U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos.:	50-245	50-336	50-423
Report Nos.:	96-06	96-06	96-06
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: June 27, 1996 - August 26, 1996

Inspectors:
T. A. Easlick, Senior Resident Inspector Unit 1
P. D. Swetland, Senior Resident Inspector, Unit 2
A. C. Cerne, Senior Resident Inspector, Unit 3
A. L. Burritt, Resident Inspector, Unit 1
D. P. Beaulieu, Resident Inspector, Unit 2
R. J. Arrighi, Resident Inspector, Unit 3
J. T. Shedlosky, Senior Reactor Analyst
J. M. Trapp, Senior Reactor Analyst
J. T. Furia, Senior Radiation Specialist
P. M. Peterson, NDE Technician
J. H. Lusher, Health Physicist
G. C. Smith, Senior Physical Security Inspector

Approved by:
Jacque P. Durr, Chief
Projects Branch No. 6
Division of Reactor Projects

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Millstone Nuclear Power Station
Combined Inspection 245/96-06; 336/96-06; 423/96-06

Operations

- A routine review of a Unit 1 operability determination (OD) was performed. The ODs are used to assess degraded plant conditions which affect equipment operability and provide compensatory measures as applicable. Licensed operators were not cognizant of operability determinations that assessed and dispositioned degraded plant conditions. Further, no process or control existed to ensure that licensed operators review and remain cognizant of ODs, including compensatory actions. The failure of licensed personnel to maintain cognizance of degraded conditions which affect operability could adversely impact the ability of the on-shift personnel to assess subsequent equipment degradation. (Section U1.O1.2)

- On June 8, 1996, a small electrical fire occurred in the Unit 1 drywell, which lasted several minutes, and was extinguished with a dry chemical, handheld fire extinguisher. Approximately four hours after the fire was extinguished, a plant equipment operator noticed that the differential pressures across the running standby gas treatment (SBGT) system train were high. The normal ventilation system had been isolated and "B" SBGT was initiated to comply with a technical specification action statement, following the radiation monitoring systems being declared inoperable. After conferring with the Unit Director and the Duty Officer, the Shift Manager elected to unisolate the reactor building, start normal ventilation and secure the running train of SBGT, in an effort to remove or "purge" the remaining dry chemical powder in the drywell atmosphere. However, this action resulted in a deviation from the requirements in Technical Specification 3.2.E.2. This issue is **unresolved** pending further NRC review and inspection. (Section U1.O1.3)

- Unit 2 control of shutdown margin during plant cooldowns differs from the design basis descriptions. Cold shutdown boron concentration is not attained prior to initiating cooldown nor is the shutdown group of control rods "cocked" during the cooldown evolution. The failure to conduct safety evaluations to support these deviations, and update the Final Safety Analysis Report is considered an **apparent violation**. Also, the licensee's practice of injecting unsampled volumes of boric acid into the reactor coolant system during cooldowns was considered unresolved pending further evaluation of the potential for inadvertent (RCS) dilution. (Section U2.O3.1)

- NRC review of 19 licensee event reports (LERs) found them to be generally timely and informative. However, the number of LERs needing supplemental information and the number of missed committed actions indicated weaknesses in the licensee's program for development, review and tracking of events. (Section U2.O7.1)

- Routine operations of Unit 3 in cold shutdown (Mode 5) conditions were well controlled, particularly with consideration of the appropriate shutdown risk criteria. (Section U3.O1.1)

- An audit of the adequacy of Northeast Utilities quality assurance (QA) program by the Joint Utility Management Assessment Team indicated that the audit, surveillance, and inspection programs at Millstone were not effective in the implementation of their Mission Statement and the resolution of identified problems. The team attributed these problems to: lack of support for the QA organization by executive and line management; and the lack of an effective corrective action program. QA effectiveness is a restart issue and a part of the Restart Assessment Plan. (Section U3.O7.1)

- The operation of Unit 3 outside of its design basis resulted from nonconservative piping design and pipe support stress analyses. This deficiency affected independent safety trains in multiple plant systems and is considered an **apparent violation**. (Section U3.O8.3)

Maintenance

- On July 16, 1996, plant personnel were removing a temporary filter assembly from the Unit 1 spent fuel pool when a wire rope, attached to the filter assembly, was entangled with control rods that were suspended from the spent fuel pool equipment rail. This caused five control rods to shift position away from the wall and come to rest against an adjacent spent fuel rack. Six of the eight individuals involved in this evolution were contaminated as a result the filter removal event. They were successfully decontaminated and whole body counts indicated no internal dose was received. During the event, no area radiation monitor alarms were received and no airborne radiation was detected. Following an under water inspection, the suspended control rods were stabilized with additional cables attached to the bottom of the rods and secured to the refueling bridge. The licensee is currently developing a recovery plan. This issue is **unresolved** pending further NRC review and inspection. (Section U1.M1.1)

- Three weaknesses were identified during the Unit 1 intergranular stress corrosion cracking (IGSCC) program review. The IGSCC program lacks detail to prevent inadvertent procedure oversights during ultrasonic testing (UT) examinations and evaluations. The weaknesses are: no method to evaluate unresolved UT indications, no specific UT procedure or calibration blocks for the examinations, and no method to track or trend UT indications from outage to outage. These weaknesses resulted in many UT indications being incorrectly overturned and indications that were found in one inspection, missed in the subsequent inspection. The method used to evaluate Unresolved Indication Reports (UIR's) relies solely on Nondestructive (NDE) Level III expertise. These weaknesses resulted in flawed components being returned to service without performing an engineering evaluation. This is an **unresolved item**. (Section U1.M1.2)

- Unit 2 incorrectly changed the inservice testing program (IST) requirements for high pressure safety injection (HPSI) pump discharge check valves. The licensee appropriately determined that the IST backflow testing of these valves could result in overloading a diesel generator under certain conditions. However, the deferral of the quarterly test requirement to refueling intervals was inappropriate because other mechanisms were available to safely conduct these tests. The issue remained unresolved pending licensee actions to correct the test regime. (Section U2.M8.2)

- The pre-job brief for the loop calibration of the Unit 3 containment recirculation pump flow transmitter was thorough. (Section U3.M1.1)

- The licensee identified licensing basis discrepancies associated with a Unit 3 design change implementing the use of trisodium phosphate as a pH control agent. These issues require resolution prior to plant heatup to mode 4. (U3.M3.1)

Engineering

- A review of a selected group of NCRs, for operability determinations, indicated that the physical control of the NCR process was lost at Millstone Unit 1. The NCR process appears to have been used as an identification process for degraded and nonconforming conditions in the field, contrary to procedure 3.05. The failure of the licensee to properly utilize the NCR process in accordance with procedure 3.05, written to comply with 10 CFR 50 Appendix B Criterion XV, is considered an **apparent violation.** (Section U1.E8.1)

- Unit 2 did not establish a uniform refueling boron concentration in the RCS prior to securing RCPs. This was reasonable because they could not have anticipated the need to perform a core off-load during this mid-cycle outage. However, after identifying the need to off-load fuel in order to repair an unisolable valve, licensee performance in dispositioning this problem was weak in that they planned to drain the RCS to mid-loop when other options involving less risk were available. In addition, PORC did not provide rigorous oversight in approving a TS clarification that redefined "uniform" boron concentration, such that, while meeting the intent of the TS, it would not have complied with the TS as written. (Section U2.E1.1)

- Unit 2 implementation of controls to reduce the potential for draining the reactor cavity during refueling activities was inadequate. One potential non seismic drain path was not isolated nor the consequences of its failure formally evaluated and controlled. The issue is **unresolved** pending further review of licensee commitments regarding this concern. (Section U2.E1.2)

- Unit 2 investigation of potential water hammer events that damaged emergency core cooling system suction piping supports was not timely or comprehensive. More than a year after identification of support damage, the root cause had not been found nor was a comprehensive assessment of

system structural supports completed. The issue remains unresolved pending further review of the cause and corrective actions. (Section U2.E8.1)

- On November 15, 1995, Unit 2 operated for eleven hours at a power level slightly above the operating license requirement, due to erroneous steam generator blowdown flow input into the plant computer calorimetric calculation. This issue remained unresolved pending final licensee control over blowdown flow input, and further NRC review of plant computer programming controls. (Section U2.E8.2)

- Unit 2 discovered that the containment sump screens had been incorrectly constructed such that larger debris than analyzed could pass through to the emergency core cooling systems (ECCSs). This potential common cause failure of ECCSs is considered an **apparent violation** of the technical specifications and corrective action program requirements. (Section U2.E8.4)

- Unit 2 identified seven solenoid-operated valves (SOVs) inside containment whose environmental qualification (EEQ) was incorrect. The valves, which provide containment isolation for various post-accident monitoring and control functions must close on a containment isolation signal, and then are reopened to perform post-accident functions. The licensee had erroneously focused on only the containment isolation functions and concluded that the valves fail-safe. Therefore, EEQ of the SOV circuit was not required. In fact, the post-accident function requires full EEQ of the circuits, and this qualification did not exist for these seven valves. Further, the NRC determined that several other weaknesses in the licensee's implementation of EEQ requirements raise concern with the ability of other components to perform their functions in an accident environment. This issue is considered an **apparent violation**. (Section E2.E8.6)

- The licensee continued to evaluate concerns at Units 2 and 3 related to emergency core cooling system throttle valve flow restrictions and settings. The potential for valve erosion to occur over a period of continuous recirculation flow was considered. This problem, in conjunction with regulatory guidance on containment sump screen sizing, requires the licensee to implement a modification on Unit 3 to install orifice plates in the affected lines. The conduct of licensee corrective measures for these problems is considered an **unresolved item** pending NRC review for effectiveness. (Sections U2.E8.4 and U3.E1.1)

- The root cause investigations and corrective actions taken with regards to selected level "A" and B" adverse condition reports was mixed. The review identified examples of ineffective corrective actions and the failure of the Events Analysis department to identify the discrepancies during their closeout review. (Section U3.E2.1)

- The licensee's failure to correctly translate the technical requirements of the ASME Code, relating to the specification of replacement stud material for the lower flange of the chemical volume and control system letdown heat exchanger, into the design details of a plant design change record represents an **apparent violation** of 10 CFR 50, Appendix B. The premature closure of a nonconformance report, written to track the heat exchanger leakage from the lower flange, may have contributed to the licensee's lack of recognition of this concern as a code compliance problem. (Section U3.E8.1)

Plant Support

- The licensee continues to maintain an effective health physics program, especially during outage operations. General plant radiological housekeeping continues to significantly improve, especially in the Unit 1 turbine building. The Radwaste Remediation Project at Unit 1 continues to make progress in addressing the material condition deficiencies in the Unit 1 liquid waste processing systems and facilities. Continued attention to work planning and work control is necessary for improvement in maintaining occupational exposures as low as is reasonably achievable (ALARA). (Section R1.1)

- Proper foreign material exclusion control was demonstrated and good radiological work practices were demonstrated during retrieval of the fuel handling tool from the spent fuel pool. (Section U3.E2.2)

- On August 5, 1996, an unauthorized entry was made into the Millstone Station protected area (PA) by an administrative contract person. The individual had worked at the station, inside the PA until her previous assignment ended on July 19, 1996. Due to an oversight, she did not surrender her badge and key card upon termination, although her key card had been deactivated. When she arrived at the access control center, a co-worker saw that she was having trouble entering through the access portal and used her own valid key card and hand geometry to allow the individual to enter. The co-worker followed the unauthorized individual into the PA by keying in a second time. This issue is **unresolved** pending completion of the licensee's corrective actions and further NRC review. (Section S1.1)

- Review of the licensee vehicle barrier system, conducted in accordance with NRC Inspection Manual Temporary Instruction 2515/132, "Malevolent Use of Vehicles and Nuclear Power Plants," disclosed that the system was installed and was being maintained in accordance with applicable regulatory guidance and requirements. (Section S8.1)

- On August 13, 1996, representatives of NU, along with their attorney conducted a drop-in meeting with the NRC staff, discussing their Unit 1 radwaste system investigation. NU's review uncovered no evidence that suggests that any member of the NU staff intentionally communicated inaccurate information to NRC inspectors. However, their investigation did indicated problems associated with less than comprehensive answers to those

questions; inadequate management accountability; inadequate establishment of management expectations regarding communications with the NRC and regarding facility conditions; and inadequate closure of a PIR that discussed radwaste conditions. (Section X3.1)

Report Details

Summary of Plant Status

Unit 1 remained in an extended outage for the duration of the inspection period. The licensee continues to review the plant's level of compliance with regulatory requirements, and compliance with their established design and licensing basis, associated with an NRC request pursuant to 10 CFR 50.54(f) and Confirmatory Order.

U1.I Operations

U1.O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Cognizance of Operability Determination

a. Inspection Scope (71707)

A routine review of an operability determination (OD) was performed. The ODs are used to assess degraded plant conditions which affect equipment operability and provide compensatory measures as applicable.

b. Observations and Findings

A copy of a recently issued operability determination (OD), on a potential seismic interaction with control rod blades and spent fuel racks, was requested from the Shift Manager. The Shift Manager had difficulty finding the OD and both the on-duty and the on-coming Shift Managers appeared to be unaware of the disposition of the issue. The inspector determined that neither Shift Manger had reviewed the OD and that in practice ODs, some of which contain compensatory actions, were not being reviewed prior to assuming on shift duties.

