 17 LERs. The inspection included interviews of responsible engineering personnel, evaluation of the licensee report in accordance with 10 CFR 50.73, as well as the review of applicable licensee evaluation and closure documents.

b. Observations and Findings

While reviewing the Millstone, Unit 2, testing program in accordance with NRC Generic Letter (GL) 96-01, "Testing of Safety-Related Logic Circuits," the licensee discovered that two tests in the Reactor Protection System were not being correctly performed. One test did not confirm, by verifying the status of indication lights, that three "K" relays, which control the ladder network for the 2 out of 4 reactor trip logic, operated correctly. The second test removed the electric field rather than the power to the relay and, therefore, did not correctly verify that the relay contacts changed state when the relay was de-energized.

To address this deficiency the licensee revised surveillance procedures SP2401GA through D, "RPS Channel A [through D] Bistable Trip Test," and SP2402PA though D, "Channel A [through D] SPEC 200 Safety Parameter Functional Tests," to: (1) verify the status of the red indicating lamps; and (2) add and remove jumpers to ensure the de-energization and correct operation of the relays. Using the revised procedures, the licensee verified, by test, that the relays were functional and operable. The inspector verified that the new procedures had been properly revised and that the tests performed by the licensee confirmed the adequacy of the relay logic.

c. Conclusions

The surveillance test procedure revisions properly corrected the licensee-identified deficiencies in the testing of the Reactor Protection System circuitry. Subsequent tests, conducted according to the revised procedures, confirmed operability of the circuitry. Based on the above, Licensee Event Report 50-336/97-008-00 is **closed**. Because enforcement discretion was previously exercised by the NRC for this apparent violation of the licensee's testing program, no further NRC action is required.

M8.8 (Closed) LER 50-336/97-009-00: Insufficient ESAS Surveillance Testing (Generic Letter 96-01 Review)

a. Inspection Scope (37550)

The inspector performed an on-site review of the licensee's corrective actions for LER 50-336/97-009-00. This LER was one of 17 LERs associated with Escalated Enforcement Item (EEI) 50-336/97-02-12 which involved numerous examples of inadequate surveillance procedures. Although enforcement discretion was exercised for this apparent violation, this EEI, as well as the Unit 2 Significant Items List No. 8.6, has remained open until each of the 17 LERs were dispositioned. Section U2.M8 of this report discusses that the NRC has completed the review of the 17 LERs. The inspection included interviews of responsible engineering personnel, evaluation of the licensee report in accordance with 10 CFR 50.73, as well as the review of applicable licensee evaluation and closure documents.

b. Observations and Findings

The licensee used two tests to verify monthly the functionality of the Containment Spray Actuation System (CSAS), a subsystem of the Engineered Safeguards Actuation System (ESAS). The first test involved the injection of a signal in the vicinity of the sensor and the verification that the appropriate bistable tripped. To verify the operability of the logic between the bistable and the actuation module, the licensee used a two millisecond pulse from the Automatic Test Injection feature of ESAS. In 1995, a modification of the actuation module that introduced a 30 millisecond delay rendered the two millisecond pulse inadequate for the intended test. This licensee-identified test deficiency was reported on April 24, 1997. Following the original report, the licensee identified several additional test deficiencies related to the ESAS. These new deficiencies were outlined in revision 1 of the LER (97-009-01), dated February 1, 1999.

As with the conditions described in Sections E8.3, 8.4, and 8.5 of this report, upon identification of the deficiencies, the licensee initiated a condition report, evaluated the issue, revised the applicable procedure, and conducted tests to verify that the feature was functional and operable. The inspector reviewed the LER and associated condition reports and confirmed that the procedures had been acceptably revised. The inspector also verified that tests had been conducted to demonstrate operability of the circuits and design features that had not been tested.

c. Conclusions

The surveillance test procedure revisions properly corrected the licensee-identified deficiencies in the testing of the Engineered Safeguards Actuation System circuitry. Subsequent tests, conducted according to the revised procedures, confirmed operability of the circuitry. Based on the above, Licensee Event Report 50-336/97-009-00 is **closed**. Because enforcement discretion was previously exercised by the NRC for this apparent violation of the licensee's testing program, no further NRC action is required.

U2.III Engineering

U2 E1 Conduct of Engineering

E1.1 10 CFR 50.54(f), ICAVP, and the Design Control Process; **(Closed - Unit 2 Significant Items List Nos. 2 and 3)**

A number of NRC inspections have been performed to assess Unit 2 Significant Items List Nos. 2 and 3, which involved concerns with configuration management and the design control process. Each Millstone unit was requested to submit information describing actions taken to ensure that future operations would be conducted in accordance with the terms and conditions of the operating license, the Commission's regulations, and the Final Safety Analysis Report. In a May 21, 1996, letter, the NRC requested the licensee to provide its plan for completing the licensing bases reviews for each unit. On August 14, 1996, the NRC issued a Confirmatory Order requiring the licensee to obtain the services of a third party to conduct an Independent Corrective Action Verification Program (ICAVP) for each unit. Prior to commencing the ICAVP, the licensee completed its own review, the Configuration Management Plan (CMP), to reestablish the design and licensing bases for all of the Unit 2 Maintenance Rule (10 CFR 50.65) Group 1 and Group 2 systems. The subsequent development and implementation of the ICAVP, designed to verify the CMP results, involved an extensive level of effort.

Parsons was selected by the licensee and approved by the NRC to conduct the ICAVP at Unit 2. During an April 14, 1999, Commission meeting, Parsons indicated that it had completed all of the reviews required by the NRC-approved ICAVP Audit Plan and implementing procedures, and the NRC indicated that the ICAVP had been performed satisfactorily at Unit 2. A summary of the NRC staff's ICAVP oversight efforts is provided in SECY-99-109, "Recovery of Millstone Nuclear Power Station, Unit 2," dated April 9,

1999. In a letter dated April 28, 1999, the NRC stated that the ICAVP had been satisfied. Therefore, Unit 2 Significant Items List Nos. 2 and 3 are **closed.**

E1.2 Electrical Equipment Qualification Program: **(Closed - Unit 2 Significant Items List No. 19.1)**

a. Inspection Scope (37551)

The inspector reviewed the overall status of the Unit 2 Electrical Equipment Qualification (EEQ) Program including the licensing commitments, program documentation, relationship to other site programs, safety-related equipment database, and training activities.

b. Observations and Findings

Safety-related electrical equipment for Unit 2 is required to be designed to accommodate the effects of both normal and accident plant environmental conditions. The licensing basis for the qualification of installed equipment includes the NRC DOR Guidelines and IEEE Standard 323-1974, "IEEE Standard for Qualifying Class IE Equipment for Nuclear Power Generating Stations." Qualifications for replacement items are required to meet 10CFR50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants."

EEQ-related topics for Unit 2 are contained in several sections of the Final Safety Analysis Report (FSAR). Other key EEQ-rolated documents include the EEQ Program Manual (Rev.3, 12-19-97), Specification SP-EE-332 (Rev.1, 9-18-98), and Specification SP-EE-352 (Rev.4, 5-30-96). The EEQ Program Manual includes EEQ Program organizational responsibilities and interfaces, technical program requirements, and instructions for preparing various environmental qualification (EQ) related documents. Specification SP-EE-332 contains the environmental parameters for both normal and accident conditions for all EQ zones based on the High Energy Line Break (HELB) assessment of various accident conditions. Specification SP-EE-352 contains the EQ master list (EQML) of all safety-related equipment and the EQ records (EQRs) for various electrical end devices (e.g., solenoid-operated valves) and commodity groups (e.g., terminal blocks and splices). A large number of these EQRs were prepared by personnel who were also involved in the plant walkdown of all installed safety-related equipment. The EQRs were then reviewed to ensure their quality and compatibility with the Unit 2 specifications.

There are 94 EQRs, which represent about 577 safety-related equipment items (i.e., end devices and commodities), that are currently installed in Unit 2. These 94 EQRs are based on about 15 to 20 generic Test Report Assessments (TRAs). About nine of these EQRs were originally qualified to the DOR guidelines and the remaining ones are qualified to 10CFR50.49 requirements. The nine DOR-qualified items include some older cables and motors which are no longer available from the manufacturer. At the time of this inspection, the EQML was updated and validated to include all electrical safety-related equipment identified by the Safety Functional Requirements (SFR).

The inspector reviewed several EQRs associated with solenoid-operated valves (SOVs) for accuracy and completeness. The SOV circuit diagrams in several of these SOVs revealed that the field walk-down information was not incorporated properly into the line diagrams in the EQRs. The inspector discussed this concern with the licensee who stated that the original design change requests (DCRs), work orders (WOs) and design change notices (DCNs) for these components were completed and the circuit diagrams included in these packages reflected the actual field conditions that were determined from the field-walkdowns. The licensee was aware that the line diagrams in the EQRs had not all been updated but considered this to be an administrative task that could be deferred until after startup. Over 40 condition reports have been issued that document eight categories of administrative deficiencies associated with EQRs. The licensee has reviewed each of these eight categories and determined that this work could be deferred because these administrative deficiencies have no effect on the environmental qualification of any safety-related equipment. The deficiencies are scheduled to be corrected by October 2, 1999. The inspector reviewed the eight categories of administrative deficiencies and found the licensee's basis for deferral to be acceptable.

Each EQR includes an engineering assessment of the actual plant environment during the test conditions, and identifies the configuration, maintenance, and replacement items necessary to ensure equipment performance during tested conditions. The inspector reviewed a sample of the EQR documentation and found it to be technically sound. The inspector found the current EEQ program for Unit 2 is a significant improvement over the prior program.

In accordance with Work Planning Procedure (WP 28001, Rev.1), the licensee has design control requirements which adequately control the interfaces among the various EEQ-related programs. The Design Engineering Division has a dedicated staff to provide the technical expertise related to EEQ. Although the work planning division sent staff members to attend the Electric Power Research Institute (EPRI) course on EEQ last year, in general, EEQ training for departments having EEQ responsibilities (i.e., maintenance, quality control, work planning, procurement, management personnel) is accomplished through informal training courses. The Training Department, in conjunction with Engineering, has plans to develop job-specific training modules for various departments (A/R No. 99002769-01, due May 26, 1999) and to establish program familiarization courses (A/R No. 97029600-07, due August 15, 1999). The inspector found this to be acceptable.

The inspector selected various components in the field and verified the field configurations of several SOVs and pump-motor assemblies. All were consistent with configurations documented in corresponding EQRs.

c. <u>Conclusions</u>

After reviewing the various elements of the EEQ program at Unit 2, the inspector concluded that the revised program documents were acceptable and were being adequately implemented. In addition, the licensee provided an adequate basis for deferring the disposition of the EEQ-related condition reports that remained open. Unit 2 Significant Items List No. 19.1 is **closed**.

E1.3 High Energy Line Break Program Evaluation; **(Closed - Unit 2 Significant Items List No. 19.2)**

a. Inspection Scope (37551)

The inspector reviewed the overall status of the Unit 2 High Energy Line Break (HELB) Program, including the licensing commitments, internal self-assessment findings, program documentation, relationship to other site programs, safe shutdown assessment, equipment database, and training activities.

b. Observations and Findings

Safety-related equipment must be designed for the consequences of High Energy Line Break (HELB) conditions as required by Appendix A to 10CFR50, General Design Criteria 4 (GDC 4), "Environmental and Missile Design Bases." A high-energy system is defined as one where either the maximum operating temperature exceeds 200 degrees Fahrenheit or the maximum operating pressure exceeds 275 psig.

The inspector reviewed the HELB documentation for the pipe rupture analysis criteria outside the containment given in the Unit 2 HELB Design Specification SP-M2-ME-003, Rev.1 and for the high energy line reference drawings and break locations given in HELBDRGS-1411M2, Rev. 0. Both documents were found to be comprehensive and complete.

In September 1994, the licensee initiated a phased approach to the resolution of HELB issues associated with *Outside Containment* and implemented the HELB Reconstitution Program. This involved assessments of 10,969 HELB interactions in 36 HELB areas, reanalysis of high energy lines, and establishment of safe shutdown paths for each HELB event. As a result, numerous design modifications have been made to address HELB deficiencies including the installation of new jet shields and blowout panels, reconfiguration of pipe supports to eliminate break locations, replacement of doors/door seals and penetration seals, and relocation of safety equipment. The calculations relating to these HELB Reconstitution Program upgrades are documented in HELBASIS-1302M2, Rev.3.

The licensee has also completed the HELB assessment of systems *Inside Containment*. As a result, several design changes were implemented including a layout modification of the sample line of the steam generator blowdown system, further analysis of the pressurizer surge line, and some other minor design changes.

The licensee conducted an engineering self-assessment in January 1998. This involved an engineering walk-down of three HELB areas and compared break locations and target interactions with the basis HELB calculations on file. The inspector found that the identified problems were acceptably corrected.

According to the Design Control Manual (Chapter 3, Rev. 6 ch 11, "Design Changes") the licensee has the necessary design control requirements to ensure that any future design modifications involving HELB equipment or area will be properly screened for engineering evaluation. The licensee has also developed and implemented a site-wide training program and persons from various organizations associated with HELB design considerations are required to attend this training. The inspector reviewed the training materials and found them acceptable.

c. Conclusions

After reviewing the various elements of the HELB program at Unit 2, the NRC concluded that the revised program documents were acceptable and were being adequately implemented. The licensee's efforts were extensive in evaluating systems against the HELB pipe rupture analysis criteria and performing necessary modifications to restore compliance with HELB requirements. Unit 2 Significant Items List No. 19.2 is **closed**.

E1.4 Service Water Operational Performance Inspection Followup: **(Closed - Unit 2 Significant Items List No. 51)**

a. Inspection Scope (37551)

The licensee performed a Service Water Operational Performance Inspection (SWSOPI) self-assessment at Millstone Unit 2 in 1995. The self-assessment was observed by NRC inspectors which was documented in Inspection Report 50-336/95-29, dated April 23, 1996. At the time of report issuance, of the original 166 questions/concerns issued, thirty-eight (38) concerns remained open. Additionally, five (5) issues requiring follow-up action were identified in the report text for a total for forty-three (43) items. To date, thirty (30) of the 43 items have been completed. The inspector reviewed all 43 items to determine the acceptability of completed items, to determine the acceptability of the remaining activities identified to complete the remaining 13 open items, and the acceptability of deferring completion of some items until after restart.

b. Observations and Findings

The inspector reviewed the SWSOPI Closure Book for the 43 items. The Closure Book provides the status and supporting documentation for each item including a description of the issue, current status, actions taken to date to correct the issue and prevent recurrence, and actions remaining to close out the SWSOPI open item.

Based on a review of the documents associated with the 30 closed items, the inspector found that the issues identified by the SWSOPI self-assessment were properly described, entered into the licensee's corrective action program, and evaluated. The corrective actions taken to correct the deficiencies and to prevent recurrence are adequate. The inspector observed that program and procedure modifications were made as required to provide the necessary guidance for preventive maintenance, surveillance and inspection of the service water system to prevent recurring problems.

The inspector reviewed the documents associated with the 13 items currently remaining open. Substantial progress has been made on all of the open items with all physical work complete. Seven of the 13 open items (81, 117, 129, 142, 143, 144 & 155) will close when SWSOPI Item 82 closes, which is not scheduled until the next refueling outage. Actions remaining to complete the seven items include tracking thermal performance of heat exchangers, finalizing and implementing service water system piping and component inspection programs and testing the reactor building closed cooling water (RBCCW) heat exchangers. The inspector observed portions of the vital chiller test which was successfully completed during this inspection. The RBCCW testing is not scheduled until the next refueling outage when sufficient plant heat will be generated to run the test.

During walkdowns of the plant with the service water system engineer, the inspector observed that the new sodium hypochlorite system is installed (an unnumbered SWSOPI item.) This system is scheduled to be tested and placed in service prior to startup. Additionally, the inspector walked down Item 8 (Appendix R separation for service water pumps and strainers) which was closed during this inspection. The remaining five items (96, 97, 138, 151 & 166) require document changes to complete. Based on a review by the inspector, all open items being deferred are scheduled for closure during or before the next refueling outage.

c. Conclusion

All physical work required to complete the open SWSOPI items has been completed. The remaining heat exchanger testing, thermal performance monitoring, and documentation changes scheduled for closure after startup will not adversely impact the safe and proper operation of the plant and have an acceptable basis for deferral. The NRC found that the items identified as closed were satisfactorily completed. Therefore, Unit 2 Significant Items List No. 51 is **closed**.

E1.5 Service Water System Temporary Leak Repair

a. Inspection Scope

The inspector reviewed the temporary repair of a "pin-hole" leak of the "A" emergency diesel generator (EDG) code class 3 service water supply header spool No. SK4253.

b. Observations and Findings

The inspector reviewed Temporary Modification Index Number 2-99-008 that stated a "pin-hole" leak was discovered during Mode 4 in the "A" EDG service water supply header spool No. SK4253. The plant entered a 72 hour action statement, for Technical Specification 3.8.11 after service water to the "A" EDG was isolated to stop the leak. A temporary patch was installed to allow service water to be restored and the action statement to be exited while a replacement spool was fabricated. The inspector noted that the "pin-hole" leak was located in the "crotch" of the spool, and was covered with a black rubber patch (flood gate door material) held in place with stainless steel straps.

The inspector reviewed "Technical Evaluation for Operability of Service Water Supply to "A" Diesel Line 8 JGD-4, TE No. M2-EV-99-0078. The evaluation found that the cause of the "pin-hole" leak was local loss of epoxy lining that allowed the steel pipe to be exposed to the salt water, after which erosion-corrosion proceeded through the pipe wall. Ultrasonic pipe wall thickness tests were conducted to define the extent of pipe wall thinning. The results of these tests were used in calculations, in accordance with NRC Generic Letter (GL) 90-05, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping," flaw evaluation methods, that confirmed the structural adequacy of the reduced-wall-section pipe. Predictions of wall thickness thinning indicated that the structural adequacy would be sustained until the replacement pipe could be installed. The licensee installed a fully qualified replacement spool prior to Unit 2 restart.

c. Conclusion

The licensee's design, evaluation, and implementation of the temporary repair of a "pin-hole" leak of the "A" EDG service water supply header spool No. SK4253 was acceptable and in accordance with NRC GL 90-05. The piping containing the flaw was operable with Temporary Modification No.2-99-008 installed until a replacement spool was installed. The licensee installed a fully qualified replacement spool prior to Unit 2 restart.