Following a discussion with the operations manager and the Unit Director, the Shift Managers were provided the expectation that new ODs would be reviewed prior to assuming watchstanding duties and all ODs with compensatory actions would be reviewed during each shift turnover. Further, the shift turnover checklist was revised to include ODs as a topic of review and discussion. An adverse condition report (ACR) was also initiated to document and track the resolution of this issue. Additional enhancements to the computer tracking tools for system status and procedures such as the "Conduct of Operations" and "Operability Determinations" are planned. The inspectors verified that all ODs with compensatory actions were being reviewed during subsequent shift turnovers.

c. Conclusion

Licensed operators were not cognizant of operability determinations which assessed and dispositioned degraded plant conditions. Further, no process or control existed to ensure that licensed operators review and remain cognizant of ODs, including compensatory actions. The failure of licensed personnel to maintain cognizance of degraded conditions that affect operability could adversely impact the ability of the on-shift personnel to assess subsequent equipment degradation.

O1.3 Fire in Unit 1 Drywell

a. Inspection Scope (93702)

On June 8, 1996, a small electrical fire occurred in the drywell as a result of a poor cable coupling for a ground cable on a piece of welding machinery. The fire was extinguished within minutes by the fire watch and a worker in the vicinity of the welding activity. The fire was extinguished through the application of dry chemicals. The inspectors reviewed this event, as well as the circumstances leading up to the event and recovery activities following the fire.

b. Observations and Findings

On June 6, 1996, the radiation monitoring systems that cause the isolation of normal ventilation systems in the reactor building and initiate the standby gas treatment (SBGT) system were declared inoperable. The radiation monitoring systems were found to be inoperable due to discrepancies with the associated surveillance testing. Technical Specifications (TS) required the calibration of these instruments to include a response time verification, which had never been performed up to this time. With the monitors inoperable, the limiting condition for operation (LCO), required isolation of the normal ventilation systems and initiation of SBGT within 24 hours. The normal ventilation was secured and the "B" train of the SBGT was placed in service in accordance with TS 3.2.E.2. Later that day, the Shift Manager received a preliminary operability determination (OD) documenting the operability of the radiation monitoring systems in the current plant configuration. The LCO was then exited, securing SBGT and placing the normal ventilation system in service.

On June 7, 1996, the inspectors received a copy of "Operability Determination, ACR No. M1960020," written to justify why the radiation monitors were operable. After reviewing the OD, the inspectors discussed the validity of the basis for operability with the Unit Director. The Unit Director agreed that the OD did not provide a valid basis for concluding operability, and informed the inspectors that he would have the Shift Manager declare the radiation monitors inoperable. At 2:30 pm, that same day, the radiation monitoring systems were again declared inoperable, the normal ventilation system was isolated and "B" SBGT was initiated to comply with the technical specification action statement.

On June 8, 1996, a small electrical fire occurred in the drywell, which lasted several minutes, and was extinguished with a dry chemical handheld fire extinguisher. The fire was the result of a poor connection at a cable coupling for a ground cable on a welding machine. Approximately four hours after the fire was extinguished, a plant equipment operator noticed that the differential pressures (D/P) across the running SBGT train were high. The control room operators surmised that the filters in the SBGT train were clogged as a result of the residual dry chemical powder in the drywell atmosphere. The control room operators determined that the D/Ps were unacceptable by comparing the readings to the surveillance test requirements. After conferring with the Unit Director and the Duty Officer, the Shift Manager elected to unisolate the reactor building, start normal ventilation and secure the running train of SBGT. The drywell atmosphere was ventilated using the normal ventilation system for approximately 25 minutes. The "A" train of SBGT was started and normal ventilation systems were secured and isolated. These actions were taken to remove or "purge" the remaining dry chemical powder in the atmosphere via the unfiltered normal ventilation system and thus prevent fouling of the redundant SBGT filter train. However, this action resulted in a deviation from the requirements in technical specification 3.2.E.2.

c. Conclusions

This event is currently under review by the NRC staff. This issue is **unresolved (URI 245/96-06-01)** pending further NRC review and inspection.

U1.O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LER 50-245/96-01: performing work with the potential of draining the reactor vessel during fuel movement. This event was discussed in Inspection Report 50-245/95-42. No new issues were revealed by the LER.

U1.II Maintenance

U1.M1 Conduct of Maintenance

M1.1 Spent fuel Pool Tri-Nuclear Filter Removal

a. Inspection Scope (62703)

On July 16, 1996, plant personnel were removing a temporary filter assembly from the spent fuel pool when a wire rope, attached to the filter assembly, was entangled with control rods that were suspended from the spent fuel pool equipment rail. This caused the control rods to shift position away from the wall and come to rest against an adjacent spent fuel rack. The inspector proceeded to the refuel floor to evaluate the significance of the event and to observe actions taken by the licensee to stabilize the temporary filter and control rods. The inspectors reviewed this event, conducted interviews, inspected associated documentation for the work activities, and evaluated the licensee's root cause analysis for the event.

b. Observations and Findings

On July 16, 1996, maintenance and health physics personnel were attempting to remove a portable "Tri-nuc" filter assembly from the spent fuel pool floor when a 1/8 inch wire rope, attached to the filter assembly, caught on the bottom of three used control rod blades that were stored along the east wall of the spent fuel pool. This caused the control rods to move, resulting in a total of five control rods shifting position, moving away from the wall clustering together, and coming to rest against an adjacent spent fuel storage rack. Upon noticing the control rod movement, maintenance personnel stopped the crane. The "Tri-nuc" filter was suspended at a point were the top of the assembly just broke the surface of the spent fuel pool. The control rods were attached to an equipment rail at the top of the spent fuel pool, each suspended by a cable, and resting perpendicular on the floor of the fuel pool. One of the rods that was caught on the wire was lifted three feet off the fuel pool floor with one end resting close to the fuel pool liner and the other against an adjacent spent fuel rack. The elevation of this rod caused its hook to become disengage at the top of the control rod. The workers made an attempt to reconnect it, but were not successful. After several attempts to untangle the control rods and free the "Tri-nuc" were also unsuccessful, the work was stopped and the workers left the refuel floor and informed plant management.

Six of the eight individuals involved in this evolution were contaminated as a result the filter removal event. They were successfully decontaminated and whole body counts indicated no internal dose was received. During the event, no area radiation monitor alarms were received and no airborne radiation was detected (see section R1.1).

The licensee placed additional rigging on the "Tri-nuc" filter and a cable was placed on the control rod that was no longer attached to its normal suspended cable. The licensee inspected the tangled group of control rods with under water cameras on July 18, 1996, to assess any potential damage to the fuel pool liner, or adjacent spent fuel racks. No damage was identified at that time. Following the under water inspection, the suspended control rods were stabilized with additional cables attached to the bottom of the rods and secured to the refueling bridge. The licensee is currently developing a recovery plan.

c. Conclusions

The NRC is continuing to review this event. At the end of this inspection period, the licensee had not completed its review of the event, and therefore, long term corrective actions have not been initiated. The recovery plan will be finalized once the long term corrective actions are in place. This issue is **unresolved (URI 245/96-06-02)** pending further NRC review and inspection.

M1.2 ISI Program Review

a. Inspection Scope

This inspection was to review and verify the licensees commitment to Generic Letter 88-01 for the augmented, ultrasonic (UT) inspection program.

b. Observations and Findings

The inspector reviewed the licensees response and commitments to Generic Letter (GL) 88-01 "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping." GL 88-01 was issued by the NRC on 1/25/88, to assure that licensees inspection programs conform with Title 10 of the Code of Federal Regulations (CFR) Part 50, Appendix A, General Design Criterion (GDC) 4, 14, 30, 31, and 32.

The inspector selected a sample of component records to verify component categorization, which is based on guidance in GL 88-01 and NUREG- 0313 "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping." The components were categorized by the licensee based on the susceptibility to intergranular stress corrosion cracking (IGSCC). Each category has a different examination schedule. Category A components receive the least frequent examination, 25% of the components examined once every 10 years; Category D components must be inspected every other refueling cycle. Category A components are made from corrosion resistant material and are considered not susceptible to IGSCC. Category D components are considered susceptible to IGSCC. The components selected for review were appropriately categorized, according to GL-88-01 and NUREG-0313.

The inspector reviewed the licensees program for performing augmented UT examinations for IGSCC. Three programmatic weakness were identified. First, the IGSCC program does not specify a methodology to evaluate unresolved UT indications (UIR's). In at least 16 cases, the methodology used to evaluate the UIR's was inappropriate. The indications previously re-evaluated and overturned by the Level III, were later determined to be actual flaws. The examination procedure and calibration blocks for the UT examinations are not specified. Specifying the correct procedure and calibration block may prevent incorrect guidance to perform the examinations. Finally, the IGSCC program does not provide guidelines for tracking and trending UT indications. IGSCC indications were detected in twelve pipe welds during previous inspections, as early as 1984, and not tracked for subsequent inspection. In one case, weld RCBJ-7, four (4) IGSCC indications were noted during the 1987 refueling outage (RFO). In the 1989 RFO, the welds were reported to have no recordable indications (NRI). In 1995, RFO 15, two of the four circumferential indication reported in 1987, were identified and rejected per the American Society of Mechanical Engineers (ASME) Code, Section XI.

One unresolved item in report 50-245/96-01 was that the NDE Level III technician overturned the UT Level II evaluation of IGSCC indications and returned the components to service without an engineering evaluation. The NRC inspector reviewed 12 UIR's from RFO 15 in which the Level II evaluated the indications to be flaws and the Level III re-evaluated the indications as not being flaws, but as being geometrical reflectors. In these cases, the evaluations of the UIR's were appropriate, and were dispositioned using reasonable methods.

During the RFO 15 inspection, thirty five (35) welds were examined containing IGSCC. Fourteen of the 35 welds were previously identified by the UT Level II technician, as early as 1984, as having at least one IGSCC indication, and were subsequently overturned by

the NDE Level III. The disposition of the 35 welds with IGSCC, during RFO 15, was to replace the component or weld overlay the components prior to start-up.

Six reactor coolant components, (RCAJ-2, RCBJ-1A, RRJJ-4, RREJ-4, RRCJ-4 and CUBJ-18) with flaws were placed inservice, between 1984 and 1995, without flaw analysis as required by ASME Section XI, 1986 Edition, Paragraph IWB-3640. The six components were ultrasonically (UT) inspected between 1984 and 1994. During the UT examinations, each component had at least one IGSCC indication. The ASME Section XI analysis was not performed on the components because the UT Level III inappropriately evaluated the IGSCC indications to be geometry The indications were determined to be cracks during refueling outage 15. The licensee performed an evaluation during the November 1995 refueling outage, RFO 15, in accordance with ASME Section XI, 1986 Edition, IWB-3640, to determine the operability of the components. The licensee determined the components did not meet the requirements for continued service and declared the components inoperable. The licensee defined inoperability of a component as a decrease or elimination of the operating safety margin for structural integrity. The licensee determined the safety margin is decreased when a crack through wall dimension in the component is equal to or greater than 75% of the pipe wall nominal thickness.

The six components had intergranular stress corrosion cracks (IGSCC) that were greater than 75% through wall. Two of the six components leaked during preparation for weld overlay. The reactor coolant systems were degraded to the extent a detailed evaluation was necessary to determine system operability. The results of the licensees evaluation determined the six components had an unacceptable structural integrity and a high probability of abnormal leakage.

Five Category D (susceptible to IGSCC) welds (ICBC-F-18, ICBC-F-16, ICBC-F-14, RCAJ-6, and RCBJ-12) were selected for independent ultrasonic examination by the NRC inspector. The welds were recently examined and accepted by NU. NU equipment and UT procedures, MP-UT-2 and NU-LW-1, were used to examine the welds. The results of the licensees examinations closely matched those of the NRC examinations, within the expected tolerances. The NRC inspector detected a UT indication in weld ICBC-F-16 which was not recorded by the licensee. The indication was 1.5" long, approximately 0.10" in depth at 22" from top dead center. The indication information was turned over to the licensee by the NRC for resolution. The licensee investigated the indication with automated UT, manual UT, and radiography. The licensees concluded the indication was caused by inclusions (stringers) in the base material.

c. <u>Conclusions</u>

The components reviewed during the current outage were appropriately categorized for IGSCC susceptibility and examination. The components were categorized based on the guidance provided in GL-88-01 and NUREG-0313. Documentation detailing component categorization was readily available for review by the inspector.

Three weakness were identified during the program review. The program lacks detail to prevent inadvertent procedure oversights during the examinations and evaluations. These weakness resulted in UT indications being incorrectly overturned, and indications detected

in one inspection, being missed in a subsequent inspection. The method used to evaluate UIR's relies solely on the NDE Level III's expertise. These weakness could result in flawed components being returned to service without engineering evaluation.

The UIR evaluation and resolution for RFO 15 was found to be appropriate.

The NRC inspector performed five independent UT examinations selected from Category D components. With the exception of weld number ICBC-F-16, the results of the licensees examination closely matched those of the NRC; within the expected tolerances.

It was determined during the November 1995 refueling outage, RFO 15, six inoperable reactor coolant components, (RCAJ-2, RCBJ-1A, RRJJ-4, RREJ-4, RRCJ-4 and CUBJ-18) were previously placed inservice with unacceptable structural integrity and a high probability of abnormal leakage. The six components had intergranular stress corrosion cracks (IGSCC) that were greater than 75% through wall. Two of the six components leaked during preparation for weld overlay. These flawed welds and the associated weaknesses discussed above are considered **unresolved** pending licensee corrective actions and further NRC review. (URI 245/96-06-**03**)

M1.3 Review of Updated Final Safety Analysis Report (UFSAR) Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description.

While performing the inspection discussed in this report, the NRC inspector reviewed the applicable portions of the UFSAR, Section 5.2.4, that related to the areas inspected. The inspector verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

U1.III Engineering

U1.E8 Miscellaneous Engineering Issues

E8.1 (Closed) Unresolved Item 50-245/96-05-07; Nonconformance Reports

a. Inspection Scope (37551)

A review of the implementation of the licensee's NCR process was performed as it related to control of equipment operability. It appeared that the licensee had used the NCR process, exclusively in some cases, to identify conditions adverse to quality on installed plant equipment (i.e. in field deficiencies) contrary to procedure 3.05, Nonconformance Reports. The NCR process did not require a prompt assessment of operability for these degraded or nonconforming conditions on installed plant equipment. At the end of the previous inspection period, all NCRs had not been dispositioned and assessed for operability. URI 245/96-05-07 was established to review the NCR process.

b. Observations and Findings

The licensee conducted a review of open NCRs assess their impact on system operability. At the time of the review, there was a backlog of 334 open NCRs. Open status was defined as any NCR that was in the review or dispositioned status (i.e. not completed and returned to Quality and Assessment Services (QAS)). The licensee performed an initial line by line review of the data base NCR descriptions to determine if they could adversely affect operability either presently or in the past. This initial review identified 118 NCRs that would require further assessment to determine if there was an operability concern. The licensee identified, early in their review, that they could not easily determine the status of these 118 NCRs since some of the original NCRs could not be physically located. Nuclear Group Procedure (NGP) 3.05, Nonconformance Reports, states that QAS maintains the NCR log which is a hand written log that lists the sequential number, originator, and a brief description of the NCR. Once a number is assigned to an NCR, a copy of the form is made and filed by QAS. A second computerized data base called the Master Tracking Form (MTF), also maintained by QAS, but not addressed by the procedure, is used to track the NCRs to completion.

From late June 1996, until mid July 1996, a search was conducted to account for all 118 NCRs. Of the 118 NCRs reviewed, no NCRs were identified as currently impacting system operability. However, during the review, three NCR numbers were identified as gaps in the accounting system; they did not appear on the open or closed list. There was no physical paperwork associated with these three NCR numbers, nor was there a description or originator listed in the log or MTF data base. Additionally, two adverse condition reports (ACRs) were written during the licensee's review of the NCR process. ACR M1-96-0149 documented a situation where original NCRs were appearing in Work Planning for closure after copies of the NCRs had been previously used to close the same NCRs. Further, investigation by the licensee indicated that the disposition of the original and the copy were different for three of the NCRs. ACR M1-96-0198 documented the fact that an inspection of the open/closed MTF NCR data base when compared with the NCR log, indicated that the MTF data base did not accurately reflect all NCRs.

The inspector performed an independent review of the 118 NCRs for operability impact. While no NCRs were identified as impacting system operability, the inspector noted seven NCRs that were dispositioned, during this review, as having no current impact on operability but would require repair/resolution prior to declaring the systems operable. Since ACRs were not written to account for these NCRs, there is no process controls to ensure all degraded and nonconforming conditions are tracked and corrected prior to restoring systems to an operable status. This weakness was identified in NRC inspection report 96-05, and is currently under review by the licensee. Additionally, the inspector's review confirmed the licensee's practice of using the NCR process to identify conditions adverse to quality on installed plant equipment (i.e. in field deficiencies) contrary to procedure 3.05. NCRs were used to identify such deficiencies as a degraded concrete base beneath a service water pipe support; degraded and leaking resin transfer piping; circulation pump discharge headliner pitting due to corrosion; and wood block shims in the hypochlorite system. NGP 3.05, Nonconformance Reports, section 6.1.1, states that "in the field, the NCR is not used to identify deficiencies but to provide engineering direction to the field when a condition adverse to quality cannot be made to conform to requirements

or when an organization requires engineering direction concerning an identified deficiency. In the field deficiencies are identified by trouble reports, automated work orders, ACRs, surveillance, inspections, or audits." The vulnerability associated with the mis-application of the NCR process is that it circumvents other plant processes, which would provide the controls necessary for prompt operability determinations and to ensure all degraded and nonconforming conditions are tracked and corrected prior to restoring systems to an operable status.

c. Conclusion

The NCR process was used as an identification process for degraded and nonconforming conditions in field contrary to procedure NGP 3.05. 10CFR 50, Appendix B. Criterion XV, Nonconforming Materials, Parts, or Components which do not conform to requirements in order to prevent their inadvertent use or installation. This is an **apparent violation of 10 CFR 50, Appendix B, Criterion XV.** (EEI 245-96-**04**)

Additionally, a review of a selected group of NCRs, for operability determinations, indicated that the physical control of the NCR process was lost at Millstone Unit 1. The licensee plans to review the remaining open NCRs (approximately 200) to account for each NCR, either with originals or copies. At the end of this inspection report period, this had not been completed. Unresolved item **245/96-05-07** is closed, and will be tracked with the corrective actions associated with the foregoing violation.

Report Details

Summary of Unit 2 Status

Unit 2 remained in cold shutdown throughout the inspection period. The unit has been shut down since February 20, 1996, due to uncertainty with the licensee's compliance with the plant design and licensing bases. A comprehensive recertification process is being conducted to support plant restart.

U2.I Operations

U2.O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the licensee's conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

U2.O3 Operations Procedures and Documentation

O3.1 Reactivity Controls During Plant Cooldown

a. Inspection Scope

The inspector noted that on July 7, 1996, operators injected boron into the reactor coolant system (RCS) from the boric acid storage tank (BAST) without first sampling the tank to verify boric acid concentration. The inspector was concerned that changing core reactivity using an unverified boron source could result in an inadvertent RCS dilution.

b. Observations and Findings

While on shutdown cooling, the licensee injected boric acid from a BAST to raise concentration in the circulating portion of the RCS in preparation for a core offload. Only one of the two BASTs is used for this evolution because the other BAST satisfies the technical specification requirement as an emergency boration source. In situations where borating the RCS will require more than the volume of one BAST, it has been the licensee's practice to make batch additions of boron to the BAST while injecting from that tank. Although the initial BAST volume is recirculated and sampled, the BAST concentration is considered unverified following the first batch tank addition. Discussions with operators indicated that batch additions are performed without sampling due to time constraints, particularly during a plant cooldown. Since the RCS is not borated to the cold shutdown concentration prior to commencing the cooldown, boric acid must be added at a sufficient rate to ensure adequate shutdown margin is maintained. The operators contend that adequate shutdown margin can be verified through frequent RCS sampling. They also contend that cooling down in parallel with borating minimizes radioactive waste because the boric acid is injected as coolant volume contracts. In addition, operators stated that

there are sufficient controls in place to prevent dilution due to the fact that the boric acid powder is packaged in QA-inspected, pre-measured bags.

The inspector had several concerns with the licensee's RCS boration practices including: (1) The licensee stated that the batching methods in procedure OP 2304C, "Make Up (Boration and Dilution) Portion of the Chemical and Volume Control System," are designed to maintain BAST concentration between 2.5 percent and 3.5 percent by weight boric acid. This equates to 4371 ppm to 6119 ppm, which is a very wide concentration band. This greatly limits operator control of core reactivity changes. In addition, it allows for an inadvertent dilution due to human error; (2) The Final Safety Analysis Report (FSAR), Section 9.2.3.3, states that "the boron concentration is increased to the cold shutdown value prior to the cooldown of the plant. This is done to assure that the reactor has an adequate shutdown margin throughout the cooldown." However, procedure OP 2207, "Plant Cooldown," Step 4.1.3, states that "it may not be possible in all situations to borate to cold shutdown concentration before commencing cooldown." It is the licensee's normal practice to borate to cold shut concentration concurrently with a plant cooldown, and; (3) FSAR, Section 9.2.3.3, states that "the operator does not insert the shutdown group of [control element assemblies] CEA's until the cooldown is completed and until he verifies the concentration of boron in the reactor coolant by sample analysis." However, procedure OP 2206, "Reactor Shutdown," Step 4.3.3, inserts all control rods in the shutdown group. Procedure OP 2207, Section 2, "Prerequisites," step 2.1.1, specifies that the reactor is shutdown with all control rods fully inserted. The FSAR is also not consistent with Technical Specification 3.1.3.7 which states that the control rod drive mechanisms shall be de-energized in modes 3, 4, 5 and 6 whenever the RCS boron concentration is less than the refueling concentration.

c. Conclusion

10 CFR 50.59, "Changes, Tests and Experiments," states that a licensee may make changes in the facility and procedures as described in the safety analysis report without prior Commission approval, unless the proposed change involves a change in the technical specifications or an unreviewed safety question. Records for these changes must include a written safety evaluation, which provides the basis for the determination that the change does not involve an unreviewed safety question. FSAR Section 9.2.3.3 requires that boron concentration be increased to the cold shutdown value prior to cooldown and that the shutdown group of control rods remain withdrawn until the cooldown is completed and boric acid concentration verified. The failure to prepare a safety evaluation to reflect the changes to the facility implemented in procedures OP 2206 and OP 2207 is an **apparent violation**. **(EEI 336/96-06-05)** These concerns are safety significant in that they constitute a degradation of barriers to the prevention of an inadvertent criticality.

Additionally, control and monitoring of reactivity changes has been the subject of an ongoing licensee and NRC concern. This issue was included in the "Improving Station Performance" Plan to assure sitewide, comprehensive corrective action. The licensee's practice of injecting from the BAST before sampling is not consistent with positive control practices with reactivity changes. This practice should be addressed when responding to the apparent violation.

U2.O7 Quality Assurance in Operations

O7.1 Program for Submittal of Licensee Event Reports

During this inspection, the licensee's program for review and submittal of licensee event reports (LERs) was evaluated by assessing 19 of the LERs submitted for Unit 2 in 1995 and 1996. The reports, in general, were timely and informative, but many required supplemental information because either causal analysis had not been complete or corrective action plans were not finalized. The inspector determined that 3 LERs (95-19, 96-01, and 96-03) contained commitments that were not completed on schedule; and 4 LERs (95-19, 95-41, 96-01, and 96-12) did provide adequate corrective actions to address the event causal factors. These deficiencies are detailed in other sections of this report. The inspector considered the licensee's program for development, review and tracking of LER issues to be weak because these discrepancies were not routinely identified and corrected by the licensee.

U2.O8 Miscellaneous Operations Issues (92700)

O8.1 Update URI 336/95-42-03; Closed LER 50-336/96-01; Reactor Coolant System (RCS) Heatup Rate Exceeded Technical Specification Limit

This event was documented in NRC Inspection Report 50-336/95-44. The licensee identified this occurrence during an event review team (ERT) review of several other incidents involving exceeding RCS heatup and cooldown rates. An engineering evaluation concluded that no adverse consequences to the reactor coolant system occurred as a result of this transient. The LER was supplemented on June 27, 1996 vice April 2, 1996, as committed. The inspector found the LER to be incomplete because it did not discuss why the plant monitoring program for cooldown and heatup rates was inadequate, and what corrective action was implemented to resolve this causal factor. The violations of TS requirements will be evaluated upon completion of the ERT corrective actions and licensee update of the LER. This issue is tracked by unresolved item **URI 336/95-42-03**.

O8.2 Closed LER 50-336/96-02, 03, 04 and 05; Service Water Strainer Backwash System Inadequacies

A common discharge pipe from all the strainer backwash valves froze during cold weather. This rendered both service water systems technically inoperable for 5 hours. These LERs describe a series of deficiencies in system design and operator performance. NRC Inspection Report 50-336/95-44 documents review of the service water strainer inadequacies. Licensee corrective actions were not fully effective requiring subsequent enhancement. Two errors noted in LER 96-02 were subsequently corrected in LERs 96-03 and 96-04. Two corrective actions in LER 96-03, (to implement an operability determination procedure and supplement the LER upon completion of the event review team) were not completed as committed. The NRC is tracking completion of corrective actions and disposition of the potential enforcement actions as **EEI 336/95-44-05**.

O8.3 (Closed) LER 50-336/96-07; Reactor Coolant System (RCS) Cooldown Rate Exceeded the Technical Specification Limit

This event was documented in NRC Inspection Report 50-336/96-01. The licensee identified several prior instances of RCS cooldown rate exceedance during an event review team (ERT) investigation of incidents involving RCS heatup rate exceedance. An engineering evaluation concluded there were no adverse consequences to the cooldown rate exceedance. These prior violations of TS requirements will be evaluated upon completion of the ERT corrective actions. This issue is tracked by unresolved item **URI 336/95-42-03**.

U2.II Maintenance

U2.M1 Conduct of Maintenance

M1.1 General Comments (62703, 61726)

Using Inspection Procedures 62703 and 61726, the inspectors conducted frequent reviews of ongoing plant maintenance. In general, the conduct of maintenance and surveillance activities was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

U2.M8 Miscellaneous Maintenance Issues

M8.1 (Closed) LER 50-336/95-40; Late Surveillance of the Reactor Protection System

On October 22, 1995, the licensee found that the technical specification daily surveillance SP 2601D, "Power Range Safety Channel and Delta T Power Channel Calibration," had not been performed within its required frequency. The surveillance was performed satisfactorily later that day. The late performance of surveillances is discussed in detail in NRC Inspection Reports 50-336/95-38 and 50-336/96-04 and is being tracked by violation 336/95-38-01.