U2 E8 Miscellaneous Engineering Issues

E8.1 (Closed) URI 50-336/93-19-02 & LER 50-336/97-031-00: Potential Effects of High Energy Line Break on Safety-Related Equipment Located Outside Containment; **(Closed - Unit 2 Significant Items List No. 19.4)**

a. Inspection Scope (92903)

The inspector reviewed the licensee's disposition of Unresolved Item (URI) 50-336/93-19-02 which involved the potential impact of a high energy line break (HELB) on the auxiliary feedwater (AFW) system suction piping in the turbine building. The inspector also performed an on-site inspection of the licensee's corrective actions taken to address Licensee Event Report (LER) 50-336/97-031-00 which involved HELB issues that could affect safety-related equipment outside containment.

b. Observation and Findings

During NRC's inspections in 1993 of the AFW System suction piping operability, the licensee was not able to determine if piping in the Condensate Storage Tank (CST) pipe trench had been included in the original HELB design for Unit 2. Later it was determined that two high energy lines not included in the original HELB design were 3-HBD-152 (auxiliary steam to turbine area unit heaters and heat exchangers X-46 & X-168) and 10-GBD-24 (condensate from air ejectors to condensate surge tank). It was also noted at the time that a short-term licensee mini-review performed in 1990 left four other issues in the turbine building unanswered. These issues were associated with HELB concerns relating to the Dc switchgear chillers, AFW control valves, the main control room, and the AFW pump room. The recent HELB reconstitution effort by the licensee revealed several other design deficiencies at various locations in the plant. As a result, the licensee issued the LER 50-336/97-031-00 in 1997. The inspector reviewed the design change documentation for all of these HELB issues associated with areas outside the containment and selected the five HELB issues identified during the mini-review in 1990 and the inspections in 1993 for a more detailed review.

In September 1994, the licensee initiated a phased approach to resolve all HELB issues associated with safety-related equipment located outside the Unit 2 containment. In 1998, the licensee also completed a similar program for the inside containment equipment. This HELB reconstitution effort included establishing plant shutdown modes, pipe rupture criteria, safe shutdown paths, and an equipment list. The high energy lines were then defined and interactions with safety-related equipment were evaluated. Unacceptable interactions were further assessed for acceptability considering system level conditions, generic calculations, pipe stress analysis, and other approaches (e.g., equipment qualification and structural adequacy). For outside containment areas, several plant modifications resulted from this reconstitution effort including the installation of two jet shields, design changes of doors, installation of blowout panels, sealing of penetrations between rooms and modifying pipe supports to eliminate breaks

Calculation No. TRENCHES-1414M2, Rev. 0 documents the disposition of the HELB interactions within the CST pipe trench. The CST pipe trench runs below grade from the northeast comer of the turbine building to the CST and the condensate surge tank. The trench is sealed at the turbine wall and is covered with grating inside the turbine building. Two high energy lines, 10-GBD-24 and 3-HBD-152, inside the CST trench were evaluated for thirteen specific HELB interactions and were resolved based on engineering criteria developed for HELB conditions (HELBASIS-1302M2, Rev. 3). This resulted in no design changes in the trench. The inspector found the licensee's evaluation of the CST pipe trench to be acceptable.

The following discussions relate to the inspector's review of the four HELB issues from the licensee's 1990 mini-review. DC switchgear chillers X-169A & X-169B were not originally qualified for a harsh environment considering all plausible HELB scenarios. However, operating procedure OP 2315D, "Vital Electrical Switchgear Room Cooling Systems," and Fire Protection Procedure SFP18, "Establishing Ventilation for East and West 480 VAC and 125 VDc Switchgear Rooms," provide compensatory measures for establishing temporary ventilation to the Dc switchgear rooms and maintaining conditions below their design temperature during a loss of ventilation and/or cooling. The inspector found these compensatory measures acceptable.

Calculation No. TBMISC-1278M2, Rev. 5 documents the disposition of the HELB interactions within the turbine building miscellaneous area at elevation 14'-6", including the feedwater vital electrical systems and chillers on the floor. One of the dispositions involved installing pipe jet shields on auxiliary steam system pipe10-HBD-184 (EWR M2-98099 and MMOD M2-98076), which protects: the turbine building south wall (block wall 8.29 in Dwg. 25203-24093), the access control ventilation ducting (common to both areas) and turbine building HELB Door 203-14-009. These components separate the corridor between the Unit 1 and Unit 2 turbine building, and breaching of this boundary would allow steam from a Unit 2 HELB to enter vital switchgear rooms in Units 1 and 2. The inspector performed a walkdown of the area and found the licensee's corrective actions acceptable.

The AFW control valves 2-FW-43A/B are not qualified for a harsh environment. However, the solenoid valves (HV-5276/5279) and limit switches (ZS276/5279) associated with these air-operated valves (AOVs) are qualified for harsh environment as documented in EQRs 109-01, 109-02, 114-01. The qualification of these electrical devices ensures that the valve operators can be vented allowing the valves to fail-open. The back-up air to the AFW regulating valves has also been upgraded to safety-related. This will allow isolation of an affected steam generator following a main steam line break, if the normal non-QA air-supply is unavailable. The licensee has also evaluated the mechanical components to assure that the stem movement will not seize at HELB temperatures and thus, the AOVs will "fail open" as required for safety. In addition, the licensee has environmentally qualified the cross-tie motor-operated valve (MOV), 2-FW-44, to ensure it can function under the accident conditions. With both AOVs in the fail-open position, this MOV can be closed within 10 minutes following a turbine building HELB to isolate the affected steam generator. The inspector found these design changes acceptable.

The control rooms for Unit 1 and Unit 2 and the Dc switchgear rooms are located south of the column 16 block walls. The licensee established the HELB boundary with Unit 1 at column line 16, consisting of block walls, doors, and penetrations (Dwg. 25203-27013, Rev.19). These block walls and doors were originally designed for a differential pressure of 0.5 psid and temperature of 195 °F. The recent HELB calculations indicated that these design limits could be exceeded during a HELB event in the turbine building. The analysis also showed that additional venting would be necessary to relieve pressure in the turbine building. To address this, the licensee provided additional venting area to allow existing interior panels on east side wall to blow out when the pressure in the turbine building reaches 0.35 psid (EASTWALL-02396C2). Double door 203-14-009 was replaced with a HELB door qualified to withstand HELB pressure inside the turbine building. Other components (i.e., a ccess control area air conditioning ducts) penetrating the column line 16 block walls were evaluated to ensure that steam from the Unit 2 turbine building would not infiltrate the Unit 1 area during a HELB in the turbine building. The inspector reviewed all pertinent documents and performed a walkdown of the turbine building to verify the structural modifications. Since Unit 1 is no longer in operation, the licensee's design changes to maintain the block walls on the column line 16 as the HELB boundary for the Unit 2 turbine building are found acceptable.

The AFW pump room containing the turbine-driven AFW pump (TDAFWP) has a removable hatch in the ceiling to prevent over pressurization of the room during a HELB within the pump room. Minor modification (MMOD) M2-98068 provided the required opening area for venting the HELB differential pressure and modified the hatch to provide an unobstructed flow path for the venting steam. In addition, Fan F-158, which currently provides ventilation inside the room for personal habitability concerns, could draw high temperature, high humidity air from the turbine building floor above into the room during an HELB accident anywhere in the turbine building. The fan itself is a non-safety item and is not credited for any accident mitigation. However, MMOD M2-98103 installed a QA category I temperature switch to trip the fan when the temperature of the turbine building reaches 120°F (the normal maximum area temperature of the turbine building being 110 of). The inspector reviewed the documentation and inspected the design modifications, and found that the licensee has taken appropriate corrective actions.

All of the individual issues verified by the inspector were associated with the turbine building. Similar HELB assessments and design modifications were performed by the licensee for the safety-related equipment located in auxiliary building, enclosure building, and other buildings outside the containment. The documentation indicated that the licensee has taken appropriate corrective actions to mitigate deficiencies identified by the HELB evaluation of areas in these buildings.

c. Conclusions

The Unit 2 Final Safety Analysis Report (FSAR), Section 6.1.4.1.1, "Damage Protection Criteria," specifies the requirements to protect systems and structures from the results of pipe whip or pipe rupture. The failure of the equipment and structures discussed in LER 50-336/97-031-00 to meet the FSAR requirements is considered a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. However, this violation is identified as a **Non-Cited violation (NCV 50-336/99-05-02)** in accordance with Section VII.B.1 of the NRC Enforcement Policy because the licensee identified the design deficiencies and took appropriate actions to correct the discrepancies. The HELB questions raised by URI 50-336/97-031-00 were captured by LER 50-336/97-031-00. Hence, URI 50-336/93-19-02, LER 50-336/97-031-00, and Unit 2 Significant Items List No. 19.4 are **closed**.

E8.2 (Closed) IFI 50-336/95-01-01: Complete Load Sensitive Behavior and Stem Friction Coefficient Analyses and Justify Non-dynamically Tested MOV Valve Factors - **(Closed - Unit 2 Significant Items List No. 20.1)**

a. Inspection Scope (92903)

NRC Inspection Report 50-336/98-04 described that the remaining licensee actions needed to close Unit 2 Significant Items List No. 20.1 (Inspector Followup Item 50-336/95-01-01) were to perform diagnostic tests of certain motor-operated valves (MOVs) to verify that design assumptions in the Generic Letter (GL) 89-10 MOV testing and surveillance program pertaining to valve factor, rate of loading, and stem friction coefficient were bounding. Specifically, the licensee committed to: (1) dynamically test valves 2-MS-201, 2-MS-202, and 2-FW-44 to verify rate of loading and stem coefficient of friction; (2) statically test feedwater block valves 2-FW-38A, 2-FW-42A, and 2-FW-42B to verify stem coefficients; and (3) dynamically test turbine driven auxiliary feedwater pump trip/throttle valve 2-MS-464 to verify that the valve factor was less than 1.1. The inspector performed an in-office review of the licensee's actions concerning these valves.

b. Observations and Findings

The licensee originally planned to verify through dynamic testing that actual stem friction coefficients and rate of loading were less than the GL 89-10 program design limits. Subsequently, the existing SMB-000-5 motor-actuators were replaced with larger SMB-00-15 motor-actuators, considerably increasing the valves' capabilities. Revised calculations show margins of 20-30% in the open direction and 200% in the closed direction using bounding assumptions of 32% rate of loading and a 0.2 stem coefficient of friction against thrust requirements derived from the Electric Power Research Institute's performance prediction methodology. The inspector concluded that dynamic testing of these valves was not needed to demonstrate design basis capability.

The results of a dynamic test of valve 2-FW-44 were documented in Attachment A-15 of calculation 89-078-02666M2, "MP2 MOV Static and Dynamic Test Data Analysis." The valve was tested at approximately 91% of its design differential pressure. The measured rate of loading was 4.16% and the stem friction coefficients (0.163 open/0.154 close), adjusted for uncertainties and instrument errors, were well below the design limit of 0.2. The test adequately demonstrated the design basis capability of this valve.

The adjusted, measured static stem friction coefficients of valves 2-FW-38A, 2-FW-42A, and 2-FW-42B were contained in Attachments B-1, B-2, and B-3 of calculation 89-078-02666M2. The measured coefficients were 0.08, 0.108, and 0.117 versus the design limits of 0.191, 0.184, and 0.189, respectively. The diagnostic test traces showed no operational anomalies.

The licensee dynamically tested valve 2-MS-464 on March 31, 1999. Due to a malfunction of the strain gage, direct stem thrust data was not obtained during the test and a valve factor could not be calculated. However, the licensee was able to determine stem thrust indirectly from measured spring pack deflection using a stem friction coefficient derived from statistical analysis of globe valve test data at Millstone 3. Corrected for uncertainties, the thrust and torque capability design margins of this valve were acceptable. The licensee plans to conduct an additional dynamic test following the next scheduled refueling outage and is being tracked by Action Request 98017292-04.

c. Conclusions

The NRC concluded that the confirmatory tests performed by the licensee were adequate. Unit 2 Significant Items List No. 20.1 and Inspector Followup Item 50-336/95-01-01 are **closed**.

E8.3 <u>(Closed) Unresolved Item 50-336/96-01-05: Containment Hydrogen Monitors and Post Accident Sampling System Inoperable; **(Closed - Unit 2 Significant Items List No. 23.5)**</u>

a. <u>Inspection Scope (92903)</u>

The inspector reviewed licensee resolution of Unresolved Item (URI) 50-336/96-01-05 related to Unit 2 post accident sampling system (PASS), hydrogen monitoring system, and radiation monitoring system operability following a loss-of-coolant accident (LOCA). The inspector reviewed the licensee modified hydrogen monitoring system components that were installed in response to these concerns, and walked-down the modified system.

b. <u>Observations and Findings</u>

URI 50-336/96-01-05 involved eight concerns of NRC associated with the operability, design basis and, licensing basis of the hydrogen monitors and PASS. This URI was dispositioned from an enforcement perspective in NRC Inspection Report 50-336/96-08, which discussed the first two of the eight issues and created Escalated Enforcement Items (EEIs) 50-336/96-08-11, 50-336/96-08-12, and 50-336/96-08-13. These EEIs, and the resulting violations, are discussed later in this inspection report. Although the no enforcement action was taken on the remaining six concerns, URI 50-336/96-01-05 remained open to ensure that design changes associated with the hydrogen monitors and PASS adequately addressed the six concerns. The licensee's resolution of the concerns discussed in URI 50-336/96-01-05 is as follows:

(1)&(2) As stated above, the first two of the eight concerns are addressed by EEIs 50-336/96-08-11, 50-336/96-08-12, and 50-336/96-08-13.

(3) <u>Concern</u>: Preventive maintenance and surveillance activities on the hydrogen monitors are necessary to ensure that equipment is properly adjusted, calibrated, and maintained.
<u>Resolution</u>: Surveillance procedure SP2403CA, "Hydrogen Analyzer Calibration," and procedure SP2403CC, "Hydrogen Analyzer Functional Test," were revised to support the new hydrogen analyzer design. The inspector found procedures were written based on the manufacturer's recommendations and technical specification requirements to ensure appropriate calibration and functional procedures have been issued and maintenance procedures are being developed.

(4) <u>Concern</u>: The ability of the hydrogen monitors to satisfy the single failure criteria was challenged when a jumper was required to re-power valves to place hydrogen monitors in service.
<u>Resolution</u>: The inspector found the single failure criteria issue resolved through modification of isolation valve power supplies. This modification provides single failure protection following all accident scenarios by changing the power

source for the analyzer's suction outboard containment valves to allow operation should a loss of a Dc bus occur.

(5) Concern: Modifications associated with the hydrogen monitor stream 1 blowout plugs.
Resolution: The licensee determined that the blow-out plug is not required for plant operation with the modified hydrogen monitoring system. Dome sampling points are not required, and the hydrogen sampling lines have been cut and capped on both sides of the containment penetrations.

(6) Concern: The ability of the hydrogen monitors and PASS to properly function with condensate accumulation in the sample line tubing is necessary.
Resolution: The inspector found that the tubing lines have been designed such that accumulation of condensate is not probable, and the increased pump power is sufficient to prevent accumulations. Furthermore, should accumulation occur, the hydrogen monitor has been designed such that a water slug will not damage the detector element as it is swept through the line. The replaced hydrogen monitor sample pump will be used as the motive force for the containment air PASS, and will function with condensate accumulation in the sample line tubing.

(7) Concern: The failure to test safety-related systems in a manner that duplicates, as close as practical, the post-accident conditions was an important concern.
Resolution: The inspector found that a test procedure has been developed that duplicates as close as practical, the containment operating environmental conditions. The testing procedure duplicates the steps taken by the operator following an accident and demonstrates accurate sampling at normal operating conditions.

(8) Concern: The acceptability of the sample line taking suction directly from the containment atmosphere, which is contrary to the licensee's commitment regarding NUREG 0737, "TMI Action Plan Requirements."
Resolution: The inspector noted re-orientation of the sample points directly to the containment atmosphere and has provided documentation of the acceptability of the sampling location and design in providing a representative sample of the containment atmospheric conditions.

c. Conclusions

The NRC determined that the licensee has adequately resolved the outstanding concerns associated with URI 50-336/96-01-05 through replacement of hydrogen monitoring equipment and improvement of the system design. Performance testing of the completed system under realistic simulation of operating conditions was established. URI 50-336/96-01-05 and Unit 2 Significant Items List No. 23.5 are **closed**.

E8.4 (Closed) EEI 50-336/96-06-12 and VIO 50-336/02082: Electrical Equipment Qualification of Solenoid Operated Valves Inside Containment **(Closed - Unit 2 Significant Items List No. 19.5)**

a. Inspection Scope (92903)

The inspector reviewed the licensee's corrective actions taken to address Escalated Enforcement Item (EEI) 50-336/96-06-12 and Violation 50-336/02082.

b. Observation and Findings

EEI 50-336/96-06-12 involved the failure to adequately establish the environmental qualification of the connectors for the seven solenoid operated valves (SOVs) (2-EB-88S, 89S, 91S, & 100S; and 2-CH-517S, 518S, & 519S) discussed in LER 50-336/96-19-00. The seven SOVs are containment isolation valves located inside containment. The Electrical Equipment Qualification (EEQ) Program had previously assumed that these SOV circuits function for containment isolation only. In 1996, an engineering review of the safety functional requirements (SFR) revealed that these valves were required to be reopened to perform a post-accident sampling function. This resulted in an unqualified configuration of the SOV circuits since they lacked a qualified environmental seal and pigtail to field cable termination for energized operation in the accident environment.

As corrective actions, the licensee added an environmentally qualified seal on each of the solenoid housings, replaced the existing short "pig tail" coils with longer wiring, and replaced the existing "Ideal Set Screw" terminations with qualified "Raychem" splices per DCR M2-98-96063. The qualification report, EQR 114-01, provides each SOV circuit configuration from the SOV unit to the control panel, which is located outside the containment in mild environment, and summarizes all sub-components that are part of the circuit. In addition, the licensee performed a review of all SOV circuit configurations in Unit 2 to identify and resolve qualification deficiencies. Engineering Evaluation M2-EV-970041, Rev.2 documents the review of SOVs outside containment Engineering Evaluation M2-EV-970057, Rev.1, contains SOVs inside containment. Six SOVs located outside containment and 7 SOVs inside containment required design modifications to install EEQ-qualified terminations and seals. Three other SOVs inside containment required the replacement of qualified seals.

The licensee's Safety Analyses Branch completed the SFRs and transmitted the report to EEQ Engineering, as Engineering Evaluation M2-EV-98-0170, Rev. 1. Utilizing these SFRs, EEQ Engineering developed the Environmental Qualification Master List (EQML) for the EEQ Specification SP-EE-352, Rev. 4. The EQML includes about 577 end devices and commodities that require environmental qualification.

During the last year a walkdown was performed of all accessible equipment identified in the EQML. This year the licensee performed further walkdowns of additional equipment requiring design modifications. The results from both walkdowns were reconciled with design documents to ensure their EEQ status. The inspector performed a independent walkdown of several SOV circuits outside the containment building to ensure their circuit configurations as documented in their qualification records. Circuit modifications similar to the seven subject SOVs inside the containment building had been performed. No concerns were identified.

c. Conclusions

After reviewing the EEQ documents for the seven SOVs and performing in-plant walkdowns, the NRC concluded that the corrective actions taken by the licensee were acceptable. Hence, EEI 50-336/96-06-12, Violation 50-336/02082 and Unit 2 Significant Items List No. 19.5 are **closed**.