M8.2 (Closed) LER 50-336/95-41; Potential for Emergency Diesel Generator Overload During Surveillance

a. Inspection Scope

The inspector reviewed the licensee's response to LER 50-336/95-41 and evaluated whether their corrective actions satisfied Inservice Test Program requirements.

b. Observations and Findings

Prior to performing procedure SP 21136, "Safety Injection and Containment Spray System Valves Operational Readiness Test," an operator noted the potential to overload an emergency diesel generator (EDG) if a loss of coolant accident (LOCA) and a loss of normal power (LNP) event were to occur while the surveillance was in progress. To perform

backflow testing of the high pressure safety injection (HPSI) pump discharge check valves, the swing HPSI pump is mechanically and electrically aligned alternately to each facility (equipment, devices, cables and raceways have an assigned number that indicates if they are in vital service or not. These numbers are called the "Facility Codes"). This places two HPSI pumps on one facility, rather than the one pump assumed in the EDG loading analysis. If two HPSI pumps were to start at EDG loading sequence 1, generator voltage would dip to 72 percent of rated voltage which is lower than the 75 percent design limit. In addition, the 3250 Kw 300-hour rated load would be exceeded at sequence 3 (3384 Kw) and sequence 4 (3604 Kw). The amount of time that two HPSI pumps are aligned to a single facility is approximately two hours for each facility.

Millstone Unit 2 Second Ten Year Inservice Test Program contains an NRC approved Relief Request No. IWV-6 which allows full stroke testing of the HPSI check valves when the reactor vessel head is removed, because this is the only plant condition where full design flow can be attained. The relief request states that partial stroke exercise of each HPSI check valve will be performed each month. As a corrective action to address the EDG loading concerns, procedure SP 21136 was changed to specify that backflow testing of the HPSI pump discharge check valves would only be performed with the reactor vessel head removed. Refueling Shutdown Justification (RFOJ-004) was prepared to change the Inservice Test Program to address the change in HPSI check valve test frequency. The justification states that "the valves will be partially stroked (open only) quarterly and full stroke exercised (open and shut) during refueling outages when the reactor vessel head is removed. NRC approved Relief Request IWV-6 has previously approved deferring full stroke testing to refueling outages when the reactor vessel head is removed."

The licensee's premise that partially stroked means open only and full stroke exercised means open and shut is inconsistent with the way the NRC and the licensee previously defined these terms. The licensee's Inservice Test Program describes the NRC guidance as stating that it is considered full stroke testing when the flow used is at least that which is identified in the plant's safety analysis. Any less flow used will be considered as a partial stroke unless it can be demonstrated that the lesser flow will still place the valve disk in the same position as the flow in the plant's safety analysis. Therefore, Relief Request IWV-6 addressed the fact that the check valves could only be tested fully open during refueling outages. It did not allow the licensee to perform testing of the check valves in the closed direction only during refueling outages. This is a concern because backflow testing is important to ensure that the design HPSI flow is not diverted through idle pumps.

c. Conclusion

Although NRC NUREG 1482, "Guidance for Inservice Testing at Nuclear Power Plants," allows licensees to make certain changes to their IST program that are consistent with Code requirements, the licensee's basis for changing the back-flow test frequency of the HPSI check valves is not supported by an inability to test the valve during operations. The inspector was concerned that eliminating the quarterly backflow testing was unnecessary because on-line testing can be performed without potentially overloading the EDGs; for instance; by mechanically, but not electrically, aligning two HPSI pumps to one facility. Such a relaxation is neither consistent with the Code nor covered by the approved relief request. The licensee agreed to revise procedure SP 21136 to perform quarterly backflow

testing. This issue is considered **unresolved** to allow the NRC to review the planned changes to this procedure. **(URI 336/96-06-06)**

M8.3 (Closed) LER 50-336/95-42; Late Surveillance of the Off-Site Line Verification

On November 15, 1995, the licensee found that the shiftly technical specification surveillance to verify the alignment of two circuits between the off-site transmission network and the switchyard had not been performed within its required frequency. The surveillance was performed satisfactorily later that day. The late performance of surveillances is discussed in detail in NRC Inspection Reports 50-336/95-38 and 50-336/96-04 and is being tracked by violation 336/95-38-01.

M8.4 (Closed) LER 50-336/95-44; Late Surveillance of the Containment Personnel Air Lock

On November 29, 1995, the licensee noted that the 6-month surveillance for the containment personnel air lock was not performed within its technical specification required frequency. This LER was historical in nature and the surveillance has been satisfactorily performed since this event. The late performance of surveillances is discussed in detail in NRC Inspection Reports 50-336/95-38 and 50-336/96-04 and is being tracked by violation 336/95-38-01.

M8.5 (Closed) LER 50-336/95-45: Plant Shutdown due to Leaking Charging System Valves

On December 14, 1995, Unit 2 was shut down to assess the structural integrity of valve 2-CH-435, a non-isolable valve which provides thermal relief for the charging side of the regenerative heat exchanger. During a containment entry, the licensee found an active body-to-bonnet steam leak on valve 2-CH-435 resulting in a boron buildup around each of the four studs. The leak rate was estimated to be one drop per minute. Machinery history showed that there was no past leakage and no prior maintenance on the valve. The unit was shutdown to evaluate whether stud degradation had occurred as a result of the boric acid buildup. The licensee found the condition of the studs, as well as the valve body, valve bonnet, and seat rings, to be good. The root cause was an original installation error by which the as-found torque on two of the four body-to-bonnet studs was less than the manufacturer recommended torque.

Prior to returning the plant to operation, a sample of 20 similar valves was visually inspected, and no signs of leakage or degradation were found. The licensee stated that this provided assurance that no similar condition existed for other valves. The LER stated that prior to startup from refueling outage RFO 13, the preload on similar valves will be checked. The licensee is now in the process of completing the preload checks for these valves during the current mid-cycle shutdown.

M8.6 (Closed) LER 50-336/96-12; Valve Internals Missing Rendered Safety Function Inoperable

This event involved a missing part in a solenoid valve that controls the position of safety injection valve 2-SI-618. This LER did not address corrective actions for the test program and work control causal factors of this event. A violation of test requirements was cited for this event in NRC Inspection Report 50-336/96-04. The licensee committed to supplement the LER by September 25, 1996.

U2.III Engineering

U2.E1 Conduct of Engineering

E1.1 Reactor Coolant System Boron Concentration to Support Core Off-Load

a. Inspection Scope

The inspector evaluated the licensee's plans to attain the required boron concentration in the reactor coolant system (RCS) to support a full core off-load. During a normal shutdown and cooldown, if fuel movement is planned, the licensee borates the RCS to the refueling concentration while the reactor coolant pumps (RCPs) are operating. This mixes the boron throughout the RCS, and satisfies Technical Specification (TS) 3.9.1 which requires that when the reactor vessel head is unbolted or removed, a uniform and sufficient boron concentration shall be maintained in all filled portions of the RCS and the refueling canal. Uniform and sufficient concentration (1730 ppm) is needed to ensure that the reactor remains shutdown (without control rods) during the refueling process. Since the licensee did not intend to off-load the core when the unit was shut down, the RCS was borated to only 1320 ppm to satisfy shutdown margin requirements for mode 5. The RCPs were secured and shutdown cooling was initiated. After the shutdown, the licensee found that the core must be off-loaded to effect repairs of a safety injection valve. Since the shutdown cooling system takes suction from the #2 hot leg and injects into all four cold legs, large portions of the hot and cold legs, as well as the steam generators and RCPs, are not circulated (and thereby mixed) by the shutdown cooling system. Therefore, the licensee evaluated methods to achieve the TS required uniform boron concentration in all filled portions of the RCS.

b. Observations and Findings

On June 3, 1996, the licensee submitted to the NRC a proposed one-time revision to TS 3.9.1 that would strike the words "of all filled portions" and "uniform." In addition, a footnote was proposed stating that for this Cycle 13 mid-cycle outage, it was acceptable for boron concentration in the steam generators and unmixed portions of the hot and cold legs to initially be as low as 1300 ppm. The technical basis for the proposed change concluded that if the shutdown cooling system was borated to greater than 1820 ppm, the entire RCS would remain above the TS required concentration (1730 ppm), even if all the water in the loops were at 1400 ppm boron and were mixed with the shutdown cooling system water. The licensee would achieve the increase in boron concentration in the loops from 1320 to greater than 1400 ppm by a partial drain and refill of the loops. To minimize

any stagnant volume of RCS water at 1300 ppm, the licensee planned to refill the RCS from the refueling water storage tank using the "B" charging pump which would pump water through temporary hoses to an instrument tap on each of the four cold legs. Using this method, it was possible that the subsequent samples would show that all filled portions of the RCS were uniformly above the refuel boron concentration. Thus, the potential existed that this evolution could eliminate the need for the TS change.

On June 19, 1996, the inspector attended a plant operations review committee meeting (PORC) in which a change to the Unit 2 Technical Requirements Manual was approved which involved a clarification to TS 3.9.1 to better define the term "uniform." The licensee planned to use this clarification to assess RCS samples that would be taken following the draining and refilling evolution. The clarification recognized that some engineering judgment is involved in determining whether the boron concentration is uniform because: 1) The TS provides no tolerance range for the term uniform; and, 2) boron concentration sample results have a margin of error of approximately 10 ppm. The TS clarification stated that a "uniform" boron concentration is attained when all filled portions of the RCS and refuel pool are greater than the required refueling boron concentration. The bases for the clarification states that the "intent" of uniform in TS 3.9.1 is to ensure that the RCS and water volumes having direct access to the reactor vessel and core are maintained greater than the required refueling boron concentration.

The NRC noted that the licensee's clarification of the term uniform was too broad. The TS clarification allowed boron at various RCS sample locations to differ greatly (for example 500 ppm or more) but would still satisfy the licensee's definition of "uniform" as long as the samples were all above refueling boron concentration. The TS clarification was unacceptable because samples with large differences in boron concentration could not reasonably be considered uniform. Although a non-uniform RCS is not a safety concern as long as all portions are maintained above the refueling boron concentration, the TS requirements regarding uniformity must be satisfied until such time as a TS change is approved. The licensee did not implement the approved TS interpretation.

The inspector also evaluated the licensee decision to drain the RCS to mid-loop. This activity is considered one of the highest shutdown risk evolutions due to an increased possibility of losing shutdown cooling, a shorter time to boil, and a reduced water volume above the core. Although there is currently no regulation that requires the licensee to avoid mid-loop operation, the licensee should have a sound justification why using mid-loop operation is the best option available, especially considering the fact that the "B" emergency diesel generator was inoperable and the shutdown cooling system was degraded by the stuck-open loop isolation valve. The licensee stated that the primary reason for draining to mid-loop was to attempt to satisfy the existing TS requirements, and thus eliminate the time needed for the TS amendment process.

Following discussions with the NRC, on July 3, 1996, the licensee submitted to the NRC another revision to TS 3.1.9 that proposed an alternative plan. The licensee proposed to raise SDC volume boron concentration to greater than 1950 ppm, and borate the reactor vessel head area by lowering level in the vessel to 1 to 3 feet below the flange (above the defined reduced inventory precaution conditions), and refilling with water greater than 1850 ppm boron. This method did not involve mid-loop operation, and eliminated the need

for temporary hoses to circulate water into idle portions of the RCS loops. While awaiting NRC approval of the proposed TS change, the licensee borated the SDC volume to greater than 2100 ppm. Various RCS sample results indicated substantial diffusion or mixing of boron into the idle loops. However, strict uniformity of the samples was not achieved. On August 13, 1996, the NRC approved a one-time TS change to allow entry into the refueling mode without uniform boron concentration. At the end of the inspection period, the licensee was finalizing plans for the full core offload.

c. Conclusion

The fact that the licensee did not establish a uniform refueling boron concentration in the RCS prior to securing RCPs was reasonable, because they could not have anticipated the need to perform a core off-load. However, the licensee safety perspective in dispositioning this problem was not conservative in that they planned to drain the RCS to mid-loop when other options involving less risk were available. In addition, PORC did not provide rigorous oversight in approving a TS clarification that redefined "uniform" boron concentration, such that, while meeting the intent of the TS, it provided so much latitude that it would not have complied with the TS as written.

E1.2 Refueling Pool Drain Line

a. Inspection Scope

On July 11, 1996, the licensee prepared an adverse condition report (ACR) that addressed the fact that non-seismic piping was connected to the refueling pool drain header that was not isolated from the header during refueling. The inspector evaluated the licensee's response to the ACR to determine if it was consistent with their response to NRC Bulletin 84-03, "Refueling Cavity Water Seal."

b. Observations and Findings

There are two 4-inch refueling pool drain lines each containing a manual isolation valve (2-RW-123 & 124). The two drain lines join to form a common 4-inch header that directs water outside containment to the suction of the refueling water purification pumps. The refueling water purification pumps can discharge through an ion exchanger back to the refueling pool or they can discharge to the refueling water storage tank to drain the refueling pool. Between valves 2-RW-123 & 124 and the containment penetration, there is 31 feet of piping that is seismic Class II (non-seismic).

Procedure OP 2305, "Spent Fuel Pool Cooling and Purification System," states that the purification system should be operated continuously during refueling and accordingly, specifies opening valves 2-RW-123 & 124. The ACR addressed the fact procedure AOP 2578, "Loss of Refuel Pool and Spent Fuel Pool Level," does not specifically state that valves 2-RW-123 & 124 should be verified closed if a decrease in refueling pool level is observed. Instead, procedure AOP 2578, states that "if conditions allow, verify that a cavity drain line has not failed." Another concern was that access was difficult because the valves were 13 feet above the floor. As corrective actions, the licensee planned to change procedure AOP 2578 to specify closing valves 2-RW-123 & 124 in the event of an

unexpected decrease in refueling pool level. They also planned to specify the location of the valves and how to access them.

The inspector was concerned that operator actions were being used to compensate for the fact that a portion of the drain line was not seismically qualified. In addition, the licensee's response to NRC Bulletin 84-03 was based on the premise that valves 2-RW-123 & 124 would remain closed thereby eliminating the need for operator actions. This was confirmed by the engineer who prepared the design modification that upgraded the drain line piping from the refueling pool to valves 2-RW-123 & 124 to seismic class 1. This explained the lack of specificity in procedure AOP 2578 regarding the need to close the isolation valves.

The failure to specify that valves 2-RW-123 & 124 would remain closed during refueling operations is a concern because: (1) Following a seismic event, maximum flow through a broken drain line would be approximately 1500 gpm. The licensee had no evaluation to demonstrate that operators would have sufficient time to close the valves or whether operators could even reach the valves with a nearby 1500 gpm leak; (2) Although the flow rate through a broken drain line is less than the 6490 gpm flow rate associated with a reactor cavity seal failure, the consequences are significantly worse because a cavity seal failure would drain the refueling pool to the reactor vessel flange while a drain line failure would also drain the south saddle and transfer canal. In addition, a drain line break would also release a larger volume of water to the containment than is assumed in the loss of coolant accident analysis which could result in the submergence of essential equipment. The licensee had no evaluation that addressed this larger volume of water and no procedure describing operator actions to be taken.

More importantly, drainage of the south saddle and transfer canal eliminates these areas as safe fuel storage locations. With a cavity seal failure, three fuel assemblies could be safely stored in the south saddle area of the reactor cavity (two in the upender and one on the refueling machine in its full down position.) However, drainage of the south saddle and transfer canal following a drain line break would expose these fuel assemblies which would greatly increase radiation levels and possibly result in fuel damage. Procedure AOP 2578, Step 3.6 states that a refueling cavity drain line failure in the south saddle would drain that area completely and would eliminate this area and the transfer canal as a safe storage location. However, Step 4.3.3, only verifies that a cavity drain line has not failed "if conditions allow." This step is inadequate in that it does not reflect that this verification is crucial in determining a safe fuel storage location.

Since the licensee's bulletin response was written with the presumption that valves 2-RW-123 & 124 would remain closed, procedure AOP 2578 does not address the failure of non-seismic refueling purification system piping and components outside containment. This scenario is safety significant because it could result in reactor coolant leakage outside the containment that would not be available for recirculation.

Since procedure AOP 2578 specifies that containment be evacuated once the fuel assembly is lowered to a "safe" location, operators would not be inside containment during the approximately 1¾ hours that would be available to determine a drain line break had occurred. The safe locations with a drain line break are the core and the transfer carriage after it is moved to the spent fuel pool and the transfer tube isolation valve is closed.

Procedure AOP 2578 states that it takes approximately 50 minutes to completely close this valve.

Although it is not mentioned in the licensee's bulletin response, the north saddle of the refueling pool would also drain in the event of a drain line failure. Even if fuel assemblies were safely stored, completely uncovering the reactor upper guide structure or lower internal components that could be stored in the north or south saddle could significantly increase radiation levels.

The inspector discussed the above concerns with licensee management who agreed to danger tag closed valves 2-RW-123 & 124 during the upcoming refueling operations. The licensee plans to utilize the submersible filtration unit that they normally use for refueling pool purification and clarification.

c. Conclusion

The refueling pool drain line issues that are discussed above are considered **unresolved** pending further NRC review of the licensee's disposition of these concerns. **(URI 336/96-06-07)**

U2.E2 Engineering Support of Facilities and Equipment

E2.1 Core Tilt Evaluation

a. Inspection Scope (37550)

The inspector reviewed the core tilt technical specification surveillance tests for fuel cycles 12 and 13. The inspection focused on the actions taken in response to a tilt anomaly that occurred at approximately 10,000 megawatt days per metric ton of uranium (MWD/MTU) burnup during cycle 12 operation. The azimuthal power tilt is the maximum difference between the power generated in any core quadrant and the average power of all quadrants, divided by the average power of all quadrants of the core. The azimuthal power tilt was determined by using the fixed incore flux detector system and the INPAX incore analysis computer code.

b. Observations and Findings

A graph of the azimuthal power tilt as a function of core burnup was documented in calculation C12-01181-F2, Rev. 0, March 2, 1995, "Millstone Unit 2 Cycle 12 Incore Data Analysis." The azimuthal power tilt was approximately .01 for fuel burnup ranging from 0-10,000 MWD/MTU, with the largest tilt located in the upper half of the core. At a burnup of approximately 10,000 MWD/MTU, the tilt began to slowly increase. The maximum measured tilt was approximately .017, at 12,000 MWD/MTU. The azimuthal tilt then slowly decreased to approximately .012 for the duration of cycle 12. The incore azimuthal tilt angle moved from approximately the 75 degree angle to the 328 degree angle during cycle 12. The rate of change of the azimuthal tilt angle began to accelerate at about 8,000 MWD/MTU. Technical specification 3.2.4 requires that the azimuthal power tilt not

exceed .02, in mode 1, at power levels greater than 50% power. The azimuthal power tilt did not exceed the technical specification requirement during the cycle 12 transient.

An evaluation of potential causes for the increase in azimuthal power tilt was documented in attachment 2 to calculation C12-01181-F2. An evaluation of the fixed incore detector response data indicated that the tilt was not the result of instrumentation or calculational errors. The evaluation concluded that fuel assembly RW-15 was the most likely cause for the tilt. Fuel assembly RW-15 was a reconstituted fuel assembly that contained 5 stainless steel pins in place of fuel rods. This conclusion was largely based on the observation that the peak quadrant power rotated to the quadrant that contained fuel assembly RW-15. This conclusion was not confirmed by a more detailed core analysis, which concluded that fuel assembly RW-15 could not cause the magnitude of tilt observed.

A Plant Information Report (PIR) 2-94-059, "Azimuthal Power Tilt Increasing" (dated 2/11/94), was written to initiate a root cause evaluation for the higher than expected azimuthal power tilt. The root cause evaluation for the PIR was performed by Reactor Engineering, Nuclear Fuels Engineering and the fuel vendor. Several potential causes were evaluated including improper instrument operation, misloading of the burnable poison, and a separated control rod finger. The investigation was unsuccessful in identifying a root cause. The PIR was closed on July 18, 1994, with no recommended corrective actions.

A full core computer design code was used to evaluate the potential causes for the tilt. The steel pins in the reconstituted fuel assembly RW-15 and misloading of the burnable poison (gadolinium) were both evaluated as potential causes for the tilt. The burnable poisons were suspected because the gadolinium poison was expected to burnout at approximately the core burnup where the tilt increase occurred. The results of the analysis (Memorandum, "MP-2 Cycle 12 Core Radial Power Tilt," dated February 10, 1995) were inconclusive. Both the steel pins and burnable poison misloading predicted a change in the azimuthal tilt angle similar to that experienced during the tilt transient; however, the magnitude of the tilt was much less than the measured tilt. The fuel vendor verified that there was no misloading of burnable poisons by reviewing manufacturing records. The fuel vendor was also unable to identify a root cause for the observed increase in tilt.

c. <u>Conclusions</u>

The peak azimuthal tilt did not exceed technical specification limits during cycle 12 tilt transient. The plants accident analysis is valid for azimuthal tilt values less than the technical specification limit. The root cause for the increase in the tilt was not identified. The initial determination that the reconstituted fuel assembly was the most likely cause of the tilt was not substantiated by further analysis. The inspector concluded that the credible causes for the increase in tilt were thoroughly evaluated and the depth of the root cause analysis was appropriate.

E2.2 Estimated Critical Rod Position Calculations

a. Inspection Scope (37550)

The inspector reviewed the cycle 12 and 13 estimated critical rod position (ECP) calculations to ensure compliance with technical specification requirements. The ECP is a reactivity balance used to estimate the boron concentration and control rod position where criticality will be achieved during reactor startups. The actions implemented to improve the accuracy of the ECP calculations were also reviewed.

b. Observations and Findings

The ECP reactivity calculations are performed in accordance with Operating Procedure OP-2208, Rev. 11, "Reactivity Calculations." Technical specification 4.1.1.1.2 requires that the actual critical reactivity be within 1% delta-k/k of the predicted value. Operating Procedure OP-2208 conservatively requires that criticality be achieved within .9% delta-k/k of the ECP prediction. The inspector reviewed the cycle 12 ECPs. In all cases the technical specifications and the administrative limits of OP-2208 were satisfied. However, the licensee was not satisfied with the magnitude of disagreement between the actual and predicted ECP values and implemented actions to improve the accuracy of the ECPs.

A Plant Incident Report (PIR) 2-93-101, dated May 25, 1993, was written to document a cycle 12 occurrence where criticality was not achieved prior to the control rods being fully withdrawn. The immediate corrective actions were to validate the ECP calculation and the input data. Following validation, the Reactor Engineering staff calculated a new ECP, boron concentration was reduced, and the reactor criticality was achieved. The reactor reached criticality approximately 10 hours following the original startup attempt. The failure to establish criticality prior to the control rods being fully withdrawn was an operational inconvenience; however, at no time during this startup were technical specification 4.1.1.1.2 or associated administrative requirements exceeded.

In response to this PIR, the Nuclear Analysis Section provided several recommendations to improve the ECP calculations and operating procedure (Memorandum, "Plant Incident Report 2-93-101," dated July 27, 1993). The recommendations were to use revised power defect curves and to ensure adequate control rod bite when calculating ECPs for high xenon startups. Operating Procedure 2208 was revised to implement these recommendations. The corrective actions were successful in preventing similar occurrences during the remaining cycle 12 startups. A human error in performing an ECP calculation was determined to be the cause of a cycle 13 occurrence where criticality was not achieved prior to the control rods being fully withdrawn (Adverse Condition Report 04601).

The Nuclear Analysis Section staff continued efforts to improve the accuracy of the ECP calculations. On April 28, 1994, an improved ECP methodology (Calculation W2-517-405-NA, Rev. 0) was submitted to Nuclear Fuels Engineering (NFE) management for review and approval. The calculation recommended improvements for calculating ECPs. The ECP enhancements were to: (1) revise certain constants used by the core design computer models; and (2) use the unbiased boron concentration for the hot full power (HFP) and hot

zero power (HZP) conditions. The "best estimate" critical boron concentration includes a boron bias which is used to correct for inaccuracies in the boron concentration predicted by the core design computer codes. These recommendations were also provided to site Reactor Engineering for review (Memorandum, "Estimated Critical Position Calculations for MP 2 Cycle 12," dated April 28, 1994).

The proposed calculation file and recommendations were not approved by the NFE manager (Letter, "Proposed Calculation W2-517-405-NA and Associated Memo," dated July 12, 1994). The reasons stated were: (1) inadequate quality assurance review in changing the fuel vendor's core design computer model; and (2) the desire not to bias ECP predictions using past ECP errors. The NFE manager recommended an effort be initiated to enhance the fuel vendors core design models. Reactor Engineering also concluded that the recommended changes could not be used to improve the ECPs (Memorandum, "Estimated Critical Position Calculations for MP2 Cycle 12," dated August 16, 1994).
The licensee fuels engineers efforts to improve the ECP accuracy continued throughout 1994-1995. On November 15, 1995, the fuel vendor provided a revised Startup and Operations Report ("Transmittal of Millstone Unit 2, Cycle 13, Startup and Operation Report, EMF-94-201(P), Rev. 1 and Updated XTGPWR Deck") which used the latest neutronics design methodology. The primary improvements were: (1) finer depletion steps for the gadolinium cross sections; and (2) more accurately reflecting the full power fuel temperatures. The methodology also reflected, to a lesser extent, the core design code improvement recommended in calculation W2-517-405-NA. A significant improvement in the accuracy of the ECPs was demonstrated using the revised analysis.

c. Conclusions

The cycle 12 and 13 ECPs reviewed complied with technical specification and administrative requirements. The licensee's corrective action to improve the ECPs by improving the core design codes was a technically sound approach to resolve this issue. The basis for rejection of the recommended ECP methodology changes using the unbiased boron concentration was appropriately documented and justified. The inspector concluded that the actions taken to improve the ECP calculation accuracy were appropriate.

E2.3 Boron Biases

a. Inspection Scope (37550)

The licensee identified a concern that the boron biases may have an adverse effect on the core safety analysis. The inspector reviewed the actions taken to evaluate and resolve this concern.

The "best estimate" boron concentration, used in certain core safety analyses and startup physics testing, included a boron bias. The boron bias was the difference between the measured hot full power (HFP) boron concentration and the predicted boron concentration as calculated during past cycles. The predicted boron concentration was calculated using computer core design models. The "best estimate" boron concentration was equal to the sum of the boron bias and the predicted boron concentration. The boron bias was added to compensate for consistent inexactness in the computer core design models.

b. Observations and Findings

The magnitude of the biases used in the prediction of HZP and HFP critical boron concentrations for cycle 13 ranged from 55 to 80 parts per million (ppm) boron. A Nuclear Fuel Section (NFS) Engineer outlined several safety concerns regarding the boron biases (Memorandum, "Concern of Large Biases in Predicted MP 2 Critical Boron Concentrations," dated September 21, 1995). The primary concerns were that: (1) the boron biases may have an adverse effect on the plant safety analysis; and (2) the acceptance criteria used in the startup physics testing, which uses the "best estimate" values, appears to be inconsistent with the users guide provided as Appendix A to American National Standards Institute/American Nuclear Society (ANSI/ANS) standard 19.6.1-1985, "Reload Startup Physics Tests for Pressurized Water Reactors."