E8.5 (Closed) EEI 50-336/96-08-11 & Violation 50-336/03062: Hydrogen Monitors Rendered Inoperable due to Insufficient Air Flow; **(Closed - Unit 2 Significant Items List No. 23.1)**

a. Inspection Scope (92903)

The inspector reviewed the licensee's corrective action to address Escalated Enforcement Item (EEI) 50-336/96-08-11 and Violation 50-336/03062.

b. Observations and Findings

EEI 50-336/96-08-11 and Violation 50-336/03062 concerned the fact that the hydrogen monitors would not perform their design function due to insufficient air flow past the thermal conductivity cell when the containment pressure is low. This failed to satisfy Technical Specification (TS) 3.6.4.1 that required two operable independent hydrogen monitors. Also, Final Safety Analysis Report, Section 6.6.2.1, requires two independent hydrogen monitors outside the containment for periodic or continuous hydrogen concentration analysis and to ascertain that uniform mixing of the containment atmosphere is provided by the post-accident recirculation system.

As a corrective action, the licensee prepared Design Change Record (DCR) M2-96051 which replaced the containment hydrogen monitoring system with two new trains of equipment which were constructed to specific licensee specifications. The inspector reviewed the vendor manual and verified that the system was constructed to the licensee specifications. The inspector found that the specifications to which the system was designed provided for the design changes necessary to meet the licensing and design bases.

The inspector, together with the responsible licensee design and system engineers, walked-down the hydrogen monitoring system. The licensee engineers discussed the operation of the hydrogen monitoring system and each of its component parts. The licensee design engineer was knowledgeable in the design, installation, operation, and testing of the system. The appearance of the modified system showed good installation workmanship.

The inspector reviewed a Seismic Qualification Review (SQR) for components of the hydrogen monitoring system that indicated acceptability of the seismic mounting of the system components. During the system walk-down, supports were judiciously placed on the system piping to withstand the effects of a seismic event.

The inspector reviewed the hydrogen monitoring system modification post-modification test plan and the completed verification signatures for each element of the program. In review of the program and through discussion with the responsible engineer, the inspector found the test program to be comprehensive, covering each component individually, and as acting in the system. The testing included leak tests, electrical tests, and component performance tests. These supplemented the testing conducted by the component manufacturers.

c. Conclusions

The licensee's corrective actions taken to address EEI 50-336/96-08-11, Violation 50-336/03062, and Unit 2 Significant Items List No. 23.1 were found acceptable and therefore, these items are **closed**.

E8.6 (Closed) EEI 50-336/96-08-12 & VIO 50-336/01062: Failure to Establish Adequate Design Controls for the Steam Generator Replacement Modification; **(Closed) Unit 2 Significant Items List No. 23.2**

a. Inspection Scope (92903)

The inspector reviewed the licensee's corrective action to address Escalated Enforcement Item (EEI) 50-336/96-08-12 and Violation 50-336/01062.

b. Observations and Findings

EEI 50-336/96-08-12 and Violation 50-336/01062 concerned the fact that due to an inadequate review of the steam generator replacement modification, the licensee failed to identify that the design basis and the licensing basis regarding the time necessary to place the hydrogen monitors in service, and the time needed to take a containment atmosphere sample, could not be met during the 24 hours following a Loss of Coolant Accident (LOCA) when containment pressure was above 10 psig.

As corrective actions, the licensee prepared Technical Evaluation M2-EV-98-0202, Rev. 0, "Hydrogen Monitoring/Purge Systems Licensing and Design Bases Review", which re-computed the post-LOCA pressure/temperature profiles and reflected these in the safety functional requirements of the final safety analysis report (FSAR). The hydrogen monitoring system and containment radiation monitors were then modified utilizing the revised pressure/temperature profiles. The current licensing basis requires the hydrogen monitoring system to be operable within 70 minutes, based on a 40 minute operator action time and a 30 minute equipment warm-up time. The system is no longer restricted to 10 psig because new isolation valves for the radiation monitors were installed. These changes allow the hydrogen monitors to function within the licensing/design basis.

c. Conclusions

The licensee's corrective actions taken to address EEI 50-336/96-08-12, Violation 50-336/01062, and Unit 2 Significant Items List No. 23.2 were found acceptable and therefore, these items are **closed**.

E8.7 (Closed) EEI 50-336/96-08-13 & VIO 50-336/01252: Failure to Update the Unit 2 FSAR Regarding the Hydrogen Monitoring System: **(Closed - Unit 2 Significant Items List Nos. 23.3 and 9.2)**

a. Inspection Scope (92903)

The inspector reviewed the licensee's corrective action to address Escalated Enforcement Item (EEI) 50-336/96-08-13 and Violation 50-336/01252.

b. Observations and Findings

EEI 50-336/96-08-13 and Violation 50-336/01252 concerned the failure of the licensee to update the Unit 2 Final Safety Analysis Report (FSAR), Section 6.6.3.1, which stated that the hydrogen monitoring system is manually initiated within 12 hours following the accident, to reflect the licensing basis time of approximately 3 hours described in the licensee's letter to the NRC dated March 27, 1984, regarding NUREG 0737, "TMI Action Plan Requirements."

The inspector found that the replacement hydrogen monitoring system design will change the system activation time to 1 hour and 10 minutes. Documentation of the change to be included in the FSAR concurrent with those of plant design changes was reviewed by the inspector and found acceptable.

c. Conclusions

The licensee's corrective actions taken to address EEI 50-336/96-08-13, Violation 50-336/01252, and Unit 2 Significant Items List Nos. 23.3 and 9.2 were found acceptable and therefore, these items are **closed**.

E8.8 (Closed) LER 50-336/96-032-00 & 01: Potential Failure of Reactor Coolant System (RCS) Vent to Perform its Design Function

a. Inspection Scope (92903)

This inspector performed an on-site inspection of the licensee's actions taken to address licensee event report (LER) 50-336/96-032-00 & 01. This LER described several conditions that could prevent the RCS vent system from performing its function. The evaluation included a review of the licensee's documents to close of the issue, additional applicable documentation, as needed, and interviews of responsible engineering and supervisory personnel.

b. Observations and Findings

On October 8, 1996, the licensee identified several conditions that could prevent the RCS vent system from performing its design function. These conditions included the potential for water hammer in the RCS vent piping which could cause damage to the pipe supports resulting in exceeding piping allowable stresses. The potential for the water hammer event was caused by an inadequate design of the reactor head vent portion of the RCS vent system. Installation of the RCS vent system did not account for the incorrect slope of the pre-existing reactor head vent piping. Because of physical limitations, the licensee was unable to change the slope of the piping, therefore, the licensee re-analyzed the RCS vent piping.

The RCS vent system is used to vent noncondensable gases from the RCS during post accident conditions. The system was installed to comply with NUREG-0737, "Clarification of TMI Action Plan Requirements," Item II.B.1, "Reactor Coolant System Vents."

As a corrective action prescribed in LER 50-336/96-032-00 & 01, the licensee re-analyzed the RCS vent system. The inspector reviewed calculation 17236.00-NP(B)-001-FD, which evaluated the water hammer loads for the RCS vent piping. These loads were in the form of force-time histories and were applied to a computer model that represents the RCS vent piping from the reactor head to a discharge sparger located inside the containment at the intake of the containment air recirculation fans, (Ref. Calculation No. 79-228-189GM, Revision 5). The inspector noted that this piping analysis satisfied the allowable limits of the code of record which is ANSI B31.1, 1967 Edition.

In terms of the RCS vent system pipe supports, the licensee, in calculation 79-228-072GD, Revision 4, evaluated these supports in accordance with the requirements established in ANSI B31.1. As a result of these pipe stress and pipe support analyses, new supports and modifications to new supports were identified in modification package MMOD M2-97516. The inspector reviewed the input loads and support design for several supports added to the system, and found the new supports acceptable.

c. Conclusion

The licensee's corrective actions were adequate to address the licensee-identified concern regarding the potential for water hammer in the RCS vent piping. For this issue, no violation of NRC requirements was identified and LER 50-336/96-032-00 & 01 is **closed**.

E8.9 **(Closed) EEI 50-336/96-201-20, VIO 50-336/02042, & LER 50-336/96-018-01: Degraded Environmental Enclosures for Motor Control Centers B51 & B61 (Closed - Unit 2 Significant Items List No. 19.3)**

a. Inspection Scope (92903)

The inspector performed an on-site review of corrective actions taken to address the concerns discussed in Licensee Event Report (LER) 50-336/96-018-01, Escalated Enforcement Item (EEI) 50-336/96-201-20, and Violation 50-336/02042.

b. Observation and Findings

In March 1996, the licensee identified that there were inadequate door seals for the environmental enclosures for safety-related motor control centers (MCCs) B51 and B61 and reported the deficiency in LER 50-336/96-018. The LER described that a piece of the lower enclosure door seal for the MCC B51 was missing and the door latches for MCC B51 and B61 did not ensure a tight closure on the door seals. Up to one-half inch gaps were noted in the door seal areas. These seals are required for the enclosures to protect the MCCs from steam or humid air environment due to a postulated high energy line break (HELB) in the area. Following a steam line break in the auxiliary building heating system on the 14' 6" elevation, these enclosures will be exposed to a steam environment with a peak pressure of approximately 0.6 psig and a peak temperature of approximately 148 of. The area can also be impacted by a main steam line break (MSLB) in the auxiliary building. These MCCs are critical for the operation of the high pressure safety injection (HPSI), low pressure safety injection (LPSI), and charging systems. With condensation from steam or humid air forming on the surfaces of the MCCs, electrical shorts may occur. In addition, in the event of a HELB the temperatures in the MCC enclosures could rise well above the qualification temperatures of the MCC equipment (i.e., 131 of for 96 hours). The failure to promptly resolve deficiencies in the analysis and design of the MCC enclosures and the failure to identify and correct inadequate barrier seals were later determined by the NRC to be a violation (EEI 50-336/96-201-20 and Violation 50-336/02042).

In response to NRC IE Bulletin 79-01, "Environmental Qualification of Class IE Equipment," the licensee installed these electrical enclosures in 1981 and provided these enclosures with a non-QA cooling system. LER 50-336/96-018-01 stated that due to weaknesses in the programs to inspect and verify the integrity of environmental protective barriers, the degradation of the door seals was not detected and corrected. As corrective actions, the licensee replaced the MCC enclosure doors (DCN No. DM2-00-1365-96; MMOD No. M2-96571), installed safety-related A/C units (DCN No. DM2-00-0941-98), and developed inspection and maintenance procedures to ensure that environmental and HELB barriers are maintained operable at all times (SP-M2-CE-1007).

In addition to HELB requirements, the B61 MCC enclosure door is also categorized as a fire door. Therefore, both replacement MCC enclosure doors are steel with a mineral core and are qualified as QA Category 1, Class A, 3 hour-rated fire doors. The seismically qualified doors are load rated for HELB conditions and are qualified for a harsh environment. The inspector performed a walkdown of both the MCC enclosures and found the door seals to be in good condition with no gaps.

The licensee replaced the existing non-safety A/C units with safety related 24,000 Btu/hr A/C units in each MCC enclosure. The units were qualified for both harsh environment and seismic conditions, and each has a qualified life of 14.7 years. The new A/C units have adequate cooling capacity to maintain the maximum ambient temperature inside the vital MCC enclosures at 122 of or less during both normal plant operation and accident conditions.

Specification SP-M2-CE-1007, Rev.0 addresses the requirements for surveillance, inspection, repair and maintenance of Millstone Unit 2 HELB barriers. The Millstone Hazards Program Manual delineates the requirements for the inspection of HELB barriers. In response to those requirements, procedure U2 EN7 was generated. This procedure credits existing programs and procedures as appropriate and contains the details of the inspection process. Procedure U2 EN8 provides the instructions necessary for maintenance and repair of Unit 2 HELB barriers. The inspector reviewed these procedures and found them satisfactory.

c. Conclusions

Licensee design and procedural changes demonstrated that the B51 and B61 MCC enclosures will be able to perform their intended functions in the event of a HELB accident in the auxiliary building. The inspector concluded that the corrective actions taken by the licensee are appropriate. Hence, LER 50-336/96-018-01, EEI 50-336/96-201-20, Violation 50-336/02042 and Unit 2 Significant Items List No. 19.3 are **closed**.

E8.10 (Closed) EEI 50-336/96-201-28 & VIO 50-336/02092: Failure to Address the Station Blackout Issues Identified in the Vectra Assessment **(Closed - Unit 2 Significant Items List No. 31)**

a. Inspection Scope (37550)

The inspector reviewed the licensee's actions to address Escalated Enforcement Item (EEI) 50-336/96-201-28, Violation 50-336/02092, and Significant Items List (SIL) item number 31. These items pertain to the licensee's failure to address the Station Blackout (SBO) program deficiencies identified by Vectra in Assessment Report No.24-00116, Revision 0, dated October 1994. The review involved a variety of licensee documents, including applicable portions of procedures, analyses, calculations, drawings, and Adverse Condition Reports. The inspector also conducted interviews with the engineering staff and performed equipment inspections.

b. Observations and Findings

In 1934, Vectra was tasked by the licensee with reviewing the implementation of the SBO requirements delineated in 10 CFR 50.63. For Unit 2, Vectra identified 14 issues, including potentially inadequate SBO loading, voltage drop, and battery sizing calculations. The Vectra report also identified three items that were common to the three Millstone Units, i.e., loss of heat tracing, emergency lighting, and communications. For each finding the report included recommended corrective actions.

The NRC originally reviewed the resolution status of the Vectra recommendations for Unit 2 in May 1996 (Inspection Report 50-336/96-201). The NRC found that only one item had been addressed. The remaining items had been incorrectly identified as complete, even though the issues were still open.

During the current inspection, the inspector reviewed the actions taken by the licensee to address Vectra's findings. The inspector determined that the licensee had reviewed each finding and associated recommendations, and had taken action to address each finding. At the time of the inspection, all the actions the licensee had determined were required to resolve the issues had been completed. Several additional issues identified by the licensee during the resolution of Vectra's findings had been evaluated and the corrective actions scheduled. Except as described below, the inspector found the licensee's resolution of the identified deficiencies was acceptable and satisfied the NRC SBO requirements. The prepared analyses were reasonable; the calculations were detailed, conservative, and in accordance with industry standards.

Calculations No. 97ENG-01774-E2 and 97ENG-01774-E2, both Revision 1, were prepared to verify the adequacy of batteries 201A and 201B, respectively. The calculations addressed battery and battery charger capacity, available short circuit currents, and the adequacy of voltage at dc components. Section 3.3.2 of both calculations specified that "the minimum acceptable battery voltage is 105 VDc." This acceptance criterion is consistent with industry practices and the minimum acceptable battery and cell voltages specified in UFSAR Sections 8.5.2.2 and 8.5.3.1, respectively. This value, however, is acceptable only if it can be demonstrated that, with the minimum specified voltage at the battery terminals, the voltage available at the dc components is sufficient for the components to perform their safety functions. In reviewing the calculated voltages at selected components, the inspector identified the following two areas of concern:

<u>Inverter Input Voltage</u>

Inverters are typically supplied by vendors with a minimum input voltage setpoint of 105 Vdc. Below this voltage, the inverters shut-down to prevent potential misoperation. The Millstone Unit 2 inverter supplier similarly specified a minimum input voltage of 105 Vdc. Because in their calculations the licensee had assumed 105 Vdc at the battery terminals, they recognized that an inverter input voltage shut-down setpoint of 105 Vdc was not acceptable. Therefore, the licensee contacted the vendor who, in a facsimile dated September 18, 1997, stated that the inverters "will perform their intended function with an input of 103VDc." The vendor's statement implied that the inverter input voltage shut-down setpoint was lower than the value stated in the equipment specifications. Based on the vendor's facsimile, the licensee lowered the equipment specifications from

105 to 103 Vdc and, in the dc calculations, specified a minimum inverter input voltage of 104 Vdc.

Despite the vendors correspondence, the inspector expressed a concern that: (1) the licensee had revised the inverter specifications without verifying the inverters shutdown setpoint, and (2) the setpoint had never been verified. Although factory preset, setpoints have an operating band and are subject to drift. The licensee engineering staff should have recognized the possibility that the Unit 2 inverters shut-down setpoint might be different than the value stated by the vendor since, in 1994, the Unit 3 inverters were found to have shut-down setpoints of 104 Vdc, four volts higher than the 100 Vdc specified by the vendor (Inspection Report 50-423/93-81).

Control Cable Voltage Drop

In determining the minimum voltage available at safety-related components, the licensee first calculated the voltage drop from the battery terminals to several nodes, e.g., distribution and control panels, motor control centers, and switchgear. Then, the licensee used these nodes to calculated the minimum voltage of specific components. The inspector found this methodology acceptable and conservative. However, the inspector also found that an assumption used to calculate the voltage at primarily control components located within the cabinet or panel represented by the node was not always correct. Specifically, for components within a panel, the licensee assumed that the voltage on the component would be one volt less than that of the node. This was a reasonable assumption for wiring that remained entirely within the panel. However, the licensee used the same assumption when a control cable, originating in the panel, traveled to several different places in the plant before returning to the component within the panel. For such conditions the licensee should have also evaluated the voltage drop in the cable outside the node.

An example was device 62, an Agastat timer in Unit A302 of the 4160 Vac switchgear (Drawing No. 25203-32002, Sheet 1, Revision 7). The control cable of this device originates in Unit A302 and travels to two control room panels and another switchgear unit before returning to Unit A302 where the timer is located. For this timer the licensee had established a minimum required voltage of 97 Vdc (based on 96 Vdc design voltage and 1 Vdc voltage drop) and a minimum available voltage of 95.18 Vdc. In this case, because the available voltage was less than the required voltage, the licensee performed an evaluation to justify the difference. However, a review by the inspector of the control cable path showed that it was the same as that of the A302 circuit breaker closing coil for which the licensee had calculated a voltage drop of 11.12 Vdc. Therefore, the required voltage for the 62 timer should have been 107.12 Vdc (96 + 11.12 Vdc), indicating the earlier justification was not acceptable.

Evaluation of Findings

Regarding the inverters, despite the vendor correspondence, the licensee had no basis for lowering the voltage shutdown setpoint. Therefore, there was no assurance that with the minimum specified voltage at the battery terminals (105 Vdc) the inverter would not have shutdown. However, service tests performed in January 1999 and November 1998 on batteries A and B, respectively, indicated that the available terminal voltage at the end of the 8-hour cycle was approximately 117 Vdc for both batteries. Based on the current performance status of the batteries, a 12 Vdc margin existed for the inverter input voltage. Therefore, the inspector determined that this issue did not appear to be an immediate safety concern.

Regarding the licensee's failure to address voltage drop in control cables outside the component panels, although the issue potentially affected many components, the inspector believed it did not involve an immediate safety concern because (1) control components normally draw small amount of current and, hence, the voltage drop, even in long cable runs, is limited; (2) the current end-of-cycle voltage of both batteries is well above the design minimum of 105 Vdc; and (3) the conservative assumptions used in the calculation would further limit the voltage drop.