The NFS Supervisor provided a preliminary response to these concerns (Memorandum, "Preliminary Evaluation - Large Boron Biases at MP2," dated October 5, 1995). The preliminary response stated that the main impact on the safety analysis would be the boron concentrations used to analyze the boron dilution events and for shutdown margin calculations. The fuel vendor confirmed that the same boron biases are applied to the safety analysis calculations. The other potential effect boron biases could have on the safety analysis was a perturbation of the radial power distribution. The evaluation concluded that the affect on the radial power distribution was not large enough to be a safety concern.

The preliminary response also addressed the concern with the apparent deviation from the ANSI/ANS standard. The response stated that Millstone Unit 2 used the standard as a general guideline, but were not committed to conduct core physics testing in accordance with the standard. They also noted that the recommendation to use the unbiased boron concentrations for physics testing was provided in the optional part of the standard. The evaluation stated that in an upcoming revision to the standard, a current proposal is to reverse this position and use the "best estimate" boron concentrations for comparisons during physics testing. The response stated that the fuel vendor recommended using the "best estimate" values for the core physics testing (Letter, Millstone Reactivity Biases, dated October 2, 1995).

An evaluation of the effect of the boron bias on the safety analysis was conducted by the engineer who originally identified this concern (Memorandum, "Review of the MP 2 Cycle 13 Safety Related Analyses," dated December 12, 1995). The evaluation assessed the effect of the boron bias on power distribution affected parameters, shutdown boron concentration, and the boron dilution transient analysis. The conclusion of this evaluation was that using the best estimate boron concentration for certain safety analyses and for conservatism in the shutdown boron concentration adequately compensate for the inaccuracy in the predicted boron concentrations. The conclusion was that the inclusion of the boron bias did not result in significant changes in safety-related parameters. The overall conclusion was that the results of the cycle 13 safety analyses and the shutdown boron concentrations remain valid.

c. Conclusions

The inspector concluded that the licensee had conducted a thorough evaluation of this concern. The evaluations demonstrated that the safety analyses for cycle 13 were not adversely affected by the inclusion of boron biases. The basis provided for using of the "best estimate" boron concentrations as the predicted values for core physics testing was acceptable. The detail and timeliness of the evaluations of this concern were commensurate with the potential safety significance of this issue.

U2.E8 Miscellaneous Engineering Issues

E8.1 (Closed) LER 50-336/95-19; Shutdown Cooling System Inoperable due to Damaged Snubber Support

a. Inspection Scope

The inspector evaluated the licensee's disposition of failed snubbers on the suction header of the facility 1 emergency core cooling system (ECCS) pumps.

b. Findings and Observations

On May 14, 1995, with the unit shut down, a hydraulic snubber support assembly on the facility 1 ECCS suction header was determined to be inoperable due to a significantly bent extension rod. In addition, the hydraulic snubber had rotated on its axis causing its hydraulic fluid supply reservoir to be located below the valve assembly. On May 11, 1995, a trouble report had been written to address that hydraulic fluid had been observed leaking from the vent port. The shutdown cooling (SDC) system was declared inoperable after 72 hours had passed without evaluation of the deformed snubber assembly. The SDC system was appropriately declared inoperable, however, the system remained in operation to remove decay heat from the reactor.

The licensee event report (LER) stated that the root cause of the event was being investigated to determine the origin of the load that bent the extension rod. The licensee was investigating both water hammer and external loads as potential causes. The initial corrective action was to repair the snubber assembly to restore SDC system operability. The LER stated that additional corrective action will be determined based on the results of the root cause investigation that was underway and that this would be reported in a supplement to the LER.

The inspector had three concerns with the LER: (1) The licensee has yet to meet their commitment of submitting a supplement to the LER to discuss the results of the root cause investigation; (2) The root cause investigation has not been completed even though the event occurred more than 14 months ago; and (3) the LER did not specify a date that their planned corrective action would be completed.

The licensee stated that the root cause investigation is ongoing because they have been unsuccessful in definitively determining the cause of the damaged snubber. Their investigation revealed that in addition to the hydraulic snubber, a mechanical snubber on

the same line was also damaged. Evaluations of various scenarios such as starting pumps and operating valves showed that the resulting water hammer forces would be insufficient to cause the observed damage to the two snubbers. The inspect - informed plant engineering that operators had related that when the motor-operated valve at the RWST is opened to fill the ECCS suction header, it "rattles the roof," indicating the magnitude of the water hammer. The licensee stated that system fill was one of 7 scenarios considered but was not pursued because of engineering judgement that the system fill would not provide sufficient force. Plant engineering stated that they met with operations personnel and there was no mention of the significant water hammer that has occurred during previous ECCS suction header filling. Also, a more recent adverse condition report addresses a piping support base plate near the RWST that had two bolts pulled out from the wall. This provides additional evidence of significant transients in this system.

c. Conclusions

At the end of the inspection period, the licensee had not yet completed calculations to confirm whether the system fill could be the cause of damaged snubbers. They also plan to perform detailed walkdowns of piping supports of both ECCS suction headers to evaluate the current condition of the supports in the ECCS suction piping. The timely completion of the licensee's evaluation of the current system status, the determination of the root cause, and implementation of corrective actions are important due to the potential for inoperable supports to render all ECCS pumps in both trains inoperable. Resolution of the water hammer issues, as well as the concerns associated with the LER commitments are considered **unresolved**. **(URI 336/96-06-08)**

E8.2 (Closed) LER 50-336/95-43: Reactor Core Thermal Power Level Exceeds License Limit

On November 15, 1995, the reactor core thermal power level exceeded the maximum power level permitted by the operating license (2700 megawatts thermal). The core heat balance calculation had been performed using an incorrect value for steam generator blowdown flow rate. This resulted in the calculated core thermal power being less than the actual core thermal power. The license limit was exceeded for approximately 11 hours. A best estimate of the maximum steady-state power level achieved during this period was 2709 megawatts thermal (approximately 100.33 percent power). The inspector reviewed computer records to verify that the licensee's immediate corrective action to input an acceptable blowdown flow rate value into the calculation had been completed. This issue is considered **unresolved** pending further review of the final resolution of blowdown flow input, and evaluation of the control and validation of plant computer calculations. **(URI 336/96-06-09)**

E8.3 (Closed) LER 50-336/96-06; Service Water Pump Design Vulnerable to Flood Water

Technical Specifications require that one service water pump be protected from flood waters when severe storm conditions threaten. This assures that at least one pump will be operable for use after the flood conditions subside. The Unit 2 service water system flood protection design provides protection for only the "B" or "C" service water pump. The licensee determined that there had been outage periods when neither the "B" nor "C" pump remained operable such that they could have been protected for use after a flood. During these periods, however, no severe weather conditions were experienced. In response to this design deficiency, the licensee implemented administrative controls to assure that the "A" service water pump is not used as a single operable pump. The inspector verified that procedures OP 2264, "Conduct of Outages" and OP 2326A, "Service Water System," were changed in March and July 1996, respectively, to formalize these corrective actions. Operators received training on the new controls through required reading.

The inspector determined that the service water flood protection design requirements had not been correctly translated into specifications and procedures. This is a violation of 10 CFR 50 Appendix B, Criterion III, "Design Control." 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.

E8.4 (Closed) LER 50-336/96-08; Containment Sump Screen Mesh has Holes Larger than Designed.

a. Inspection Scope (92700)

On February 20, 1996, Unit 2 was shutdown due to concerns that small post-accident debris, which passes through the containment sump screens, could clog the small openings in the high pressure safety injection (HPSI) system throttle valves. Subsequent licensee inspection of the sump screens revealed many holes in the screen mesh that exceeded the design mesh size. These concerns were reported to the NRC in LER 50-336/96-08. The inspector reviewed the identified problems and verified the safety consequences and corrective actions.

b. Observations and Findings

The containment sump screens are designed to prevent debris from clogging the containment spray and emergency core cooling systems (ECCSs) during the sump recirculation phase of an accident. Failure to meet this design intent raised a serious potential for common cause failures of these safety systems. Licensee review of an industry operating experience report led them to the fact that the screen mesh size (0.187 in^2) could pass material larger than the throttled opening of the HPSI throttle valves. The industry experience report mitigated the significance of this concern because the low pressure safety injection (LPSI) system provides the primary cooling source in the recirculation mode. Since HPSI is the only system used for the recirculation phase of emergency cooling at Unit 2, the plant was shut down while analysis and corrective

actions were pursued. Licensee analysis subsequently showed that containment sump flow velocities were sufficiently low such that only low density materials could be transported from the screens, up to the pump suction pipe openings. These openings are 11 inches above the containment floor. The licensee concluded that any low density material that reached the suction pipe would be pulverized in the close tolerance safety injection pumps, and/or would be forced through any smaller orifice by high system differential pressure at these points. The inspector was concerned that the suction strainer had an open mesh top. High density material sinking into the water in containment could possibly flow into the suction pipes through the top grating. As described below, the licensee redesigned and fabricated a new sump strainer assembly. The new design incorporated a solid top, thus resolving this NRC concern.

Unit 3 also reassessed the potential for containment sump debris clogging ECCSs during accidents. The licensee's operability determination similarly concluded that only low density material would transport, and it would not prevent fulfillment of the safety function. Initial NRC review of this concern did not identify any immediate safety concerns. However, further licensee review raised questions regarding the need for operator action to compensate for clogging or accelerated erosion due to high flow at these choke points. The issue of low density material smaller than the screen mesh design effecting ECCSs remains **unresolved** pending NRC review of any required operator actions, and confirmation that the harder debris cannot be transported to the pump suction **(URI 336/96-06-10)**.

During the February 1996 Unit 2 shutdown, the licensee inspected and compared the containment sump strainer against the current design specifications. Several discrepancies were identified where debris much larger than the screen mesh size could pass through the strainer. Specifically, the two end panels and the center partition of the strainer were constructed of wire mesh with greater than the designed (0.187 in^2) openings. In addition, there were ten locations where openings as large as 0.25 inch by 2 feet were identified. The cause of the strainer discrepancies was construction/installation error and poor oversight. The strainer was last worked on in January 1988 when the center partition was noted to be missing. However, repair efforts did not assure that the correct screen mesh size was installed at that time, nor did licensee response to this discrepancy identify the other construction/design discrepancies which apparently existed at that time.

Technical Specification 3.5.2, "ECCS Subsystems," and 3.6.2.1, "Containment Spray System," require two operable trains of ECCS and containment spray during plant operation at power. Because the sump strainer would pass debris larger than the system design, the potential to compromise the safety function of both trains of ECCS and containment spray existed. The low density material size would be reduced passing through ECCS pumps and differential pressure at choke points would tend to pass this material through. However, this position did not address the potential for higher density material to reach ECCS components from the top of the strainer and could not confirm the operability of the ECCSs during prior operations with a strainer that would not perform its design function. While the probability of a loss of coolant accident with loss of ECCS function is low, the consequences of that scenario are unacceptable, and must be prevented.

The licensee redesigned the strainer to resolve the discrepancies. These repairs were implemented using the recently improved design control process that provides stronger controls than those in place when the strainer was last modified. Also, the licensee is engaged in a comprehensive verification of the plant design basis, which should identify any other significant system design flaws.

In February 1996, the licensee also reported another potential ECCS analysis discrepancy. Review of the containment sump recirculation design basis had revealed that reactor water storage tank level could decrease faster than the final safety analysis report (FSAR) described scenario. Therefore, it was questioned whether HPSI alone could cool the core at this time, since LPSI shuts down during the sump recirculation mode. The licensee subsequently determined that adequate HPSI cooling exists at the earlier switchover time and retracted the report. The inspector reviewed the licensee's justification and had no further questions regarding the adequacy of sump recirculation timing. The licensee will verify the adequacy of the FSAR description of this function during their ongoing design basis review.

c. Conclusions

10 CFR 50, Appendix B, Criterion XVI requires conditions adverse to quality such as deficiencies to be promptly identified and corrected. The containment sump strainer deficiencies represent a potential common mode failure that could have rendered both ECCS and containment spray inoperable. The licensee's identification of this problem based on the review of recent industry operating experience demonstrated a current conservative approach to safe plant operation. However, the failure to address these issues when other discrepancies were identified in 1988 represents a failure of the licensee's corrective action program. These are **apparent violations** of TSs 3.5.2 and 3.6.2.1, and Criterion XVI. **(EEI 336/96-06-11)**

E8.5 (Closed) LER 50-336/96-13; Potential Common-Mode Failure in Wide Range Nuclear Instruments

This event involved the discovery of a potential susceptibility to common-mode failure within the wide range nuclear instrument (WR-NI) channels. The problem is caused by the presence of one nonsafety-related annunciator circuit that interfaces with all four channels of the WR-NI instrumentation. The annunciator circuit was designed with coil-to-contact, to contactor isolation. However, the WR-NIs experienced cross-channel interference through the common circuit on March 8, 1996, caused by a single power supply malfunction. The inspector noted that the LER did not discuss permanent modifications to resolve the design concerns. Those actions are detailed in NRC Inspection Report 50-336/96-201.