In the case of the 62 device described above, the inspector noted that the timer is energized at the same time as the closing coil. At that time, the calculated minimum voltage at the node is 105.93 Vdc. When the 11.12 Vdc voltage drop is considered, the minimum voltage at the timer is 94.81 Vdc and, therefore, within the range initially justified by the licensee.

The inspector discussed these findings with the responsible engineer and other supervisory personnel. In particular, the inspector discussed the need for evaluating, individually or generically, the minimum voltage of all safety-related components. The licensee understood the observations and initiated two Condition Reports (M2-99-1024 and M2-99-1417) to address them.

c. Conclusions

The licensee acceptably addressed the Station Blackout issues identified in the Vectra assessment. Therefore, EEI 50-336/96-201-28, Violation 50-336/02092, and Unit 2 SIL item number 31 are both closed. The prepared analyses were reasonable; the calculations detailed, conservative, and in accordance with industry standards. However, the inspector found that dc voltage drop calculations were inadequate in that two incorrect assumptions were identified in shutdown voltage of the safety-related inverters and voltage drop in control cables. This is a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." This concern had limited safety impact because the battery currently has sufficient spare capacity to compensate for the potential deficiency. The licensee initiated action to evaluate the issues. Therefore, this Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-05-03)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into their corrective action program.

E8.11 <u>(Closed) LER 50-336/97-006-00: Main Steam Line Break Inside Containment Could Result in Exceeding Design Pressure of Primary Containment During Certain Scenarios;</u> **<u>(Closed - Unit 2 Significant Items List No. 44)</u>**

a. <u>Inspection Scope (92903)</u>

The inspector performed an on-site review of the licensee's corrective actions to address Licensee Event Report (LER) 50-336/97-006-00. The evaluation included a review of the licensee's documents to showing closure of the issue, additional applicable documentation, as needed, and interviews of responsible engineering and supervisory personnel.

b. <u>Observations and Findings</u>

On February 11, 1997, the licensee identified that a main steam line break (MSLB) inside containment could result in the primary containment pressure exceeding its design value of 54 psig under the following conditions:

1) With the plant at the hot, zero-power condition, both auxiliary feedwater (AFW) pumps in operation, and the AFW discharge regulating valves open sufficiently to allow full flow, AFW flow to the faulted steam generator (i.e., the steam generator nearest the main steam line break) would go to its maximum value from the start of a MSLB accident (no single failure is involved in this scenario).

2) With the plant at the hot, zero-power condition, one AFW pump in operation, and the AFW discharge regulating valves throttled, a single failure of a time delay relay could cause AFW flow to the faulted steam generator to reach its maximum value at some time prior to the previously analyzed 180 seconds after the start of a MSLB accident.

Because the faulted steam generator would rapidly depressurize at the start of a MSLB accident and because system flow resistance would be low in the conditions described above, the AFW flow to the faulted steam generator rapidly increases to pump runout conditions. The additional water delivered to the faulted steam generator early in the event compared to the assumptions of the previous analysis results in an increase in the calculated peak containment pressure. The licensee initially reported this issue in LER 50-336/97-006-00, which was submitted on March 13, 1997.

In LER 50-336/97-006-00, the licensee committed to implement corrective actions to ensure that the plant response to a MSLB accident will not result in exceeding the design pressure of the primary containment. The principal corrective actions associated with this issue involve limiting the maximum AFW flow to a faulted steam generator by installing cavitating venturis in the AFW lines to each steam generator and reducing the maximum allowed initial containment pressure. The cavitating venturis provide minimal flow resistance at normal design AFW flow, but they provide very high resistance at flow rates above design values, which limits the maximum AFW flow to a faulted steam generator and precludes AFW pump runout. The corrective actions for several other issues identified through the licensee's configuration management program also affected assumptions used in the analysis of the MSLB accident. The licensee revised the analysis of the MSLB accident to reflect the limited AFW flow, the potential for AFW flow from the start of a MSLB accident, the reduced maximum initial containment pressure, and other changes related to the MSLB analysis.

The inspector reviewed the licensee's principal corrective actions. The inspector found that the implementation of the design change process and the installation activities associated with the cavitating venturis were adequate. The licensee requested and received a license amendment reducing the maximum initial containment pressure to 1.0 psig.

The inspector also reviewed the revised analysis of containment pressure response to an MSLB accident. The revised analysis reflected the installation of the cavitating venturis to limit AFW flow and the reduction in initial containment pressure. For low power cases, the analysis assumed that the AFW system was in operation at the start of the MSLB accident. The analysis results indicated that a MSLB accident initiated from the following conditions results in the limiting containment pressure:

1) The plant is at hot, zero-power conditions.

2) Both motor-driven AFW pumps are feeding the steam generators.

3) One vital AC power distribution panel fails, which disables one train of containment spray and one train of containment recirculation coolers.

With the corrective actions implemented by the licensee, the calculated peak containment pressure for this limiting case was 53.68 psig which was below the containment design pressure of 54 psig. The licensee used reasonable assumptions and approved computer codes in the analysis. Therefore, the inspector found the analysis acceptable.

c. Conclusions

The FSAR Chapter 14 accident analysis for a MSLB event initiated from low power was inadequate in that it did not consider the effects of AFW flow at the start of the accident which created the potential for peak containment pressure to exceed containment design pressure. The failure to establish an adequate MSLB analysis is a violation of 10CFR50, Appendix B, Criterion III, Design Control. However, the licensee identified this inadequacy and took adequate corrective actions to ensure containment pressure would remain below containment design pressure following a MSLB event. Therefore, this non-repetitive, licensee-identified and corrected violation is being treated as a **Non-Cited Violation, (NCV 50-336/99-05-04)** consistent with Section VII.B.1 of the NRC Enforcement Policy. LER 50-336/97-006-00 and Unit 2 Significant Items List No. 44 are **closed**.

E8.12 (Closed) LER 50-336/97-015-00 & 01: Potential for Water Hammer, Two-Phase Flow, and Thermally Induced Overpressurization during Postulated Accident Conditions; **(Closed - Unit 2 Significant Items List No. 55.2)**

a. Inspection Scope (92903)

The inspector performed an on-site review of the licensee's corrective actions to address Licensee Event Report (LER) 50-336/97-015-00 & 01. The evaluation included a review of the licensee's documents to close the issue, additional applicable documentation, as needed, and interviews of responsible engineering and supervisory personnel.

b. Observations and Findings

During a review of the conditions described in NRC Generic Letter 96-06, the licensee determined that during postulated accident conditions, the containment air recirculation (CAR) coolers may not be able to perform their safety function and certain containment penetrations may be susceptible to thermally induced overpressurization. The licensee initially reported this issue in LER 50-336/97-015-00, which was submitted on April 15, 1997.

The licensee found that the CAR coolers had the potential to develop two-phase flow during a loss of coolant accident (LOCA) coincident with a loss of off-site power (LOOP). The LOOP would result in a loss of cooling water flow from the reactor building closed cooling water (RBCCW) system to the CAR coolers. Because of the high heat content of the post-accident containment atmosphere, the licensee calculated that the heat transfer that would occur during the coast-down of the CAR cooler fans would be sufficient to heat the stagnant water within the CAR coolers to saturated conditions and create steam voids within the piping. The restoration of power from the diesel generator and the start of the RBCCW pump would restore cooling water flow to the CAR coolers, which would then collapse the steam voids within the CAR cooler piping. The resulting water hammer could affect the integrity of the RBCCW piping within containment which would render the RBCCW system inoperable. In addition, since the RBCCW piping forms a portion of the containment isolation boundary, a piping failure could affect containment integrity.

The licensee determined that the cause of this condition was inadequate consideration of potential failure modes during initial design and design verification. The potential for water hammer and thermally induced overpressurization during postulated accident conditions had not been addressed by the initial design.

As a corrective action, the licensee performed analyses evaluating the effect of the potential water hammer on system piping. The engineered safety features system is designed and tested to ensure that the RBCCW pumps automatically start within 26 seconds after accident initiation. Consequently, the licensee evaluated the transient piping and support loads imposed by the water hammer associated with collapsing the voids formed during the 26 second period that the RBCCW pumps could be idle following a LOCA coincident with a LOOP. The licensee determined that, with the modification of four pipe supports and the addition of one other pipe support, stresses within all RBCCW piping and supports would remain within design basis limits under the transient loads imposed by the postulated water hammer. However, the licensee found that the water hammer postulated to occur following a manual start of an idle RBCCW pump less than 45 minutes after accident initiation was not bounded by this analysis. The licensee implemented procedure changes to preclude a manual start of an idle RBCCW pump when post-accident conditions exist that are not bounded by the analysis for an automatic pump start. The inspector found that the licensee's corrective actions were adequate to ensure that the integrity of the RBCCW system piping, and containment, would be maintained following a design basis accident.

The licensee also evaluated the potential for thermally induced overpressurization of isolated piping segments following a LOCA or main steam line break accident. All containment penetrations were screened to identify piping segments that could be water-filled with no relief path during normal operation, which, therefore, would have the potential for thermally induced overpressurization. Nine penetrations were found to have this potential. The licensee resolved the concerns regarding thermal overpressurization within these nine penetrations through a combination of detailed analyses, plant modifications, and procedure changes. Specifically, the licensee completed the following actions:

1) For two penetrations, the licensee changed the associated operating procedures to ensure that the piping segment is drained before startup.
2) For two other penetrations, the licensee determined that the pressure acting below the seat of air-operated globe valves would lift the valve disc and relieve excessive pressure before piping stress would exceed design limits.
3) For another two penetrations, the licensee determined that the temperature of the fluid at the time of isolation would preclude thermal overpressurization.
4) For one penetration, the licensee determined that the pipe stress would remain within design limits because the volume of the isolated piping within containment was small relative to the total volume of the isolated piping segment.
5) For one other penetration, the licensee changed the normal position of a valve within containment to allow relief through the check valve that serves as the inboard containment isolation valve.
6) For the final penetration, the licensee implemented a modification to insulate the piping segment to limit the post-accident temperature increase and implemented a procedure change to ensure that the water temperature at the time of isolation, in combination with the limited post-accident temperature increase, would preclude thermal overpressurization.

The inspector determined that the identified plant modifications and procedure changes had been completed and that the revised procedures were executed during the plant's initial heatup from cold shutdown conditions during the current outage. The inspector found that the licensee's corrective actions were adequate to ensure that the integrity of the containment penetrations would be maintained during postulated accident conditions.

c. Conclusions

The NRC concluded that the licensee effectively addressed the concerns identified in LER 50-336/97-015-00 & 01, which involved the potential for water hammer and thermally induced overpressurization of isolated piping segments during postulated accident conditions. Therefore, LER 50-336/97-015-00 & 01 and Unit 2 Significant Items List No. 55.2 are **closed**. The failure of the licensee to consider the potential failure modes of isolated piping segments during the initial system design is considered a violation of 10CFR50, Appendix B, Criterion III, Design Control. This non-repetitive, licensee-identified and corrected violation is being treated as a **Non-Cited Violation**, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-336/99-05-05)**

E8.13 (Closed) LER 50-336/97-019-00: Automatic Test Initiator Sends Repeated Trip Signals to the RSST Feeder Breaker Timing Circuit

a. Inspection Scope (37550)

The inspector performed an on-site review of the licensee's corrective actions to address the deficiencies described in Licensee Event Report (LER) 50-336/97-019-00. The inspection included interviews of responsible engineering personnel, evaluation of the licensee report in accordance with 10 CFR 50.73, as well as the review of applicable licensee evaluation and closure documents.

b. Observations and Findings

On November 20, 1996, while testing the Reserve Station Service Transformer (RSST) Level 2 Undervoltage (degraded voltage) circuitry in the Engineered Safeguards Actuation System (ESAS) cabinets, licensee technicians observed that a control relay that had correctly energized after eight seconds, unexpectedly de-energized while the undervoltage signal was still present. The technicians also observed that the relay would cycle on and off as long as the degraded voltage condition existed. The significance of this event is that, under degraded voltage conditions, the resetting of the relay could have delayed the shedding of the emergency bus loads and the subsequent sequential loading of the diesel generators by as many as ten seconds

Subsequent review by the licensee determined that the relay cycling was the result of an unexpected interaction between the timing circuit and the Automatic Test Insertion (ATI), a feature of the ESAS. Specifically, the licensee determined that if the ATI pulse, which is inserted every 27 seconds, occurred while the ten-second (maximum) timing circuit was operating, it would cause the circuit to reset and timing to restart. Because no physical connection existed between the ATI sub-system and the timing circuit, the licensee also concluded that the anomaly was due to electro-magnetic interference (EMI) induced on an input pin of the Level 2 timer.

To address the deficiency, the licensee evaluated several alternatives. As stated in Design Change Request M2-97050, to alleviate the ATI interference, the licensee modified the ESAS sequencer modules to add one component and replace seven others. The modifications were installed and tested with satisfactory results. The inspector reviewed several documents related to the licensee's evaluation, root cause analysis, and resolution of the issue. The inspector also discussed with responsible engineering and supervisory personnel the scope and effectiveness of the modified modules. The inspector concluded that the licensee had acceptably addressed the identified deficiencies and the issue addressed by the LER is closed.

EMI and radio frequency interference (RFI) have in the past affected the correct operation of the ESAS. In most cases, the ESAS problems were the results of a 1992 system upgrade that changed several modules to a new design that used a lower operating voltage. The new modules were also more susceptible to EMI and RFI. As a result, the licensee has spent considerable effort and resources to identify the problems and correct them.

As stated in 10 CFR50, Appendix B, Criterion III, the adequacy of a design must be verified through design reviews or a suitable testing program. A suitable test testing program, in 1992, would have identified the deficiency that was discovered in 1996 using a revised test procedure. Considering, however, that: (1) a degraded grid condition had to exist for the problem to arise; (2) the degraded grid condition did not necessarily also include a loss of coolant accident; (3) the ATI signal had to coincide with the activation period of the timing circuit; and (4) the restart of the timing circuit would have added a maximum of ten seconds to the actuation functions; the inspector believed the deficiency to have limited safety and risk significance. Based on the above, this licensee-identified and already corrected violation of the design review process is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy.

c. Conclusions

The licensee's corrective actions adequately addressed LER 50-336/97-19-00 regarding unexpected electro-magnetic interference (EMI) between the Automatic Test Initiation feature of the Engineered Safeguards Actuation System (ESAS) and the timing circuit for the shedding and sequencing of the emergency bus loads. The existence of the EMI signal which, under degraded voltage conditions, could have delayed the shedding and sequencing of the emergency loads on the electrical buses by as much as ten seconds, was the result of inadequate design reviews and/or testing during the 1992 upgrading of the ESAS. This Severity Level IV violation is being treated as a **Non-Cited Violation (NCV 50-336/99-05-06)**, consistent with Appendix C of the NRC Enforcement Policy, which permits closure of most Severity Level IV violations based on their having been entered into their corrective action program. Also, LER 50-336/97-019-00 is **closed**.

E8.14 (Closed) LER 50-336/97-029-00 & 01: Piping Stress Analysis Performed in Support of IE Bulletin 79-14

a. Inspection Scope (92903)

This inspector performed an on-site inspection of the licensee's actions addressing licensee event report (LER) 50-336/97-029-00 & 01. This LER documented an inappropriate application of Section III of the ASME Code in the calculation of the pipe support loads for a main steam line located outside the containment. The evaluation included a review of the licensee's documents to showing closure of the issue, additional applicable documentation, as needed, and interviews of responsible engineering and supervisory personnel

b. Observations and Findings

On August 26, 1997, during a licensee review of a design modification for a main steam line located outside the containment, it was noted that the present pipe stress and pipe supports did not consider all the loads as required by the code of record, ANSI B31.1, 1967 Edition. Specifically, when the licensee performed a pipe stress analysis of the main steam system (MSS) piping in support of the NRC IE Bulletin 79-14, "Seismic Analysis for As-Built Safety-Related Piping Systems," the analysis (Bechtel Stress Problem 13) did not consider pipe elongation resulting from a thermal load nor the relative anchor displacement of the pipe resulting from a postulated safe shutdown earthquake (SSE). The licensee determined that the cause of this condition was an inappropriate application of the requirement established in the ANSI B31.1 Code of record.

As part of the corrective actions prescribed in LER 50-336/97-029-00 & 01, the licensee re-analyzed the main steam lines to provide structural qualification from the reactor containment building (RCB) penetration to the turbine nozzles. The inspector reviewed the re-analysis of the main steam line outside the containment (Calculation No. M2PROB13-01752-C2, Revision 1), and noted that the results showed that the present as-built configuration of the MSS piping and associated supports met the requirements established in the code of record which is ANSI B31.1, 1967 Edition.

While performing a review of the extent of condition, the licensee noted that the same condition also applied to the stress analysis for the main feedwater (MFW) piping located outside the containment building. The licensee performed a re-analysis of the MFW lines outside the containment (Calculation PROBL025-02133-C2, Revision 1). The results of the re-analysis met the code of record for pipe stress, although five supports were modified and one was deleted to meet the requirements of the code of record which is ANSI B31.1, 1967 Edition.

In both cases, the inspector noted that the licensee performed a detailed piping analysis for the relative seismic displacements between pipe supports attached to different floors within a building, and between different buildings with different natural frequencies (e.g., Containment Structure, Auxiliary Building, and Turbine Building). As such, relative building displacements were included within the operating basis earthquake (OBE) and SSE evaluations.

Based on these reviews and verifications, the inspector concluded that the licensee's corrective actions to bring the MSS and the FWS lines outside the containment within design basis was adequate.

ANSI B31.1 Code, 1967 Edition, requires that the pipe supports be designed to withstand the concurrent effects of dead weight, thermal, and earthquake loads. The calculations of record for the MSS and MFW lines outside containment evaluated the pipe supports and relative seismic anchor movements for the load combination consisting of a dead weight, thermal, and OBE. However, for the SSE, the load combination used in the calculation failed to consider the effects of thermal expansion and relative seismic anchor movements (Ref. Bechtel Stress Problem 13, Revision 10), thereby, creating a condition in which the MSS and MFW systems were outside their design basis. Although the licensee took the proper corrective actions to bring the MSS and the MFW piping and associated supports within allowable values established by the code of record, the failure to maintain both systems within their respective design basis was a violation of 10 CFR 50, Appendix B, Criterion III, Design Control. However, this violation is identified as a Non-Cited violation in accordance with Section VII.B.1 of the NRC Enforcement Policy because the licensee identified the design deficiencies and took appropriate actions to correct the discrepancies.

c. Conclusion

The failure to maintain the main steam and the feedwater systems within their design basis by failing to include required loads in pipe stress and pipe support calculations was a violation of 10CFR50, Appendix B, Criterion III, Design Control. However, the licensee identified these design basis discrepancies, and took adequate corrective actions to bring these two systems within the allowable values established in the code of record. Therefore, this licensee identified and corrected violation is being treated as a **Non-Cited Violation**, consistent with Section VII.B.1 of the NRC Enforcement Policy. LER 50-336/97-029-00 & 01 is **closed**. **(NCV 50-336/99-05-07)**

E8.15 (Closed) LER 50-336/97-037-00 & 01: Service Water Piping Liner Material Lodges in Strainer for the Emergency Diesel Generator Heat Exchangers; **(Closed - Unit 2 Significant Items List No. 55.4)**

a. Inspection Scope (92903)

The inspector performed an on-site review of the licensee's corrective actions to address Licensee Event Report (LER) 50-336/97-037-00 & 01. The evaluation included a review of the licensee's documents to showing closure of the issue, additional applicable documentation, as needed, and interviews of responsible engineering and supervisory personnel.

b. Observations and Findings

On November 26, 1997, the licensee issued Condition Report M2-97-2749, documenting that a 6" x 12" piece of PCV (polyvinyl chloride) liner material was found in the east strainer basket of the "B" Emergency Diesel Generator (EDG) service water duplex strainer during the performance of the monthly strainer basket swap. The PVC liner is used throughout the service water system for corrosion protection of carbon steel piping from the sea water. On December 27, 1997, the licensee submitted LER 50-336/97-037-

00, "Service Water Piping Liner Material Peeled Off and Lodged in the Strainer for the Emergency Diesel Generator Heat Exchangers Causing Reduced Flow to the Heat Exchangers". On November4, 1998, the licensee submitted LER 50-336/97-037-01, providing the conclusions from the inspections and repairs conducted in response to this event. A root cause investigation of the service water pipe lining failure was completed for LER 50-336/97-037-01 on July 30, 1998.

The inspector reviewed the following documents: LER 50-336/97-037-00 & 01; Condition Report M2-97-2749; Root Cause Analysis, dated July 30, 1998; Safety Evaluation S2-EV-98-0060, dated June 11, 1998; "Assessment of the Millstone Unit 2 Service Water System Piping Linings," NME-WC-98-231, dated June 3, 1998; procedures regarding the application, inspection and testing of linings; program instructions; and the NRC letter to the licensee transmitting the Safety Evaluation and revising the Updated Final Safety Analysis Report regarding the use of liners and coatings in the service water system.

Based on a review of these documents, the inspector found that the liner/coating problems were properly described, reported, evaluated and that corrective actions to correct the deficiencies and prevent recurrence are adequate. All recommendations made in the 'Assessment' (NME-WC-98-231) were incorporated into the licensee's corrective action program and completed. Program modifications were made that provided the necessary guidance for preventive maintenance, surveillance and inspection of the service water system internal pipe and component coatings and liners to prevent or allow early detection of any future liner or coating problems.

c. <u>Conclusion</u>

The licensee's corrective actions were found to be acceptable in addressing LER 50-336/97-037-00 & 01. Procedures and programs are in place to prevent recurrence or allow early detection of any future liner or coating problems. No violation of NRC requirements occurred. Therefore, LER 50-336/97-037-00 & 01 and Unit 2 Significant Items List No. 55.4 are **closed**.

E8.16 <u>(Closed) LER 50-336/98-012-00 & 01: Non-conservative Assumptions in the Facility Loss of Normal Feedwater Analysis; **(Closed - Unit 2 Significant Items List No. 55.5)**</u>

a. <u>Inspection Scope (92903)</u>

The inspector performed an on-site review of the licensee's corrective actions to address Licensee Event Report (LER) 50-336/98-012-00 & 01. The inspection included interviews of responsible engineering personnel, evaluation of the licensee report in accordance with 10 CFR 50.73, as well as the review of the applicable licensee evaluation and closure documents.

b. Observations and Findings

On May 21, 1998, the licensee identified that the assumptions used in the original loss of normal feedwater (LONF) analysis were non-conservative with respect to the steam generator water inventory at the time of reactor trip on low steam generator water level. The licensee determined that the reduction in steam generator full-power water inventory that resulted from replacement of the steam generators in 1992 had been underestimated. Also, the original LONF analysis did not consider steam generator blowdown flow nor did it include margin for auxiliary feedwater (AFW) pump degradation and instrumentation uncertainties. The licensee initially reported this issue in LER 50-336/98-012-00, which was submitted on June 22, 1998.

The licensee reported this issue as a condition outside the design basis of the plant. The basis for Technical Specification 2.2.1, "Limiting Safety System Settings," regarding the "Steam Generator Water Level - Low" reactor trip stated that the trip setpoint provided sufficient steam generator water inventory at the time of the reactor trip to allow more than 10 minutes before AFW flow would be needed. The AFW system consists of two independent motor-driven pumps and one steam-driven AFW pump, which has twice the capacity of one motor-driven pump. The motor-driven pumps start automatically within 240 seconds of AFW system actuation on low-low steam generator level. All three pumps have controls that allow operators to remotely start the pumps from the control room. The licensee's initial evaluation of the LONF event determined that steam generator dryout would not be avoided assuming manual initiation of AFW flow 10 minutes after the reactor trip. However, the licensee determined that steam generator dryout would be avoided if the automatic initiation of AFW flow was credited in the analysis.

Subsequently, the contractor performing external oversight of the licensee's configuration management program identified an additional non-conservative assumption in the LONF analysis. The existing LONF analysis had been focused on scenarios that minimized delivery of AFW flow by assuming maximum steam generator pressure. This condition occurs when the steam generators release steam through the safety relief valves, which occurs when the main condenser steam dumps and the atmospheric steam dumps are not available. However, operation of the main condenser steam dumps was found to reduce the margin to steam generator dryout in certain scenarios by reducing steam generator inventory early in the transient. For certain AFW system configurations, this effect more than offsets the effect of higher AFW flow resulting from the lower steam generator pressure caused by steam dump operation. To address this concern, the licensee evaluated a revision to the steam generator low level trip setpoint to increase steam generator inventory at the start of the transient.

In LER 50-336/98-012-01, which was submitted on December 23, 1998, the licensee reported that a revised LONF analysis had been completed and that an evaluation of other analyses described in Chapter 14 of the Final Safety Analysis Report (FSAR) had been performed to ensure that appropriate values for steam generator water inventory were used. The revised LONF analysis determined that adequate margin to steam generator dryout would be provided by increasing the "Steam Generator Water Level -

Low" setpoint and crediting automatic initiation of AFW flow from the motor driven AFW pumps.

The inspector reviewed the revised analysis entitled "Millstone Unit 2 Loss of Normal Feedwater Flow Transient With Reduced Auxiliary Feedwater Flow," Revision 1, December 1998. This summary report describe the five analyzed cases involving an instantaneous loss of main feedwater from 102 percent power and assuming the maximum allowed positive reactivity feedback and the maximum permitted pressurizer level. Cases 1 and 2 verified acceptable AFW performance with offsite power available and the reactor coolant pumps running and the steam generator safety relief valves acting as the heat sink. Cases 3 and 4 verified acceptable AFW performance with a loss of offsite power coincident with the reactor trip and a natural circulation cooldown. Case 5 verified acceptable AFW performance with offsite power available and the main condenser steam dump system in operation. In Case 1, the assumed single active failure was the steam-driven AFW pump, but in Case 2, the assumed failure was one of the two motor-driven AFW pumps. Case 3 was similar to Case 1, and Case 4 was similar to Case 2, except for the assumption of the loss of offsite power. Case 5 repeated Case 2, but the steam dump system was enabled. For Cases 1-4, the previous Technical Specification steam generator water level - low reactor trip analytical limit of 34 percent was assumed, but, for Case 5, the revised limit of 43 percent was assumed. The inspector found the revised analysis acceptable.

The licensee submitted a proposed revision to Technical Specification 2.2.1, its bases, and Chapter 14 of the FSAR. The proposed change to the Technical Specifications requested that the "Steam Generator Water Level - Low " reactor trip setpoint be increased from 36.0% to 48.5% and the allowable value be increased from 35.2% to 47.5%. The revised LONF analysis provided the licensee's justification for the changes to Technical Specification 2.2.1 and the FSAR. The proposed changes were subsequently approved by the NRC. The inspector verified that setpoint and surveillance procedure changes had been implemented through the licensee's design control and procedure change processes, respectively.

c. <u>Conclusions</u>

The FSAR Chapter 14 accident analysis for a LONF event was found by the licensee to be inadequate in that inaccurate and non-conservative assumptions were used for the initial steam generator water level and other parameters and this is considered to be a violation of 10CFR50, Appendix B, Criterion III, Design Control. However, the licensee identified the discrepancies, and took adequate corrective actions which provided an adequate margin to steam generator dryout following a LONF event. Therefore, this non-repetitive, licensee-identified and corrected violation is being treated as a **Non-Cited Violation, (NCV 50-336/99-05-08)** consistent with Section VII.B.1 of the NRC Enforcement Policy. LER 50-336/98-012-00 & 01 and Unit 2 Significant Items List No. 55.5 are **closed**.

Report Details

Summary of Unit 3 Status

Unit 3 operated at approximately 100 percent power during the inspection period. On March 4, operators reduced power to approximately 45 % due to a storm with southerly winds. Winds from the south and southwest challenge the Unit 3 intake structure; due to its physical orientation, seaweed is carried into the intake under these conditions and has a potential to degrade the effectiveness of the condenser waterboxes. Operators therefore reduced power to backwash the waterboxes and maintain the unit online. Following the storm, operators returned the plant to 100 percent power on March 5.

U3.I Operations

U3 O1 Conduct of Operations

O1.1 General Comments/Operational Followup (71707, 92901)

The inspector conducted frequent reviews of ongoing plant operations, including observations of operator evolutions in the control room; walkdowns of the main control board; inspection-tours of plant areas housing safety systems in operation or standby conditions; and observations at several morning and shift turnover meetings. The inspector witnessed or conducted a subsequent review of the following operational activities. Specific attention was directed to compliance with the plant technical specifications (TS), response to plant challenges and changing conditions, and the interaction between the operators on shift and other plant personnel.

a. Operators conducted a rapid reactor downpower from full power to 45 percent on March 4, 1999 in response to a storm with high winds, challenging the Unit 3 intake structure with seaweed and debris. The operations staff, with support from several other departments, performed response activities in accordance with operating procedure, OP 3215 (Degraded Intake). The back-up Shift Manager assumed responsibilities for supervision and coordination of all recovery actions at the intake structure. Over the course of the storm, the inspector witnessed maintenance of the trash racks, traveling screens, and screen wash system, including filter swaps and repair to a screen wash equalizing line that had failed. The inspector noted the stationing of security officers to compensate for opening access to vital area barriers. During the storm, the technical staff routinely checked operating parameters on the equipment in service, both safety-related (e.g., service water) and non-safety (e.g., circulating water).

The inspector also observed control room operator and Unit 3 management response to this storm. Operators effectively used the rapid downpower procedure to reduce power to backwash the waterboxes and maintain the unit on line. The inspector noted management's conservative decision to reduce power to 45 percent, to prevent a transient on the secondary plant (e.g., turbine trip) from causing a reactor trip. Operations personnel maintained effective command and control of the evolution and focused on the safety of the reactor core, despite several nonsafety-related, screen house equipment challenges. After the weather and plant stabilized, operators properly restored the unit to 100 percent power the following day. Subsequently, the licensee appropriately reviewed the plant problems and equipment deficiencies that had surfaced during this transient and plant evolution, documenting the collective issues in a condition report, CR M3-99-0681, for follow-up corrective measure implementation.

b. On March 12, 1999, the control room Shift Manager notified the NRC headquarters duty officer, in accordance with 10 CFR 50.72, of the discovery that control room access door (C-49-1) latch mechanism had not been qualified/tested to withstand the design differential pressure conditions, resulting from a high energy line break (HELB) in the turbine building. This control room door was immediately closed to access, using an alternative "dogged" latching mechanism that had been installed earlier in the year in response to door latching problems that required plant entry into TS 3.0.3 limiting condition for operation. The inspector reviewed the operability determination, OD MP3-100-98, assessing the impact of the re-calculated HELB pressure on several doors, penetrations, and structural components, serving as barriers between the turbine building and safety-related equipment in the control building. The inspector also conducted a walkdown of the pathways between the turbine building and control building, particularly examining the doors and penetrations in the control room envelope.

Subsequent testing by the C-49-1 door vendor, with design criteria supplied by the licensee engineering staff, verified that this door was qualified to withstand HELB pressure, and the "dogged" latches were removed and normal access restored. However, based upon the number of entries/exits through this door, questions arose regarding the average amount of time the door was open; thus not being capable during these ingress/egress periods to perform its HELB function. Licensee response to this concern included tracking the reduced number of entries based upon relocation of the operation work control staff from the control room to a trailer, in preparation for the upcoming refueling outage (RFO6), as well as directing most control room traffic to the west access door, which is not subject to HELB design considerations. The inspector discussed these actions with plant management and also discussed with engineering personnel the planned corrective measures to address the door C-49-1 HELB concerns during RFO6.

c. The inspector reviewed the licensee's actions following the receipt of a momentary grid stability trouble alarm on March 24, 1999. The momentary alarm was generated from the Double Line Trip Detector and Failed Detector Unit Rejection Scheme (DBURS), which has protective relay schemes to detect faults on specific transmission lines, thereby preventing a multi-unit trip. Specifically, the system was designed to trip Units 1 and 3 if a loss of two specific transmission lines occurred. As a result, the licensee initiated condition report M3-99-0906 to track the issue to resolution, and to date, the specific cause for the momentary alarm condition has not been identified. Regarding DBURS, an engineering work request (EWR) had been submitted several months earlier to facilitate the permanent deactivation of the system, but approval and subsequent deactivation of the system has not yet occurred. However, the overall impact of this alarm is mitigated by the present condition of Unit 1, in that DBURS is not armed. The DBURS feature is designed to automatically arm when net combined output from

Millstone Station is greater than 2200 MWe (i.e., all three units would have to be on-line). Therefore, the inspector verified in this review that no DBURS system trip signal could be generated that would result in an unnecessary Unit 3 trip.

d. Also on March 24, 1999, with the unit at full power, the "B" train boric acid transfer pump was removed from service for the performance of corrective maintenance. The inspector reviewed TS 3.1.2.2 and determined that the required number of boron injection flow paths remained operable. This TS limiting condition for operation could be met with only two operable flow paths from the refueling water storage tank (RWST), a tank containing water with a maximum boron concentration of 2900 parts per million (ppm). However, since TS 3.1.1.1 specifies borated water solutions greater than or equal to 6600 ppm boron, an additional question was raised regarding shutdown margin requirements when the boric acid transfer functions are unavailable. The inspector reviewed the abnormal operating procedure, AOP 3566 for Immediate Boration and determined that procedural steps allow the use of borated water from the RWST to restore shutdown margin requirements by increasing charging flow to the equivalent boration rate. The inspector verified that these AOP provisions were technically consistent with TS 3.1.1.1 requirements.

The inspector also evaluated certain condition reports (CRs) and any associated operability determinations (ODs), for compliance with TS, procedural, and reportability criteria. The following CRs were reviewed, and the corrective actions assessed, for consistency with license requirements and regulatory guidance:

-- CR M3-99-0802, involving quench spray pump operability in accordance with TS 3.6.2.1

-- CR M3-99-0980, involving safety injection pump operability in accordance with TS 3.5.2

-- CR M3-99-1021, involving quench spray pump design requirements, and OD MP3-009-99, documenting full quench spray system operability

-- CR M3-99-1046, involving residual heat removal valve operability in accordance with TS 3/4.6.1.1, consistent with the Unit 3 Conduct of Operations procedure, OP 3260

Where necessary, the inspector discussed these CRs and their disposition with the cognizant operations, engineering, and licensing personnel. Appropriate TS entries were logged and adequate actions taken by the operators on shift. Conformance with the applicable design bases and reportability requirements were considered by the licensee staff. The inspector evaluated the licensee position relative to operability and reportability for the documented system discrepancies and identified no problem areas or concerns.

Overall, Unit 3 staff response to the operational challenges, operability concerns, and equipment problems that emerged during this inspection period was adequate; with evidence of conservative decision making by plant management, and appropriate actions and timely corrective measures taken by the operators on shift.

U3 O7 Quality Assurance In Operations

O7.1 Nuclear Oversight Activities (40500, 92901)

Over the course of this inspection period, the inspector conducted periodic discussions with Nuclear Oversight management personnel to assess the effectiveness of the audit and surveillance activities being conducted as part of the Nuclear Oversight Verification Plan (NOVP). The inspector reviewed the Nuclear Oversight Monthly Report, covering the period from March 12 to April 8, 1999, noting an emphasis on the preparedness of the unit staff for RFO6 work. Nuclear Oversight evaluations in the areas of operations, work control, and corrective action appeared focused appropriately on improvement efforts for configuration control, on-line scheduling and risk management, and the timely closure of condition reports.

The inspector also reviewed a sample of surveillance reports issued during this inspection period and the Nuclear Oversight Assessment Plan for RFO6. The Nuclear Oversight transition plan for the licensee management reorganization scheduled for completion after RFO6, along with specific milestones for completing key assignments, were discussed in a meeting with the Director of Nuclear Oversight. The NOVP results and assigned ratings were also assessed and discussed with licensee management.

During plant inspection-tours and observation of control room evolutions, the inspector observed and held discussions with Nuclear Oversight personnel in the performance of their quality assurance duties. During one unit walkdown, the inspector observed a review of the adequacy of posted field and equipment information by an oversight inspector. This not only resulted in the initiation of a condition report, but also was noted as an issue that line management emphasized for review during their daily tours of the unit. This specific example, in conjunction with the broader NOVP assessments and the other interactions observed between oversight inspectors and unit staff, appear to highlight the direct involvement and positive impact that Nuclear Oversight continues to exert upon Millstone Station performance. Such efforts and their results will receive further NRC attention as the licensee reorganization efforts continue and future oversight emphasis shifts to RFO6 work and subsequently back to power operation.

U3 O8 Miscellaneous Operations Issues

O8.1 (Closed) LERs 50-423/98-12-00 and 01: Potential Loss of Residual Heat Removal Pumps Due to Minimum Flow Protection (Closed) URI 50-423/98-206-05: Restart Items

a. Inspection Scope (92901)

The licensee identified an unanalyzed condition that could potentially result in a loss of minimum flow recirculation cooling to the residual heat removal (RHR) pumps under certain accident conditions. This could cause minimum flow through recirculating valves

(3 RHS FCV 610&611) potentially causing cycling following a small break loss of coolant accident (SBLOCA), provided the pressure in the RCS stabilized at or near the RHR pump shut off head, and there was sufficient separation between the minimum flow valve open and close control setpoints. The inspector reviewed design changes, root cause evaluations and design change testing to determine if the unanalyzed condition was addressed.

b. Observations and Findings

The inspector reviewed a quantitative analysis that provided the timing sequences to be installed in the time delay relays for the flow control valves to prevent cycling during testing and a SBLOCA condition. The inspector noted that thermel overloads for the motor operators (for the flow control valves) also needed adjustment to conform with the analysis. The inspector confirmed that the time delay relays and the motor operator overloads were set to the analysis setpoints. The inspector noted that training of engineering and operational management was conducted to 1) emphasize the importance of reviewing abnormal conditions that occur during testing, 2) document an engineering position that might impact equipment's safety function, and 3) review equipment abnormalities for overall system operation, even if it is concluded that the equipment is working as designed. A "Conduct of Engineering Procedure" was developed to define management's expectations for the trending of, and the analysis of, equipment performance, for the timely resolution of repetitive equipment operating deficiencies.

c. Conclusions

The unresolved condition was corrected and management expectations were put into effect to address recurrence of a similar issue. The inspector did not identify any violation associated with this item. **URI 98-206-05 and LERs 50-423/98-12-00 and 01 are closed**.