The LER also noted that the original WR-NI reactor protection trip on high rate-of-change in power had been removed in 1978. The licensee subsequently determined that the removal of this reactor trip may not have been consistent with the current methodology for analysis of a rod withdrawal accident. This problem was promptly reported to the NRC on July 17, 1996 and supplemented on August 12, 1996. NRC will review the cause and corrective actions for this issue upon receipt of the followup LER to these telephonic reports.

E8.6 (Closed) LER 50-336/96-19; Electrical Equipment Qualification of Solenoid Operated Valves Inside Containment

a. Inspection Scope

The inspector evaluated the licensee's response to LER 50-336/96-19.

b. Observations and Findings

On March 26, 1996, the licensee discovered that the connectors for seven solenoid operated valves located inside containment did not have the required electrical equipment qualification (EEQ) for operation in a harsh environment. They had previously determined that the connectors for these containment isolation valves were not required to be qualified. This was based on an incorrect assumption that the valves' only safety function was to close and a harsh environment would cause a short resulting in the valves failing closed on a loss of power. During recent efforts to reorganize EEQ databases, the licensee recognized the mis-identified safety functions of these EEQ components. In fact, it is necessary to reenergize these solenoids to open the valves later in the post-accident scenario. The affected components included the containment air radiation monitors, hydrogen monitors, post-accident sampling system, charging supply, pressurizer auxiliary spray line, and hydrogen purge valves.

The LER stated that the root cause of this event was that programmatically, the licensee had not completed an adequate review to define all the safety functions that individual components and circuits must perform and the duration over which they must perform that function. This weakness had been previously identified and in 1993 the licensee created an EEQ Program Manual that formally delineated responsibilities of key groups that provide input into the EEQ program. Safety Integration and Analysis (SI&A) was defined as the responsible group for providing the safety functions and operating durations of EEQ equipment. However, SI&A did not begin their reassessment until 1995, and are not yet completed. In LER 96-19, Unit 2 committed to complete the process of redefining the safety functions of all EEQ components and to disposition identified deficiencies prior to entering Mode 2.

Prior to Mode 4, the licensee committed to correct the seven solenoid valves connectors that were identified and to update the associated EEQ documentation. NRC interviews with the Unit 2 coordinator for the EEQ Program revealed that although there may be EEQ documentation for individual components, there is no EEQ documentation for the circuit as a whole, which includes connectors. The licensee is in the process of preparing the EEQ circuit documentation.

The non-EEQ connectors for four of the seven solenoid valves had previously been discussed at a 1988 enforcement conference (NRC Inspection Report 50-336/88-20). These included the containment isolation valves for the containment air radiation monitors, the hydrogen monitors, the post-accident sampling system, and the hydrogen purge valves. The proposed violation discussed 10 solenoid operated valves that did not did not have EEQ connectors. At the enforcement conference, the licensee provided reasons that they believed that enforcement action was not warranted. The licensee stated that only one of

the 10 valves, an atmospheric dump valve, had terminations that required environmental qualification because this was the only valve that required energization to perform its safety function (i.e., valve opening). The other nine valves, all feedwater or containment isolation valves, were said to go to their safe (i.e., closed) positions when their coils are deenergized. This information was incorrect for the four containment isolation valves because these valves also had a safety-related function to open. As a result, the NRC did not consider the safety consequences associated with the four unqualified solenoid valves when making enforcement decisions. In addition, the inaccurate information prevented implementation of corrective actions to replace the unqualified connectors at that time.

The inspector reviewed the licensee's EEQ program more broadly and found that three elements involved in an effective program have not been adequately completed to date, including: (1) As stated above, the safety function(s) of individual components and the duration they must perform that function has not been comprehensively and accurately defined for EEQ program components; (2) The licensee has determined that the 1986 EEQ field walkdowns were inadequate because the walkdowns were not comprehensive; the walkdowns were performed by maintenance technicians and contractor personnel that were not adequately trained; and many concerns identified in the walkdowns were not adequately dispositioned. As a result, during the current shutdown, the licensee plans to complete a comprehensive walkdown of accessible EEQ equipment; and (3) The licensee determined that EEQ preventive maintenance requirements had not been incorporated into the Unit 2 maintenance tracking system.

Although not applicable to the solenoid operated valves discussed in this LER, the inspector also noted that the licensee has not yet completed their High Energy Line Break (HELB) Program for Unit 2. This project assesses the harsh environment parameters (temperature, pressure, humidity, radiation levels, etc.) for spaces outside containment. In the licensee's "Short Term Review of Final Safety Analysis Report Amendment 23 (HELB effects)," dated August 1, 1990, the licensee stated that, "engineering has been performed and plant modifications installed without regard to impact upon the High Energy Line Break program." The licensee's initial corrective actions included performing a "short term" or "cursory" reevaluation of the 1973 HELB report to look for "obvious programmatic problems." This short-term review identified the need to redefine realistic subcompartment environmental conditions because "it became increasingly apparent that environmental conditions identified in a number of plant areas were inaccurate." In 1990, the licensee discovered that the environmental conditions associated with an auxiliary steam line break were much more severe than the existing design basis break postulated in the main steam system. Walkdowns were performed in areas of the plant that were considered mild environments, but where auxiliary steam piping penetrated, to determine what safety-related equipment could be affected by a postulated auxiliary steam line break. The areas affected were the control room, the control room ventilation room, and the auxiliary building 14' 6" elevation. Discussions with the licensee indicated that although this concern was identified in 1990, the monetary and personnel resources necessary to redefine the environmental conditions have routinely been diverted such that this project has not yet been completed. Similarly, the licensee also has not completed the project to evaluate the dynamic (pipe whip, steam impingement) consequences of a pipe break.

c. Conclusion

10 CFR 50.49 requires that: (1) each item of electric equipment important to safety shall be qualified by testing and/or analysis of identical or similar equipment, and the qualification based on similarity shall include a supporting analysis to show that the equipment to be qualified is acceptable; and (2) a record of the qualification shall be maintained in an auditable form to permit verification that each item of electrical equipment important to safety is qualified and that the equipment meets the specified performance requirements under postulated environmental conditions. The failure to adequately establish the qualification of the connectors for the seven solenoid valves discussed in LER 50-336/96-19 is an **apparent violation (EEI 336/96-06-12).** This is of particular concern because four of the seven valves were the subject of previous escalated enforcement activities in 1988. Due to inadequate licensee reviews, inaccurate information was provided to the NRC regarding the safety function of the valves and therefore, this safety concern was not properly dispositioned.

Programmatically, the failure to accurately define the harsh environment parameters for equipment outside containment and to correctly define the safety functions of all EEQ equipment is a significant concern because this information provides the foundation for qualification of each component. When combined with an incomplete understanding of what is currently installed and its condition, this raises the uncertainty regarding the ability of safety related components to perform their design function(s) in the environment the component or circuit may experience. Although the EEQ Program and HELB Program are within the scope of the 50.54(f) design reviews that are currently underway, significant licensee management focus in this area is needed to support restart of Unit 2. In addition, since the same organization implemented the original EEQ program requirements for all the licensee's nuclear units, it is likely that similar problems may exist at the other units.

Report Details

Summary of Unit 3 Status

Unit 3 remained in cold shutdown throughout the inspection period. The licensee's review to verify compliance with their established design and licensing basis is ongoing.

U3.I Operations

U3.O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations; including control room activities, unit daily status meetings, management review team (MRT) evaluations of adverse condition reports (ACRs), and assessments of operability determinations (ODs) and reportability evaluations for degraded plant conditions. Discussions with licensed plant operators and management personnel revealed good cognizance of the current plant conditions and expected plant problem areas. For example, during the current outage, it was anticipated that both shutdown margin monitors (SMMs) would become inoperable due to the decay of the neutron sources that provide a minimum count rate to keep the SMMs on scale. NRC Inspection Report 50-423/96-05 provides a detailed discussion of this issue, as documented in ACR 12495. On June 21, 1996, the licensee issued a contingency action plan, approved by the plant operations review committee (PORC), for inoperable SMMs. Hence, when the second of the two SMMs went off scale and was declared inoperable on July 25, 1996, the licensee had in place the appropriate action plan to meet the requirements of the technical specification (TS) 3.3.1, action 5(b).

The inspector reviewed the implementation of other compensatory measures; e.g., the issuance of Bypass/Jumper 3-96-076 to address a deficiency documented in ACR M3-96-0568 involving an electrical manhole cover, tornado design restraints. The ODs and reportability evaluations for additional ACRs were also reviewed. The inspector attended a PORC meeting on July 26, 1996, and observed a good questioning attitude by PORC members in evaluating the adequacy of a new project instruction intended for issuance as part of the Unit 3 Configuration Management Plan (CMP). Subsequently, the resident inspectors were apprised of licensee Nuclear Safety and Oversight assessment activities relating to the ongoing engineering reviews involved with the CMP. Overall, the licensee's approach to problem identification and resolution (e.g., ACRs) and process controls (e.g., the CMP) appeared to be receiving an appropriate level of management attention and oversight.

Additionally, using Inspection Procedure 71707, the inspectors observed various routine plant evolutions and normal shutdown operational activities to verify the acceptability of the overall conduct of operations. With respect to operational controls, particularly in consideration of shutdown risk criteria, Unit 3 was found to be operated safely in cold shutdown (mode 5) conditions during this inspection period.

U3.O7 Quality Assurance in Operations

O7.1 Audit of the Quality Assurance Program (40500)

(Open) IFI 50-423/96-06-xx

During the inspection period, the inspector attended the June 28, 1996, Joint Utility Management Assessment (JUMA) team exit. The JUMA audit was to evaluate the effectiveness of the licensee's Quality Assur A) Program. The scope of the audit was to evaluate actions taken to address pre assessments of the QA organization, evaluate philosophy, guidance, and staff understanding for the designation of critical attributes for work activities, review the implementation and effectiveness of the audit and surveillance programs, and to assess the value added as a result of QA activities.

The JUMA team concluded that the audit, surveillance, and inspection programs at Millstone were not effective in the implementation of their Mission Statement and the resolution of identified problems. The team attributed these problems to:

- Lack of support for the QA organization by executive and line management.

- Lack of an effective corrective action program.

Some adverse condition reports were generated as a result of the audit findings. One addressed that there were no requirements to respond to audit findings within 30 days as required by ANSI/ASME N45.2.12, "Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants," and another identified that the Unit 1 Measuring and Test Equipment audit had not been performed within the specified 24 months. The JUMA audit also identified that the designation of critical attributes for work activities was weak.

The inspector concluded that this assessment activity was effective in identifying significant problems in the QA program. At the conclusion of this inspection, the licensee was developing an action plan to address the findings in the JUMA audit. The licensee indicated that the corrective actions would be folded into their Nuclear Excellence Plan. Actions taken to address these concerns are considered an item for further inspection followup and will be addressed in the Restart Assessment Plan.

U3.O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LER 50-423/96-11: Surveillance testing revealed that both trains of the control room envelope pressurization system (CREPS) were inoperable in violation of Technical Specification (TS) 3.7.8. The 36 foot elevation of the control room was unable to achieve the required positive one-eighth inch differential pressure due to an imbalance in the air-conditioning system that serves the control room. The imbalance was determined to have occurred 17 days earlier after modifications were made to the control room. The inspector reviewed the Final Safety Analysis Report and found no detailed description of

the functional relationship between the control room air conditioning and CREPS. Therefore, the adverse impact of the imbalance was not considered until the surveillance testing identified the problem. 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. This LER is closed.

O8.2 (Closed) LER 50-423/96-16: This LER documented a condition outside the design basis of the plant and an inadvertent Engineered Safety Feature actuation. The safety related 4160 volt switchgear cabinet seismic qualification had not been maintained as a result of the bolts on the rear door and the seismic latches on the front door not being used. While engaging the latches to restore the seismic qualification, a relay mounted on the door actuated, resulting in a control building isolation. The inspector examined the switchgear door and latch configuration and discussed the identified concerns with engineering personnel. This LER documented an issue with minor consequence and only hypothetical significance. Corrective action was effected and this LER is closed.

O8.3 (Closed) URI 50-423/96-04-12, Unanalyzed Containment Piping Design; (Closed) LER 50-423/96-07, Containment Recirculation Spray and Quench Spray System Outside Design Basis

a. Inspection Scope (92901)

On April 3, 1996, the licensee determined that the plant had operated in a condition that was outside the design basis due to a deficiency in the design of the recirculation spray system (RSS) piping supports, for which the loading analysis had not appropriately considered accident temperatures. Subsequently, the licensee determined that based upon design basis accident temperatures inside containment, the unacceptable pipe support stress conditions also applied to the quench spray system (QSS). LER 423/96-07 was submitted on May 2, 1996, to document these deficient conditions. Unresolved item (URI 423/96-04-12) was documented during a follow-up NRC inspection to track the licensee's continued engineering analyses and corrective actions. In NRC Inspection Report 50-423/96-05, further review of the design change and modification work packages affecting the RSS pipe supports was documented. During this inspection, the inspector assessed the status of the continuing design reviews, the field work and component modifications, and the overall implementation of corrective measures.

b. Observations and Findings

The inspector reviewed completed work packages and noted that the RSS and QSS modifications have been completed. However, the licensee determined that other systems [i.e., safety injection (SI), both inside and outside containment, and the reactor plant component cooling (CCP)] require similar analysis. The pipe support and structural steel reviews for these other systems resulted in the need for additional pipe support and structural modifications. Installation of these design changes has been ongoing during this inspection period.