O8.2 (Closed) LERs 50-423/97-54-00 and 01: Westinghouse Fuel May Exceed 10 CFR 50.46 Maximum Cladding Oxidation Design Criteria

a. Inspection Scope (92901)

The licensee identified a Westinghouse analysis that determined the calculated pressures within certain fuel rods could exceed a fuel rod design criterion and the pellet-to-clad gap could re-open. This could result in exceeding the 17% maximum cladding oxidation limit following a loss of coolant accident (LOCA). The inspector reviewed the Westinghouse analysis and licensee actions to determine if the above condition was addressed.

b. Observations and Findings

The inspector reviewed the Westinghouse specific analysis for Millstone 3, current cycle, that showed none of the fuel assemblies had the combination of design features that made them susceptible to the gap re-opening scenario provided certain core flows and pH were maintained. The licensee modified operations so that proper core flows and pH were maintained to insure the limiting fuel assembly was in compliance with the 17% limit for maximum cladding oxidation. The inspector noted that the licensee issued the cycle 7 core reload plan (EWR M3-98009) that contained recommendations to provide a more defined configuration to eliminate or significantly reduce the possibility of operational concerns, including fuel corrosion issues, without a TS change or modification to the plant.

c. Conclusions

The fuel problem that could have resulted in a 17% maximum cladding oxidation limit has been satisfactorily addressed by the licensee. **LERs 50-423/97-54-00 and 01 are closed**.

O8.3 (Closed) LER 50-423/98-27-00: Unmonitored Flow Path for Injection Cooling Pumps May Prevent Detection of Pump Degradation

a. Inspection Scope (92901)

The licensee identified unmonitored flow paths (minimum flow recirculation lines) existed for the fuel oil transfer, control building chilled water, service water, and safety injection pump cooling pumps during in service testing (IST). This condition may have caused the potential for affecting the measured flow and differential pressure, thereby masking pump degradation. The inspector reviewed licensee documentation to determine if the IST concerns were corrected.

b. Observations and Findings

The inspector determined that the licensee reviewed past testing of the above delineated pumps which concluded that pump degradation beyond the ASME code acceptance had not occurred. The inspector reviewed revisions to the pump IST procedure noting that the acceptance criteria for the lower band of differential pressure had been changed from +/- 10% to +/-6% as recommended by the licensee's technical evaluation (M3-EV-98-0083). The change accounts for the remote possibility that there is no flow in the recirculation line making the results conservative. The inspector also confirmed that additional training of IST personnel was conducted that discussed the potential impact of unmonitored flow paths and the ability to detect degradation of the pumps with unmonitored flow paths.

c. Conclusions

The unmonitored flow paths testing of the above pumps did not cause degradation. New procedures are in place to alert the operator to the potential problems related to unmonitored flows. Therefore, **LER 50-423/98-27-00 is closed**.

O8.4 (Closed) LER 50-423/98-13-00: Technical Specification Required Sampling During Mode 5 Not Completed for Steam Generator (S/G) Drain Down

a. Inspection Scope (92901)

The licensee identified a sampling deviation from a TS requirement (24 hours) for the A, B and D steam generators (SGs) during drain down with the radioactive effluent monitoring instrumentation out of service. The inspector reviewed the root cause evaluation, procedure changes and a training module to determine if the cause of the incident was corrected.

b. Observations and Findings

The inspector verified the licensee determined the discharge limits were in specification prior to the discharge and right after the missed surveillance was identified. The SG blow down procedure (SP 3882) and the discharge form were changed to clarify their usage and applicability during the drain down of SGs in wet layup. The root cause analysis determined the reason for the problem was lack of communications between the operations staff and the operators. The inspector verified that enhancements were made and training was presented to the operations and chemistry staff regarding the draining of steam SGs.

c. Conclusions

Failure to perform the required sampling during Unit 3 steam generator drain down is a violation of TS 3.3.3.9. The licensee's corrective actions were timely and considered acceptable. Therefore, this licensee-identified and corrected violation is being treated as **a non-cited violation (NCV 50-423/99-05-09)**, consistent with Section VII.B.1 of the NRC Enforcement Policy. LER 50-423/98-13-00 is **closed.**

O8.5 (Closed) LER 50-423/98-19-00: IST Acceptance Criteria Do Not Assure That the Design Minimum Check Valve Flows are Obtained

a. Inspection Scope (92901)

The licensee identified that an evaluation (M3-EV-97220) performed to evaluate the minimum required accident mitigation flow rates, and the source of each flow rate requirement for check valves, were included in the scope of the IST program. The review showed that check valve ability to pass the required flow for the reactor plant reactor component cooling water, the control building chilled water, and the spent fuel pool cooling systems had not been documented. The inspector reviewed corrective actions taken by the licensee.

b. Observations and Findings

The inspector verified that the procedures for the IST testing, for the above systems, were revised to include the testing of the check valves. The inspector also verified that the testing was successfully completed for the check valves.

c. Conclusions

The licensee's corrective actions were timely and considered acceptable. **LER 50-423/98-19-00** is **closed**.

O8.6 (Closed) LER 50-423/98-20-00: Daily Check of Radiation Monitor not Performed in Accordance with Technical Specifications

a. Inspection Scope (92901)

The licensee identified that the daily channel check of the radioactive liquid effluent waste neutralization sump monitor and flow channel was not performed. The inspector reviewed licensee corrective actions to determine if they were acceptable.

b. Observations and Findings

The channel check was only to be performed during periods of release, however, the way the logs were set up, and the instructions that were provided, were misleading to the control room operator. This resulted in the space provided for the channel check being filled in as "no flow" rather than a channel check. The inspector verified that the log requiring the channel check has been changed to clarify who is responsible to perform and document the check. This change places the responsibility for performing the channel check, during the actual discharge, on the plant equipment operator.

c. Conclusions

The licensee's failure to perform a daily check of a Unit 3 radiation monitor is a violation of Technical Specification 4.3.3.9. The licensee's corrective actions were timely and considered acceptable. Therefore, this licensee-identified and corrected violation is being treated as a **non-cited violation (NCV 50-423/99-05-10)**, consistent with Section VII.B.1 of the NRC Enforcement Policy. **LER 50-423/98-20-00 is closed.**

O8.7 (Closed) LER 50-423/98-30-00: Historical Event: Channel Calibration of the Hydrogen Recombiners Does not Meet the Requirements of Technical Specifications

a. Inspection Scope (92901)

The licensee identified that the surveillance procedure to perform hydrogen recombiner channel calibration did not verify that; 1) the T-1 timer blocked the "reaction chamber gas temperature low" alarm circuit, and 2) that the "temperature monitoring controller" provided the power output to the recombiner heater based on in the control current input.

This violates a TS operability requirement for channel calibration of the recombiner instrumentation controls. The inspector reviewed the licensee's corrective actions to determine their effectiveness.

b. Observations and Findings

The inspector reviewed newly revised calibration procedures (SP 344L01 and L02) that were modified to correct the problems outlined above. The inspector confirmed that the recombiners were calibrated successfully using the new procedures.

c. Conclusions

The historical failure to perform a channel calibration of the Unit 3 hydrogen recombiners is a violation of technical specifications. The licensee's corrective actions were timely and considered acceptable. Therefore, this licensee-identified and corrected violation is being treated as a **non-cited violation (NCV 50-423/99-05-11)**, consistent with Section VII.B.1 of the NRC Enforcement Policy. **LER 50-423/98-30-00 is closed**.

O8.8 (Closed) LER 50-423/98-32-00: Missed Fuel Handling Crane Limit Switch Surveillance Test Performance

a. Inspection Scope (92901)

The licensee identified that the new fuel handling crane limit switches were not tested at least once per seven days as required by TS 4.9.7. The inspector reviewed licensee corrective actions to determined their effectiveness.

b. Observations and Findings

The inspector confirmed the limit switches were tested satisfactory during the seven day interval prior to the missed surveillance, and that they were tested satisfactory after the discovery of the missed surveillance. The problem was that the operations personnel had mistakenly credited the spent fuel crane surveillance with the new fuel crane surveillance when signing the completed document. The inspector reviewed a lessons learned document that was circulated to all operations personnel emphasizing the missed surveillance. The document also reiterated licensee management's expectations pertaining to individual responsibilities when signing completed surveillances.

c. Conclusions

The failure to perform the Unit 3 fuel handling crane limit switch surveillance is a violation of Technical Specification 4.9.7. The licensee's corrective actions were timely and acceptable. Therefore, this licensee-identified and corrected violation is being treated as **a non-cited violation (NCV 50-423/99-05-12)**, consistent with Section VII.B.1 of the NRC Enforcement Policy. **LER 50-423/98-32-00 is closed**.

O8.9 (Closed) LER 50-423/98-33-00: Manual Engineered Safeguards Feature (ESF) Actuation of Motor Driven Auxiliary Feedwater Pumps Due to a Trip of the Motor Driven Steam Generator Feedwater Pump

a. Inspection Scope (92901)

The licensee identified a manual engineered safety feature (ESF) actuation of both A and B train motor driven auxiliary feed water pumps in anticipation of their automatic start in order to maintain SG water level following a mechanical failure of the motor driven feed water pump (MDFP) impeller. The inspector reviewed licensee corrective actions to determine their effectiveness.

b. Observations and Findings

The inspector reviewed complete and definitive documents used to replace the MDFP impeller noting that careful attention was paid to retaining evidence as to the cause of the failure. This was the second impeller that had been damaged in the MDFP. The two impellers were sent to an independent laboratory and the pump manufacturer for analysis. The cause was determined to be high vibration caused by low pump flow (running the pump on recirculation during start up activities). The licensee has put restrictions on the use of the MDFP during start up and a minimum flow at which the pump may be run. The inspector noted that new impellers designed to run at lower flow conditions were ordered.

c. Conclusions

The licensee's corrective actions were timely and acceptable. **LER 50-423/98-33-00** is **closed**.

O8.10 (Closed) LER 50-423/98-34-00: Inadequate Evaluation and Retest of Replacement Group Rod Indicator Displays

a. Inspection Scope (92901)

The licensee identified a manual reactor trip in response to a malfunction of the control rod group demand position indication counters. The inspector reviewed a root cause analysis and licensee corrective actions to determine their effectiveness.

b. Observations and Findings

While performing procedure "Multiple Rod Drop Time Test," it was noted that the group step counter was not changing while inserting shutdown bank "C." New group step counters had been installed during an extended outage. However, the full scope of the retesting was not performed because a jumper, to allow testing of the new counters, was not installed due to a paperwork omission. The inspector verified that the jumper was subsequently installed and testing was performed on the counters. The inspector also verified that training was performed with the first line supervisors and planning personnel stressing the need to insure that when an automated work order is referenced for a test, the work in the new automated work order satisfies the retest requirement of the original work order.

c. Conclusions

The licensee's corrective actions were timely and acceptable. **LER 50-423/98-34-00** is **closed**.

U3.II Maintenance

U3 M1 Conduct of Maintenance

M1.1 Maintenance and Surveillance Observations

a. Inspection Scope (61726, 62707)

The inspector observed portions of selected surveillance and maintenance activities to verify proper calibration of test equipment, use of approved procedures, conformance with technical specification limiting conditions for operation, and correct system restoration following testing. Portions of various activities were also observed during routine plant tours.

b. Observations and Findings

During this inspection period, the inspector witnessed the conduct of selected parts of the following automated work order (AWO) maintenance activities and performance of sections of the following surveillance procedures (SPs):

- SP 31005A, Moderator Temperature Coefficient (MTC) and Power Coefficient Measurements, Power Exchange Method
- SP 3610A3, RHR System Vent and Valve Lineup Verification
- SP 3712AA, Main Steam Isolation Valve Partial Stroke Test
- AWOs M3-99-00837 & 00842, Emergency Diesel Generator ("A" Train) air-start compressor maintenance
- AWO M3-99-01752, Rigging, Inspection, and Cleaning of the Component Cooling Water ("C" Train) heat exchanger
- AWO M3-99-04832, Canvas Cleaning of the Main Generator commutator and brush assemblies

The tagging of equipment in the field and on the main control board was checked and certain valve configurations were confirmed for restoration to the post-maintenance/testing lineup. The inspector verified proper foreign material exclusion (FME) controls and compliance with both FME postings and radiological controls by workers in the field. Where applicable, the inspector also examined technical evaluations and other engineering documents supporting the authorized work activities, and reviewed some of the surveillance test results.

With regard to the conduct of SP 31005A, the inspector noted that data from one power swing (i.e., an approximate 2% decrease and subsequent increase in electric load) was not used in the surveillance calculations because of procedural constraints on the time allowed for achieving the power reduction. The inspector discussed this situation with the lead test engineer, confirming that the resultant data was not indicative of a test failure, but should not be used in support of the technical specification acceptance criteria. Notation of this data exclusion was appropriately documented on the MTC Surveillance Form.

The inspector also attended some plant operations review committee (PORC) meetings where the certain observed maintenance and surveillance activities were discussed, noting relevant questioning by PORC members on safety-related aspects of the planned work. In the follow-up of specific maintenance activities, the inspector questioned the applicability of 10 CFR 21 to the identified equipment problems. Discussions with the cognizant system engineers provided satisfactory evidence, including vendor documentation, that the generic concerns relative to the questioned component deficiencies had been adequately addressed.

In general, maintenance and surveillance activities were well controlled and performed by knowledgeable operators, maintenance personnel, instrumentation and control (I&C) technicians and engineering personnel. The pre-job briefings were appropriate and discussed expected conditions, contingency actions, three way communications, and the importance of self and peer checking.

The inspector verified personnel compliance with approved procedures, work orders, and technical specifications. In addition, selected prerequisites were confirmed to be completed before testing; and proper restoration was verified after maintenance and testing activities were completed.

c. <u>Conclusions</u>

Observed maintenance and surveillance activities were appropriately controlled and performed in accordance with approved procedures or work orders and technical specification requirements.

U3.III Engineering

U3 E1 Conduct of Engineering

E1.1 New Reactor Fuel Receipt

a. Inspection Scope (60705)

In preparation for the May refueling outage, the licensee received several shipments of new reactor fuel this period. The inspector observed the fuel receipt and inspection activities to confirm compliance with required procedures and proper fuel handling, inspection, and storage.

b. Observations and Findings

Reactor engineering personnel coordinated and performed the fuel receipt and inspection in accordance with engineering procedure EN 31026, New Fuel Assembly and Insert Receipt and Inspection. The inspector verified that proper controls were maintained over the activity and fuel was handled carefully by maintenance personnel.

The inspector discussed the ongoing activity with reactor engineering, maintenance, and health physics personnel. All were knowledgeable of their responsibilities and performed adequately. One exception was noted during a radiation survey of an empty shipping cask, as discussed in Section R1.5 of this report. The inspector observed reactor engineers' appropriate inspections of the fuel for debris and damage before and during removal from the shipping casks and while the fuel was loaded into the dry storage vault. Proper foreign material exclusion controls were also noted. Any nonconformances were discussed with the fuel vendor and documented in CRs, if applicable.

The inspector also attended a lessons-learned session which encompassed the fuel receipt and inspection activities observed. The session was attended by most organizations, and those not in attendance supplied their feedback previous to the meeting such that all could share information. Participants were critical and identified strengths, weaknesses, and areas for improvement.

c. Conclusions

Unit 3 new fuel receipt activities were well controlled and performed by knowledgeable reactor engineering, maintenance, and health physics personnel. Fuel inspections were thorough and nonconformances were appropriately dispositioned.

IV Plant Support
(Common to Units 1, 2, and 3)

R1 Radiological Protection and Chemistry Controls

R1.1 Evaluation of Radioactivity Measurement Results for Aquatic Environmental Sample Media

Background

In a recently published article, Trace Metals and Radionuclides Reveal Sediment Sources and Accumulation Rates in Jordan Cove, Connecticut (*Estuaries*, Vol. 22, No. 1, 1999), the author described the application of a sediment characterization technique based on the distribution of non-naturally occurring trace metals to measure sediment accumulation rates in Jordan Cove, an estuary adjacent to the Millstone nuclear power plant facility. Accordingly, the article described measurements of trace quantities of cobalt-60 and cesium-137 in various sediment samples taken from Jordan Cove, which were reported to be attributable to releases from the Millstone facility. While the purpose of the article was not directed toward the conduct of operations at Millstone, the account of trace quantities of radioactive materials in Jordan Cove was widely reported in the local media and was a source of public concern, particularly since fish and shellfish are routinely taken from the area for public consumption.

The detection of trace quantities of facility related radioactive materials in the environment is not unexpected since the licensee has been licensed and approved to release processed waste water, in conformance with stringent regulatory criteria. Notwithstanding, the licensee is required to conduct an extensive radiological environmental monitoring program, in accordance with the specifications of the NRC approved Radiological Effluent Monitoring and Offsite Dose Calculation Manual to provide reasonable assurance and confirmation that the conduct of licensed activities has not resulted in undue risk to public health and safety, or adversely impacted the environment.

a. Inspection Scope (84750-01)

The inspector reviewed the 1995, 1996, and 1997 Annual Radiological Environmental Operating Reports (AREOR) required by the Technical Specifications (TS). These annual reports provided a comprehensive summary of the results of various environmental measurements taken in support of the licensee's Radiological Environmental Monitoring Program (REMP). The inspector also reviewed the licensee's environmental monitoring results for 1998 relative to samples of clams, scallops, lobster, oysters, and mussels collected at various locations, including Jordan Cove, as stipulated in the Radiological Effluent Monitoring and Offsite Dose Calculation Manual (REMODCM). Aquatic environmental sampling types and locations, within 2 miles from the discharge point (as listed in Table 1 and illustrated in Figure 1 which are contained in an attachment to this inspection report) were particularly assessed since these represented the areas in closest proximity to the release point (sample location 40).

b. <u>Observations and Findings</u>

NRC reporting levels for water, airborne particulate or gases, fish, shellfish, milk, and vegetable samples are specified in the REMODCM. There are no reporting levels for sediment specified in the REMODCM. Notwithstanding, the reporting levels for Cs-137 in fish is 2 pCi/gram (wet) and in shellfish is 8 pCi/gram (wet). The reporting levels for Co-60 in fish is 10 pCi/gram (wet) and in shellfish is 50 pCi/gram (wet). The highest sediment values cited in the *Estuaries* article were equivalent to 0.329 pCi/gram (cesium-137) and 0.39 pCi/gram (cobalt-60).

The following results were evident from review of the licensee's analytical results.

(1) Only trace quantities of facility-related radioactivity (Co-60: 0.272 ± 0.05 pCi/gram (wet), Zn-65: 2.575 ± 0.276 pCi/gram (wet), and Ag-110m: 0.806 ± 0.067 pCi/gram (wet)) were measured in native oysters taken from the discharge quarry (Sample Location 40). Though only trace activity, these values represented the highest concentrations measured by the licensee. Notwithstanding, the location is not open to members of the public, and is not available for fishing or clamming.

(2) Facility-related Co-60 was detected in a bottom sediment sample collected at Niantic Shoals (Sample Location 31); however, the measured activity was so low that it was indistinguishable from background radiation (i.e., 0.07± 0.03 pCi/gram, dry).

(3) Detectable levels of Mn-54, Co-58, Co-60, and Ag-110m were reported in 1997 in various aquatic flora samples; however, the measured activity was so low that it was indistinguishable from background radiation (i.e., Co-60: 0.021± 0.006 pCi/gram wet, and Zn-65: 0.026±0.013 pCi/gram wet).

(4) There were no facility-related radionuclides detected in fish, mussels, seawater, and scallops samples taken from various locations, including Jordan Cove.

These analytical results of the radiological environmental monitoring program confirmed that the licensee was maintaining radiological releases in accordance with license conditions. The results demonstrated that the trace quantities of radioactivity released from the facility as a result of licensed activities, were well below NRC's reporting criteria specified in the REMODCM.

The EPA dose limit (40 CFR 190) for the general public is 25 millirem (mrem) whole body, 75 mrem thyroid, and 25 mrem to any organ in a year. The NRC 10 CFR 50, Appendix I, "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low As Reasonably Achievable" for liquid effluents are 3 mrem whole body and 10 mrem to any organ, per a reactor, annually. In comparison, the normal expected background radiation dose is 284 mrem, annually.

The maximum calculated annual projected dose to adult, teen, and child for consumption of both fish and shellfish (based on information supplied by the licensee in the 1997 Annual Radiological Environmental Operating Report) was less than 1 mrem in a year to whole body or any organ, a fraction of the regulatory limits. Independent assessment by NRC inspection personnel verified that the licensee's methodology for calculating doses to members of the public was valid and was performed in accordance with the specifications of the REMODCM.

Additionally, NRC inspection personnel performed independent calculation of projected doses to the public based conservative assumptions with respect to exposure pathway and measured concentrations. The results of these calculations confirmed that radiological exposure of the public was negligible with respect to pertinent regulatory specifications, guidelines, and limits.

c. Conclusion

The analytical results derived from the licensee's radiological monitoring program provided reasonable assurance that the licensee conducted licensed activities in a manner that did not cause undue risk to the health and safety of the public or adversely impact the environment.

R1.2 Implementation of the Radioactive Liquid and Gaseous Effluent Control Programs

a. Inspection Scope (84750-01)

The inspection consisted of (1) a plant tour; (2) review of liquid and gaseous effluent release permits; (3) review of the 1997 Annual Radioactive Effluent Report; and (4) review of the Offsite Dose Calculation Manual (ODCM).

b. Observations and Findings

Radioactive liquid and gaseous effluent release permits were complete, including projected doses to the public.

The 1997 Annual Radioactive Effluent Reports indicated that projected doses to the public were well below the Technical Specification (TS) limits. There were no anomalous measurements, omissions or adverse trends in these reports. The ODCM provided all necessary parameters, such as effluent radiation monitor setpoint calculation methodologies, and site-specific dilution factors to satisfy requirements. Millstone adopted other necessary parameters (dose factors) from Regulatory Guide 1.109.

c. Conclusions

Millstone Units 1&2 maintained effective radioactive liquid and gaseous effluent control programs in that: (1) the TS/ODCM requirements for reporting effluent releases and projected doses to the public were effectively implemented; and, (2) the ODCM contained sufficient specification, information, and instruction to acceptably implement and maintain the radioactive liquid and gaseous effluent control programs.

R1.3 Implementation of the Radiological Environmental Monitoring Program

a. Inspection Scope (84750-2)

The implementation of the REMP, relative to program oversight; sample collection methodology; material condition, operation, and calibration of automatic sampling equipment; Land Use Census; reporting requirements; and the corrective action program was evaluated for the period between January 1998 and April 1999.

b. Observations and Findings

The administrative and implementing procedures were reviewed for technical content and clarity. The procedures were of sufficient technical depth and clarity to perform the required responsibilities. The SAB (formerly RAB) procedures have not yet been revised to reflect the organization and title changes. However, a TS change request had been submitted to the Licensing Group and approximately 75 station procedures that reference RAB have been identified for revision.

Sampling continued to be conducted by the Production Operations Services Laboratory (POSL) using POSLs REMP procedures and schedule. POSLs performance demonstrated good sampling techniques; the technicians understood the procedures and the schedule. The automatic sampling equipment were operable, calibrated, and maintained. The procedures and the schedule reflected the requirements in the REMODCM. The land use census for 1997 and 1998 was performed as required. The annual Radiological Environmental Operating report provided a comprehensive summary of the results of the REMP implemented during 1997, including the results of the land use census and the interlaboratory comparison program, required by the REMODCM. The licensee met the TS reporting requirements for the annual report.

The REMP samples for the period January 1998 through April 1999 were collected from the required locations and from extra locations not required by the program. Overall, measurements of the REMP required samples identified no anomalous results. The licensee collected sediment from a special location 40A, in the quarry (discharge area) and identified trace amounts of Co-60 and Cs -137 at concentrations of 10.67 ± 0.28 pCi/g (dry) and 12.25 ± 0.38 pCi/g (dry), respectively. Also, trace amounts of Co-60 and Ag-110m at concentrations of 0.188 ± 0.014 pCi/g (wet) and 0.603 ± 0.082 pCi/g (wet), respectively, were identified in oysters sampled at location 40X, the discharge. The concentrations identified in the environment were below reporting levels required by the REMODCM. Dose projections based on the above concentrations were below the regulatory limits. The results will be published and discussed in the Annual Radiological Operating Report for 1998.

c. Conclusions

The radiological environmental monitoring program was effectively implemented in accordance with regulatory requirements. The licensee effectively performed sample collection activities, conducted the land use census, and maintained and calibrated the automatic sampling equipment and analysis equipment according to the appropriate procedures. The procedures were technically correct, but needed some administrative revision to reflect program oversight and implementation responsibilities.

R1.4 Implementation of the Meteorological Monitoring Program

a. Inspection Scope (84750-2)

The implementation of the Meteorological Monitoring Program, including maintenance and calibration of the monitoring instrumentation, channel and functional checks, and approximately 40 Correction Reports, was reviewed for the period between January 1998 and January 1999.

b. Observations and Findings

Daily and biweekly surveillances were performed as required by procedures. Quarterly calibrations were also performed as required by the I&C calibration procedure (C SP 400.2, *Meteorological Instruments Calibration*, Rev. 1) with the coordination of Instrument & Controls (I&C) and POSL. The calibration methodology was appropriate and the calibration results were within the acceptance criteria.

In response to findings and observations of the previous REMP and MMP inspection (Integrated Resident Inspection Report 98-207, Section R1.2 and R7.1 pertains) and a quality assurance audit (Nuclear Oversight Audits & Evaluation Audit report, 1998 pertains), the licensee established an owners group, Meteorological EDAN and Water Owners Group (MEWOG) in 1997. The owners group was established to (1) focus ownership of the Met responsibilities, (2) identify and track areas for improvement, and (3) correct identified meteorological instrumentation problems. Ownership of the meteorological instrumentation was established. The responsible group is Environmental Services - Nuclear (non-radiological). Environmental Services is the focal point where several groups coordinate calibration, maintenance and engineering support. Communication between the different responsible groups was improved. The owners group conducted a self-assessment to identify and address improvement opportunities. From this assessment, the licensee initiated over forty CR's during 1998 and 1999. Over thirty CR's were resolved and closed. For example, the licensee discovered a declining trend in the performance of the backup generator for the primary tower. The meteorological instruments calibration procedure was upgraded by I&C to reflect changes to the calibration methodology. The procedure was thorough and of the appropriate technical depth to perform calibrations according to the TS requirements. The licensee also established a Program Manual, effective 12/98; MP-28-MET-PRG identified the elements of the MMP and defined objectives and minimum requirements for implementing procedures and guidelines to ensure compliance to regulatory requirements. The CR's that remain open pertain to SODAR (out of service since April 1997) and the Mast (backup meteorological tower). Both SODAR and the Mast are described in the UFSAR. The licensee is planning to resolve these issues.

c. Conclusions

The meteorological monitoring program was effectively maintained and implemented in accordance with regulatory requirements. The licensee's performance with regard to maintaining the meteorological monitoring instrumentation reliable was also effective. The licensee improved meteorological monitoring instrumentation through program ownership and better communication, tracking areas for improvement, and correcting previous problems.

R1.5 Degraded Performance in Unit 3 Contamination Control

a. Inspection Scope (71750, 92904)

The inspector observed selected activities during routine plant tours and inspections to verify proper radiological work practices.

b. Observations and Findings

The inspector observed radiological work practices during the reactor fuel receipt and inspection activities, as described in Section U3 E1.1. As part of the release of the shipping casks after fuel was unloaded, radiological protection technicians cleaned out the inside of the casks with muslin then performed an alpha survey and a beta/gamma survey to verify no contamination. Most surveys were performed correctly. However the inspector noted that the incorrect side of the muslin was surveyed in one instance. When the RP technician observed this, he re-surveyed the sample for beta/gamma. He would not have re-surveyed the sample for alpha, however, without prompting by the inspector. This is a poor work practice, as the muslin would have provided enough shielding to alpha radiation such that surveying the incorrect side could have missed any actual contamination. The follow-up survey confirmed that no alpha contamination was present. The inspector verified that subsequent surveys were correctly performed.

During maintenance activities on a fuel handling tool inside a contaminated area, the inspector identified two other examples of poor contamination control. First, when a potentially contaminated tool was passed from the contaminated area to the clean area to be frisked, the RP technician in the clean area wore only cotton liners. Plastic surgical gloves were in the area, but were not worn in this instance. The inspector discussed the observation with the technician, who admitted the error. The tool was not released from the area for work in a radiologically clean area, however no personnel contamination resulted from this error.

Soon after the previous occurrence, a contractor individual went to steady the tool from a clean area by reaching into the contaminated area. Although the RP technician instructed the worker to wear gloves and a lab coat, the individual was observed wearing cotton liners and no plastic gloves. When the inspector brought this condition to the technician's attention, the worker was stopped, before performing the work, and reinstructed to wear the proper anti-contamination clothing.

The above items were discussed with the radiological protection manager and/or the responsible RP supervisor. CR 3-99-0960 was issued to document the condition. In the latter instance, the RP supervisor was aware of the occurrence and discussed it with the technician. The inspector observed proper radworker practices in each work area subsequent to the identified problems.

Although these instances are considered minor violations and did not lead to any personnel contamination o. improper release of contaminated material, these observations coupled with recent nuclear oversight observations of poor radworker performance (CR M3-99-1397) indicate a lack of attention to detail.

c. Conclusions

The NRC identified instances of poor contamination control during preparations for Unit 3 refueling outage 6. These observations, coupled with similar, recent nuclear oversight observations, indicate a need for management attention in this area.

R2 Status of Radiological Protection and Chemistry Facilities and Equipment

R2.1 Calibration of Effluent/Process Radiation Monitoring Systems (RMS)

a. Inspection Scope (84750-01)

The inspector reviewed the most recent calibration results for the following effluent/process RMS.

Unit 1:

- Radwaste Effluent Radiation Monitor
- Service Water Effluent Radiation Monitor
- Reactor Building Closed Cooling Water Radiation Monitor
- Main Stack Noble Gas Monitor (Normal and High Range)
- Ventilation Duct Monitor
- Refueling Floor Monitor

Unit 2:

- Clean Liquid Radwaste Effluent Line Monitor (RM-9094)
- Aerated Liquid Radwaste Effluent Line Monitor (RM-9116)
- Steam Generator Blowdown
- Condenser Air Ejector

- Reactor Building Closed Cooling Water Radiation Monitor
- Vent Noble Gas Monitor (RM-8132B)
- Waste Gas Decay Tank Monitor
- Containment High-Range Radiation Monitor

b. Findings and Observations

Electronic alignment and radiological calibration results were found to be within the licensee's acceptance criteria. Linearity tests were appropriate. Operating high voltage was properly set by determining the optimum high voltage set point. Secondary calibrations validated primary calibrations. Tracking and trending efforts were also good.

Due to the extended shutdown, the licensee had not conducted a recent calibration on several RMS, but had these particular RMS calibrations scheduled for conduct prior to restart. These RMS were:

- Steam Generator Blowdown
- Condenser Air Ejector;
- Vent Noble Gas Monitor (RM-8132B);
- Containment Air Monitors (RM 8262B); and
- Containment High-Range Radiation Monitors (RM 8241 and RM8240B).

c. Conclusions

The licensee established, implemented, and maintained an effective RMS program with respect to electronic calibrations, radiological calibrations, system reliability, and tracking and trending.

R2.2 Unit 2 Air Cleaning Systems

The inspector reviewed the licensee's most recent surveillance test results (Visual Inspection, In-Place HEPA Leak Tests, In-Place Charcoal Leak Tests, Air Capacity Tests, Pressure Drop Tests, and Laboratory Tests for the Iodine Collection Efficiencies) to determine the implementation of TS requirements for the following Unit 2 systems: (1) Secondary Containment Enclosure Building Filtration System; and (2) Control Room Emergency Ventilation System.

Deficiencies identified during surveillance testing for the above systems were corrected and as-left conditions met the licensee's acceptance criteria. In summary, the licensee established, implemented, and maintained an effective ventilation system surveillance program with respect to charcoal adsorption surveillance tests, HEPA mechanical efficiency tests, and air flow rate tests.

R6 RP&C Organization and Administration

R6.1 Organization Changes and Responsibilities

a. Inspection Scope (84570-2)

Organization changes that may have affected the implementation of the REMP or MMP and the responsibilities of these programs relative to program oversight were evaluated for the period between January 1998 and April 1999.

b. Observations and Findings

Between second and third quarter 1998, there had been an organization change that had a direct affect on the Radiological Assessments Branch (RAB), Nuclear Engineering (Corporate). RAB was eliminated and the Radiological Engineering Section, RAB (which had responsibilities to implement the REMP) was moved to the Safety Analysis Branch (SAB), Nuclear Engineering. Production Operations Services Laboratory (POSL) continued to collect and prepare REMP samples for analysis. POSL responsibility to support and perform meteorological monitoring instrumentation calibration has not changed. However, calibrations were coordinated with Unit 2 I&C and Environmental Services - Nuclear (non-radiological). SAB assumed responsibility to implement the REMP. Personnel responsibilities have essentially remained the same. SAB has no significant modifications or alterations planned for the program. During self-assessments, SAB identified several areas for improvement during 1998 activities. The issues were documented in the corrective action process.

c. Conclusions

The SAB assumed responsibility to implement the REMP and provided adequate program oversight to meet the requirements specified in the REMODCM. No degradation in program quality or effectiveness was identified.

R7 Quality Assurance in Radiological Protection and Chemistry (RP&C)Activities

R7.1 Quality Assurance (QA) in RP&C Activities

a. Inspection Scope (84750-01)

The inspection consisted of (1) a review of the 1998 QA audit and discussion of 1998 audit responses with chemistry staff; (2) a review of self-assessments; (3) a review of inter-laboratory measurement comparisons; and (4) a review of the chemistry laboratory quality control program for radioactive liquid and gaseous effluent samples.

b. Observations and Findings

The 1998 QA audit covered most aspects of the radioactive effluents control program. Self-assessments helped provide a more performance-based review of the radioactive effluents control program. Especially notable was a review of Unit 1 RMS calibrations by chemistry staff. Responses to audit findings were reasonable.

The Duke Engineering and Service's Environmental Laboratory (DESEL) established a QA Support Program in 1985 to provide test samples for validation of effluent radioanalytical measurements made by the licensee. The QA Support Program consisted of the quarterly distribution of test or quality control samples and issuance of a performance evaluation report. The licensee participated in the QA Support Program. The QA samples were: (1) tritium in water; (2) mixed gamma emitters in water and air filters; and (3) charcoal cartridges. Two hundred and ninety-seven radiological effluent and environmental QC samples were analyzed annually and all measurements were within the licensee's acceptance criteria. Discrepancies were evaluated and resolved by the licensee. No discrepancies of regulatory significance were noted.

Quality control charts for the gamma spectrometry counting efficiency, gamma spectrometry full-width-half-maximum, and tritium counting efficiency were frequently reviewed by licensee staff and used as a mechanism to assess laboratory performance

c. Conclusions

The licensee established, implemented, and maintained an effective quality assurance program for the radioactive effluent control program with respect to audit scope and depth, audit team experience, and response to audit findings. The licensee also implemented an effective quality control program to validate measurement results for radioactive effluent samples.

R7.2 Quality Assurance Audit Program

a. Inspection Scope (84750-2)

The quality assurance audit report (MP-98-A22) of the REMP was reviewed.

b. Observations and Findings

A quality assurance audit was conducted on October 13-23, 1998 by Nuclear Oversight. The audit assessed the licensee's capability to implement the REMP according to TS and REMODCM requirements. The audit was detailed and thorough, in that it evaluated laboratory facilities and equipment, organization and staffing, training, sampling, procedures, and TS reporting requirements. The audit identified strengths and areas for improvement. The areas requiring improvement were assigned to the responsible personnel. The licensee incorporated the issues into the corrective action process, where necessary. The corrective actions were appropriate and effective.

c. Conclusion

The most recent audit of the REMP was detailed and thorough and covered every aspect of the REMP. The audit was sufficient to effectively evaluate implementation and effectiveness of the REMP. The recommendations for improvement were appropriate and corrective actions for areas for improvements were appropriate.

R7.3 Quality Assurance of Analytical Measurements

a. Inspection Scope (84750-2)

The implementation of the QA/QC program of the environmental laboratory, including the Interlaboratory Comparison (cross-check) Program and the licensee's oversight of the laboratories, was evaluated for the period between January 1998 and April 1999.

b. Observations and Findings

The QA/QC program for analyses of REMP samples is conducted by the primary analytical contract laboratory, Duke Engineering & Services Environmental Laboratory (DESEL). The laboratory continued to implement the interlaboratory and intralaboratory QC programs. The intralaboratory QC program consisted of measurements of blind duplicate, spike, and split samples. The results were within the acceptance criteria. The interlaboratory continued to participate in the EPA Cross-Check Program (for drinking water) and the Interlaboratory Comparison Program provided by a vendor (Analytics, Inc.), and several laboratories (for example, Department of Energy (DOE) RESL and DOE EML). The quality control of environmental radioanalyses at DESEL emulated the internal process control program of National Institute of Standards and Technology (NIST). DESEL's participation in these programs was excellent.

c. Conclusion

The REMP quality assurance program was effectively maintained and implemented in accordance with regulatory requirements. The environmental laboratory continued to implement excellent QA/QC programs for the REMP, provide effective validation of analytical results, and conduct the QA/QC programs in accordance with procedures that reflect industry standards and methods. The programs were capable of ensuring independent checks on precision and accuracy of the measurements of radioactive material in environmental media.

R8 Miscellaneous Radiological Protection and Chemistry Issues

R8.1 (Closed) IFI 50-328/98-13-05: Review of Corrective Actions for Adverse Condition Report (ACR) 7615, Section 9.812 of the FSAR, Maintaining a Slight Positive Pressure Against the Unit 1 Turbine Building:

The licensee installed a pressure gauge at the Unit 2 turbine building and monitored the differential pressure. The corrective action for ACR 7615 was completed. The inspectors had no further questions pertaining to this matter.

R8.2 (Closed) LER 50-336/96-34-00: Meteorological Monitoring Instrumentation Inoperable due to Failure to meet Technical Specification Required Minimum Accuracy;

This matter was previously reviewed and dispositioned as a violation (VIO 50-336/98-207-16) and as an NCV (NCV 50-336/98-207-17). The violation was closed on November 18, 1998. Accordingly, this LER is closed.

R8.3 (Closed) LER 50-336/98-021-00: Inadequate Radiation Monitoring of Containment Atmosphere during Refueling Accident;

The inspector performed an on-site review of the licensee's closure package that addressed this Licensee Event Report (LER) 50-336/98-021-00. The evaluation included a review of the licensee's documents to showing closure of the issue, additional applicable documentation, as needed, and interviews of responsible engineering and supervisory personnel. The LER described that the containment gaseous and particulate radiation monitors (RM 8123 A&B, and RM 8262 A&B) may not be able to detect radioactivity released, due to improper air mixing in the containment, during a Fuel Handling Accident in Containment (FHAIC) and isolate the containment purge system to prevent an unacceptable release to the environment. The cause of this LER was the failure to reflect design basis assumptions into operating practices. LER 50-336/98-21-00 is **closed**.

P8 Miscellaneous Emergency Preparedness (EP) Issues

P8.1 (Closed) URI 50-336/90-18-05: Corrective Actions to Develop a Representative Total Dissolved Gas Sample Using PASS; **(Closed - Unit 2 Significant Items List No. 23.7)**

a. Inspection Scope (92904)

An inspection was conducted on April 1-5, 1999 to determine the adequacy of the licensee's corrective actions in response to Unresolved Item (URI) 50-336/90-18-05 and Unit 2 Significant Items List No. 23.7 with regards to the operation of the Unit 2 Post-Accident Sampling System (PASS). The inspection included a review of PASS procedures, surveillance test records, analytical results and interviews with engineering and chemistry personnel. Also, the inspector observed an EP PASS Drill and two PASS surveillance tests.

b. Observations and Findings

The inspector observed the collection of a containment air sample and a reactor coolant sample using the PASS. The containment air surveillance test was performed successfully and the analysis of the reactor coolant liquid sample for radioisotopes, boron, chloride and pH results were satisfactory. However, the licensee was not able to consistently meet the acceptance criteria for a total dissolved gas (TDG) concentration for a reactor coolant liquid sample.

During the inspection, one out of five TDG tests were found to be within the licensee's acceptance criteria (within 10 cc/kg of the known value). However, three of the five were outside the acceptance criteria by a small margin (within 15-20 cc/kg). The system engineer believed that a possible cause was that undissolved gasses were trapped in the liquid sample chamber that were adversely affecting the TDG measurement. The licensee planned to conduct further testing and analyses to ascertain the exact flush volume to eliminate excess gas from the sample line.

On March 23, 1999, the licensee submitted a letter to the NRC referencing the elimination of the "commitment" (NUREG 0737, "TMI Action Plan Requirements," Item II.B.3) for measuring a TDG concentration. (This does not change the licensee's overall responsibility to maintain and operate the PASS; the elimination is specific to a TDG concentration only). The licensee evaluated the change in accordance with 10CFR50.59 and determined that the change did not constitute an unreviewed safety question based on the assertion that TDG is not used for assessing core damage. The inspector reviewed the 50.59 and could not refute the licensee's basis for eliminating the commitment. The licensee stated their intent is to continue to perform the TDG surveillance tests; however, under emergency conditions, doing a TDG concentration will be an "option" to be decided by the licensee's emergency response managers rather than a "requirement".

Revised/approved PASS procedures were found to be detailed and thorough and provided the necessary steps needed for the chemistry technicians to properly operate the PASS. The licensee has provided extensive training on the PASS to five chemistry technicians, four of which were observed by the inspector. They were found to be knowledgeable of the surveillance test procedures and PASS configurations.

The licensee conducted an EP PASS drill in accordance with their E-Plan. The drill adequately demonstrated that a PASS reactor coolant sample could be successfully collected and analyzed within the 3-hour time requirement.

A recent reorganization has combined the Units 2 and 3 chemistry laboratory program under one chemistry manager. Therefore, the licensee plans to manage the PASS program using one technical support engineering team and assigned chemistry personnel. The inspector noted this was a positive initiative, because it assigned ownership to specific personnel in order to provide better management attention and program maintenance. Also, the licensee has added to their Maintenance Rule Plan semiannual testing of sump liquid and quarterly surveillance tests on reactor coolant and containment air for continuing system maintenance.

Subsequent to the onsite inspection, the licensee reported completion of an action item from the 50.59 review. The action was to address necessary changes to the E-Plan with respect to the TDG analysis on a reactor coolant sample. On May 13, 1999, the inspector had a telephone conversation with the EP Manager to discuss the details of the completed action item. The EP Manager stated that a change was made to E-Plan Operating Procedure (EPOP), No. 4447, "Unit 2 Reactor Coolant and Liquid Waste PASS," Attachment 1, with respect to the types of analyses performed on a post accident sample. The word 'optional' was added next to the TDG analysis box. The licensee performed a 10CFR50.54(q) evaluation of the change and determined it did not decrease the effectiveness of the E-Plan.

c. Conclusions

Based on the above review, NRC Unresolved Item 50-336/90-18-05 and Unit 2 Significant Items List No. 23.7 were **closed**. The licensee adequately demonstrated the operation of the PASS. Sample results met the appropriate acceptance criteria and, although the licensee could not consistently meet the total dissolved gas (TDG) acceptance criteria, TDG concentration results were marginally outside the acceptable value. The licensee is continuing to assess the method for retrieving and analyzing a TDG sample for better accuracy. Revised/approved PASS procedures were found to be detailed and technicians were retrained, equipment deficiencies were corrected and the system was repeatedly tested. The licensee adequately demonstrated an Emergency PASS drill and met the time requirement for obtaining post-accident sample results within 3 hours. An unresolved item is being opened for further NRC evaluation of the licensee's method for assessing core damage without the use of a TDG analysis and to review the 10CFR50.54(q) evaluation to determine whether or not the procedure change decreased the effectiveness of the E-Plan. **(URI 50-336/99-05-13)**

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection period. The licensee acknowledged the findings presented.

INSPECTION PROCEDURES USED

IP 37550	Engineering
IP 37551	Onsite Engineering
IP 40500	Effectiveness of Licensee Process to Identify, Resolve, and Prevent Problems
IP 42700	Plant Procedures
IP 60705	Preparation for Refueling
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 84750-01	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 84750-02	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 92901	Followup - Plant Operations
IP 92903	Follow-up - Engineering
IP 92904	Follow-up - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-336/99-05-01	NCV	Inadequate Surveillance Procedure for Testing RPS/ESAS Logic Functions
50-336/99-05-02	NCV	Failure to Adequately Consider the Potential Effects of High Energy Line Break on Safety-Related Equipment Located Outside Containment
50-336/99-05-03	NCV	Incorrect Assumptions in the dc Voltage Drop Calculation
50-336/99-05-04	NCV	Inadequate Main Steam Line Break Analysis Inside Containment Could Result in Exceeding Design Pressure of Primary Containment During Certain Scenarios
50-336/99-05-05	NCV	Potential for Water Hammer, Two-Phase Flow, and Thermally Induced Overpressurization during Postulated Accident Conditions
50-336/99-05-06	NCV	Inadequate Review and Testing of ATI Feature of ESAS
50-336/99-05-07	NCV	Inadequate Pipe Stress Analysis for Main Steam and Main Feedwater
50-336/99-05-08	NCV	Inadequate Accident Analysis for Loss of Normal Feedwater
50-423/99-05-09	NCV	Failure to Perform TS Required Sampling
50-423/99-05-10	NCV	Failure to Perform TS Required Radiation Monitor Check
50-423/99-05-11	NCV	Failure to Perform TS Required Hydrogen Recombiner Channel Calibration
50-423/99-05-12	NCV	Failure to Perform TS Required Fuel Handling Crane Limit Switch Surveillance
50-336/99-05-13	URI	Change of PASS Commitment Regarding Total Dissolved Gas

Closed

50-336/90-18-05	URI	Corrective Action to Develop Representative Total Dissolved Gas Using PASS
50-336/93-19-02	URI	Potential Effects of High Energy Line Break on Safety-Related Equipment Located Outside Containment
50-336/95-01-01	IFI	Generic Letter 89-10 Motor Operated Valve Program
50-336/96-01-05	URI	Containment Hydrogen Monitors and Post Accident Sampling System Inoperable
50-336/96-06-12	EEI	Electrical Equipment Qualification of Solenoid Operated Valves Inside Containment (VIO 50-336/02082)
50-336/96-08-07	VIO	Failure to Perform Surveillance on Certain Containment Isolation Valves
50-336/96-08-09	URI	Effects of SPEC 200 Electronics on the Response Time of the RPS and ESAS.
50-336/96-08-11	EEI	Hydrogen Monitors Rendered Inoperable due to Insufficient Air Flow (VIO 50-336/03062)
50-336/96-08-12	EEI	Failure to Establish Adequate Design Controls for the Steam Generator Replacement Modification (VIO 50-336/01062)
50-336/96-08-13	EEI	Failure to Update the Unit 2 FSAR Regarding the Hydrogen Monitoring System (VIO 50-336/01252)
50-336/96-13-05	IFI	Review of Corrective Actions for Adverse Condition Report 7615, Section 9.912 of the FSAR, Maintaining a Slight Positive Pressure Against the Unit 1 Turbine Building
50-336/96-201-20	EEI	Degraded Environmental Enclosures for Motor Control Centers B51 & B61 (VIO 50-336/02042)
50-336/96-201-28	EEI	Failure to Address the Station Blackout Issues Identified in the Vectra Assessment (VIO 50-336/02092)
50-336/97-02-12	EEI	Numerous Inadequate Surveillance Procedures
50-336/99-05-01	NCV	Inadequate Design Review of the RPS/ESAS Logic Functions
50-336/99-05-02	NCV	Failure to Adequately Consider the Potential Effects of High Energy Line Break on Safety-Related Equipment Located Outside Containment
50-336/99-05-03	NCV	Incorrect Assumptions in the dc Voltage Drop Calculation
50-336/99-05-04	NCV	Inadequate Main Steam Line Break Analysis Inside Containment Could Result in Exceeding Design Pressure of Primary Containment During Certain Scenarios
50-336/99-05-05	NCV	Potential for Water Hammer, Two-Phase Flow, and Thermally Induced Overpressurization during Postulated Accident Conditions
50-336/99-05-06	NCV	Inadequate Review and Testing of ATI Feature of ESAS
50-336/99-05-07	NCV	Inadequate Pipe Stress Analysis for Main Steam an Main Feedwater
50-336/99-05-08	NCV	Inadequate Accident Analysis for Loss of Normal Feedwater

50-423/98-206-05	URI	Restart Items
50-423/99-05-09	NCV	Failure to Perform TS Required Sampling
50-423/99-05-10	NCV	Failure to Perform TS Required Radiation Monitor Check
50-423/99-05-11	NCV	Failure to Perform TS Required Hydrogen Recombiner Channel Calibration
50-423/99-05-12	NCV	Failure to Perform TS Required Fuel Handling Crane Limit Switch Surveillance
50-336/99-05-13	NCV	Inadequate Radiation Monitoring of Containment Atmosphere During Refueling Accident

The following LERs were also closed during this inspection:

50-336/96-018-01	LER	Degraded Environmental Enclosures for Motor Control Centers B51 & B61
50-336/96-24-01 & 02	LER	Inadequate ESAS and RPS Response Time Surveillance Testing
50-336/96-025-00 & 01	LER	Enclosure Building Filtration Actuation Signal/ Auxiliary Exhaust Actuation Signal Interlock Not Periodically Tested
50-336/96-032-00 & 01	LER	Potential Failure of Reactor Coolant System (RCS) Vent to Perform its Design Function
50-336/96-034-00	LER	Meteorological Monitoring Instrumentation Inoperable due to Failure to meet Technical Specification Required Minimum Accuracy;
50-336/96-035-00	LER	Failure to perform Periodic Testing for Interlock Function Associated with the Main Steam Isolation Function of the ESAS.
50-336/97-006-00	LER	Main Steam Line Break Inside Containment Could Result in Exceeding Design Pressure of Primary Containment During Certain Scenarios
50-336/97-007-00	LER	Inadequate Surveillance Procedure for Verifying Operability of Reactor Coolant System Vents
50-336/97-008-00	LER	Insufficient Testing of RPS Logic Circuitry
50-336/97-009-00 &01	LER	Insufficient ESAS Surveillance Testing
50-336/97-015-00 & 01	LER	Potential for Water Hammer, Two-Phase Flow, and Thermally Induced Overpressurization during Postulated Accident Conditions
50-336/97-019-00	LER	Automatic Test Initiator Sends Repeated Trip Signals to the RSST Feeder Breaker Timing Circuit
50-336/97-029-00 & 01	LER	Piping Stress Analysis Performed in Support of IE Bulletin 79-14
50-336/97-031-00	LER	Potential Effects of High Energy Line Break on Safety-Related Equipment Located Outside Containment
50-336/97-037-00 & 01	LER	Service Water Piping Liner Material Lodges in Strainer for the Emergency Diesel Generator Heat Exchangers
50-336/98-012-00&01	LER	Non-conservative Assumptions in the Facility Loss of Normal Feedwater Analysis

50-336/98-021-00	LER	Inadequate Radiation Monitoring of Containment Atmosphere during Refueling Accident
50-423/98-012-00 & 01	LER	Potential Loss of Residual Heat Removal Pumps Due to Minimum Flow Protection
50-423/97-054-00 & 01	LER	Westinghouse Fuel may Exceed 10 CFR 50.46 Maximum Cladding Oxidation Design Criteria
50-423/98-027-00	LER	Unmonitored Flow Path for Injection Cooling Pumps May Prevent Detection of Pump Degradation
50-423/98-013-00	LER	Technical Specification Required Sampling During Mode 5 Not Completed for Steam Generator Drain Down
50-423/98-019-00	LER	IST Acceptance Criteria Do Not Assure that the Design Minimum Check Valve Flows are Obtained
50-423/98-020-00	LER	Daily Check of Radiation Monitor not Performed in Accordance with Technical Specifications
50-423/98-030-00	LER	Historical Event: Channel Calibration of the Hydrogen Recombiners Does Not Meet the Requirements of Technical Specifications
50-423/98-032-00	LER	Missed Fuel Handling Crane Limit Switch Surveillance Test Performance
50-423/98-033-00	LER	Manual Engineered Safeguards Feature Actuation of Motor Auxiliary Feedwater Pumps Due to a Trip of the Motor Driven Steam Generator Feedwater Pump
50-423/98-034-00	LER	Inadequate Evaluation and Retest Replacement Group Rod Indicator Displays

LIST OF ACRONYMS USED

AFW	auxiliary feedwater
AWO	automated work order
AOP	abnormal operating procedures
CFR	code of federal regulations
CO	control operator
CR	condition report
CST	condensate storage tank
DC	direct current
DCM	design change manual
DCR	design change request
DR	discrepancy reports
ECCS	emergency core cooling system
EDG	emergency diesel generator
EOP	emergency operating procedure
ESAS	engineered safeguard actuation system
ESFAS	engineered safety feature actuation system
EWR	engineering work request
FSAR	final safety analysis report
HPSI	high pressure safety injection
HVAC	heating ventilation and air conditioning

ICAVP	independent corrective action verification program
INPO	institute of nuclear power operations
I&C	instrumentation and control
IEEs	item equivalency evaluations
IR	NRC inspection report
IST	inservice test
JUMA	joint utilities management assessment
LER	licensee event report
LOCA	loss of coolant accident
LPSI	low pressure safety injection
MMOD	minor modification
MOV	motor-operated valve
NE	nuclear engineering
NSE	nuclear safety engineering
NRC	nuclear regulatory commission
NU	northeast utilities
OE	operating experience
OD	operability determinations
OP	operating procedure
OPS	operations
OSTI	operational safety team inspection
PASS	post accident sampling system
PDR	public document room
P&ID	piping and instrument drawing
PORC	plant operations review committee
PM	preventive maintenance
PSIG	pounds per square inch gage
PUP	procedures upgrade program
QC	quality control
RAP	NRC Restart Assessment Panel
RBCCW	reactor building closed cooling water
RCS	reactor coolant system
RHR	residual heat removal
RPS	reactor protection system
RWST	refueling water storage tank
SE	system engineers
SIL	significant issues list
SIT	safety injection tank
SM	shift manager
SORC	site operations review committee
SP	surveillance procedure
TM	temporary modification
TS	technical specification
URI	unresolved item report
US	unit supervisor
UT	ultrasonic test

Enclosure 2

Table 1. Aquatic Environmental Sampling Types and Locations

Location	Location Name	Direction/Distance from Release Point	Sample Type
28	Two Tree Island	0.8 Mi, SSE	Mussels
29	West Jordan Cove	0.4 Mi, NNE	Clams
31	Niantic Shoals	1.8 Mi, NW 1.5 Mi, NNW	Sediment, Oysters Mussels
31-X	Niantic Shoals	1.8 Mi. NW	Scallops
32	Vicinity of Discharge	------	Sediment, Oysters, Fish, Seawater, Mussels, Fucus
33	Seaside Point	1.8 Mi, ESE	Sediment
35	Niantic Bay	0.3 Mi, WNW	Lobster, Fish
38	Waterford Shellfish Bed #1	1.0Mi, NW	Clams
39	Jordan Cove Bar	0.8 Mi, NE	Clams
40	Quarry	----	Fish, Oyster, Crabs, Seawater
41	Upper Jordan Cove	1.2 Mi, NE	Mussels

FIGURE 1 to ENCLOSURE 2

AQUATIC SAMPLING LOCATIONS (WITHIN 2 MILES)