The inspector also reviewed several engineering records to assess licensee actions relative to the origin of the RSS design concerns. In 1993, the licensee identified RSS Design Basis Documentation Package (DBDP) discrepancies that led to the documentation of adverse condition report (ACR) 159 in 1995. The licensee's followup of this adverse condition in March, 1996, led to the identification of the current containment temperature concerns wherein post LOCA containment temperatures cause excessive piping system stresses. While the initial review of these concerns was documented with the issuance of ACR 10773, several other ACRs have since been issued. These document related problems with elevated containment temperature effects and single failures that could be postulated to raise the temperature of system fluids beyond that which had been previously analyzed. The inspector confirmed that such issues, and related problem examples, have been considered in the report of the project instruction (PI) 2 team findings, relative to the Unit 3 specific assessment conducted as part of the licensee's Configuration Management Plan.

Notwithstanding the generic reviews and corrective measures implemented by the licensee since the issuance of ACR 10773, LER 423/96-07 documents the fact that the RSS and QSS systems were found to be in noncompliance with design-basis requirements. The licensee's basis for initial reasonable assurance of continued operability for both systems with the plant in mode 4 and heading to cold shutdown (mode 5) conditions suggested that neither the RSS, nor the QSS system could be considered operable under full power operating conditions. This design deficiency, adversely affecting the operational status of systems required to mitigate the consequences of an accident and governed by the unit technical specifications, has existed since the issuance of the initial operating license for unit 3 in 1985. While the licensee has committed to submit a supplement to LER 423/96-07 by September 13, 1996, addressing the generic implications to other plant systems, the inspector noted that the need to modify certain SI and CCP pipe supports has already been established and is in progress.

c. Conclusions

With respect to the design-basis capability of the RSS and QSS system functions, Unit 3 was operated in violation of the Unit 3 technical specifications over a period of several years. Furthermore, since at least 1993, a DBDP deficiency documented concerns in this area, but was not adequately addressed by the licensee's corrective action program until ACR 10773 was initiated in 1996. While the licensee plans to submit an LER supplement to update the generic implications and status of activities related to this problem, the existing facts support the position that past operation of Unit 3 with this design deficiency is an **apparent violation (EEI 423/96-06-13)** of regulatory requirements.

U3.II Maintenance

U3.M1 Conduct of Maintenance

M1.1 General Comments (62707)

On July 31, 1996, the inspector attended the prejob briefing for maintenance activity M3-95-609, loop calibration of containment recirculation pump 3RSS*P1A discharge flow

transmitter. The briefing included discussion of the adequacy of the tagout, potential personnel safety hazards, and the required retest. The supervisor alerted the technicians that the job would require a safety related component being declared inoperable, potentially placing the plant in a technical specification action statement, and that blocking open the access door to the room would affect a plant fire barrier. In addition, the supervisor cautioned the workers to work within the job scope and that the identification of any additional work would require that the work order be revised. The inspector concluded that the brief by the instrument and control supervisor was thorough.

U3.M3 Maintenance Procedures and Documentation

M3.1 Trisodium Phosphate (TSP) Surveillance (61726, 92901)

a. Inspection Scope

Amendment No. 115 to the Unit 3 operating license (OL) NPF-49 was issued on May 26, 1996. This revision, as implemented with plant design change record (PDCR) MP3-94-135, amended the plant technical specifications, reflecting the replacement of sodium hydroxide from the refueling water chemical addition tank (CAT) with TSP as the pH control agent for the containment spray system. The inspector reviewed the licensee's procedures and records relating to the TSP surveillance requirements, examined specific field configurations of the completed PDCR, and assessed the impact of the resulting modifications upon the Unit 3 Final Safety Analysis Report (FSAR).

b. Observations and Findings

The inspector reviewed Surveillance Procedure (SP) 3606.10 for the TSP storage basket volume check, conducted at least once each refueling interval. Since a dodecahydrate form of TSP was utilized in the design, a surveillance based upon a volume check conservatively ensures a sufficient amount of TSP remains available for pH control of the recirculation coolant during an accident. Even if any humidity-induced agglomeration occurs, the density in the TSP baskets would increase; thus, providing for TSP additions to the minimum refill line to effectively increase the mass of TSP available for accident response. The inspector confirmed that the required surveillance was conducted during the last refueling outage in May, 1995, and repeated in April, 1996. Adverse condition report (ACR) 12327 was initiated on April 29,1996, to document the finding of the TSP below the required fill line for all twelve containment baskets. This was not unexpected due to the aforementioned agglomeration phenomenon. Nevertheless, for surveillance purposes, corrective measures to refill all TSP baskets prior to taking the plant into mode 4 were specified.

The inspector also examined the completed hardware modifications and pipe capping activities, accomplished in accordance with automated work order (AWO) M3-95-00941, that isolated the CAT from the refueling water storage tank. The applicable design drawings and work records document the in-place abandonment of the CAT and associated piping and components. Since the completed PDCR did not include the FSAR changes relevant to PDCR MP3-94-135, the inspector requested the FSAR change transmittals associated with this design change for further review.

Coincident with the NRC inspection of the records and FSAR change requests referenced with the PDCR closeout, the licensee identified some discrepancies involved with the incorporation of the PDCR design details and its safety evaluation (SE) into the Unit 3 FSAR. The deficiencies were found as part of the licensee's vertical slice review team (VSRT) effort, conducted in accordance with project instruction (PI) 15, and were documented in Unresolved Item Report (UIR) log number 107. Most notably, the SE assumed a containment leak rate greater than that noted in the current technical specifications and in the OL Amendment No. 115 revisions. Also, the FSAR chapter 15 accident analysis was found by the licensee to have not been reviewed for revision and any impact relating to the TSP basket modification. As of the conclusion of this inspection, the discrepancies identified on UIR log number 107 had been documented in ACR 13788 and were pending final disposition. The inspector confirmed that Unit 3 Operational Readiness Plan Punchlist listed ACR 13788 as an issue requiring resolution prior to the unit startup.

c. Conclusions

The licensee's implementation of PDCR MP3-95-135 for replacement of the CAT with TSP baskets inside containment was appropriately handled as a field modification and properly controlled from operational and surveillance standpoints. However, with regard to the licensing basis of this design change, discrepancies were identified that require further analysis, a revision of the PDCR's documented safety evaluation, and additional changes to the FSAR than were documented as part of the PDCR implementation. These issues are currently being tracked by the licensee as items to be addressed prior to plant heatup to mode 4 conditions.

U3.III Engineering

U3.E1 Conduct of Engineering

E1.1 Potential Clogging of the ECCS Throttle Valves - Update

a. Inspection Scope (37551)

As documented in NRC Inspection Report 50-423/96-01, the licensee conducted an operability determination (OD) to evaluate the concern [reference: Adverse Condition Report (ACR) 8897] that eight throttle valves in the emergency core cooling system (ECCS) have openings smaller in size than the maximum dimension of the ECCS recirculation, fine screen sizes. The potential for clogging the valves, and thus restricting ECCS flow during the recirculation phase of safety injection, was analyzed in consideration of the nature of the postulated debris, the "piggy-back" flow path through multiple pumps, and the increasing differential pressure effects. While the licensee concluded that the affected systems were operable at that time, additional information from other plants and other phenomena (e.g., throttle valve erosion) were still being assessed for adverse system impact.

b. Observations and Findings

The Millstone Unit 3 Final Safety Analysis Report (FSAR) documents plant compliance with the regulatory position of NRC Regulatory Guide (RG) 1.82, regarding the ECCS sump and containment spray design. Such guidance indicates that the recirculation sump screen size openings should be based upon minimum restrictions downstream of the pumps and upon recirculation system requirements. Also, Westinghouse Nuclear Safety Advisory Letter, NSAL-96-001, discusses the identification of a potential problem involving the erosion of the ECCS throttle valves under long term (i.e., post-accident, licensing-basis duration) flow conditions. Also, a Westinghouse letter (NEU-91-611) identifies questions about the adequacy of the runout m- -in for certain types of ECCS pumps.

The licensee intends to ad. .s both the NSAL concerns and the RG 1.82 guidance with system modifications. By installing orifice plates in the affected lines such that the maximum pressure drop would not occur at the throttle valves, erosion problems would be lessened and larger valve openings could accommodate the maximum debris size, as well as pump runout considerations. At the conclusion of this inspection period, the licensee was still working on engineering provisions for the orifice plate installation and re-balanced throttle valve settings. The high pressure safety injection (SIH) and charging system (CHS) pump flow characteristics required further evaluation based upon the net positive suction head (NPSH) boost from the "piggy-back" discharge flow from the recirculation spray system (RSS) pumps.

Subsequently, the licensee determined that a combination of design factors, including the initial throttle valve settings, the "piggy-back" flow path, the RSS discharge pressure boost, and the . . and SIH pump runout margins (i.e., the NEU-91-611 issue), required documentation i. :R M3-96-0524 and reporting to the NRC in accordance with 10 CFR 50.72 and 50.73. The licensee made the initial telephonic notification to the NRC headquarters duty officer on August 30, 1996, and is expected to submit an LER on this issue within the next thirty days.

The inspector reviewed the reportability evaluation for ACR M3-96-0524 and determined that the documented design considerations have relevance to the planned corrective measures and engineering modifications for the throttle valve clogging and erosion concerns. The inspector also reviewed NSAL-96-001 and re-assessed the adequacy of the OD for ACR 8897 in light of the new engineering issues that have been identified. The inspector verified that the Final Safety Analysis Report has documented the specific Unit 3 differences between the plant configuration and either the regulatory guidance (e.g., RG 1.82) or the generic Westinghouse ECCS operational provisions; e.g., the RSS pump direct flow path to the reactor vessel is isolated in favor of the "piggy-back" mode via the CHS and SIH flow paths.

c. Conclusions

The licensee's OD for ACR 8897 remains valid relative to the potential throttle valve clogging concerns; however, consideration of licensing commitments to RG 1.82 and the potential for longer-term valve erosion concerns require a plant modification to install orifice plates in the susceptible ECCS flow lines. A recent licensee analysis identified a

related concern (ACR M3-96-0524) with the potential for runout of the CHS and SIH pumps during the recirculation phase of ECCS operation. This could have resulted in pump cavitation with the loss of CHS and SIH pump functions during the "piggy-back" mode of operation. Since this problem is also related to the initial settings of the ECCS throttle valves, the licensee's design modification will have to consider such pump runout issues in addition to the clogging and valve erosion concerns. Pending the licensee presentation of evidence that the planned design change addresses all identified problems and that the submittal of a licensee event report to the NRC which documents the past deficiencies, this issue is considered an **unresolved item. (URI 50-423/96-06-14)**

U3.E2 Engineering Support of Facilities and Equipment

E2.1 Adverse Condition Report (ACR) Review

a. Inspection Scope (37550 and 40500)

The inspector reviewed selected ACRs to assess the effectiveness of the ACR process. The evaluation included an assessment of the root cause determination and whether appropriate corrective actions were identified and implemented to prevent recurrence of the adverse condition.

b. Observations and Findings

ACR 06092 Reactor Coolant System (RCS) Valve Body-to-Bonnet Leak

On November 9, 1995, a leak was identified coming from the "D" RCS loop accumulator injection check valve at the body-to-bonnet joint. The valve is a Westinghouse ten-inch, swing check valve. In taking immediate corrective action, the licensee entered the applicable technical specification action statement, shut down the plant (reference NRC Inspection Report 50-423/95-42), and generated an ACR to document and disposition the problem. The ACR was categorized as a level "B" due to its consequence (reactor shutdown) and its potential for recurrence. Therefore, a root cause investigation was performed in accordance with nuclear group procedure NGP 3.15, "Root Cause Evaluation Program." The inspector verified that the individual performing the evaluation had attended the required root cause training and that the evaluation was documented in accordance with procedure NGP 3.15 guidance.

The root cause investigation determined that the leak was attributed to a lack of metal to metal contact (gap) on the leaking joint, as a result of the valve being reassembled incorrectly in August, 1993. The licensee inspected each installed Westinghouse check valve for gaps and joint leakage and reviewed the maintenance history records for previous leaks. This review resulted in the identification of eight valves (six and ten-inch Westinghouse swing check valves) that had gasketed joints with questionable reliability. Since disassembly of the these valves would have required placing the plant in mid-loop condition, a plant design change request was instead processed to seal weld the body-to-bonnet joints to ensure reliability of the body to bonnet seal.

As additional corrective action, the licensee plans to revise, by October 15, 1996, procedure MP 3766AH to require that the metal to metal fit of the body to bonnet joint be verified when reassembling the valve. The licensee also is evaluating other options for improving the reliability of the body to bonnet seal to eliminate the need to seal weld the joint after further disassembles.

The inspector verified, by review of work orders, that the modification had been performed for the eight Westinghouse check valves. A review of procedure MP 3766AH revealed that the procedure change had not yet been completed. Action item requests had been generated by the licensee to implement the remaining planned actions. No additional leaks from Westinghouse swing check valves have been reported since November 1995.

ACR 1535 Temperature excursion during spent resin dewatering

This issue was categorized as a level "A" ACR. It documented an event that occurred at Unit 1 on June 22, 1995. During the initial dewatering following the transfer of spent resin from the spent resin tank (SRT) to the cask, the waste water temperature in the cask liner rapidly rose from 90°F to 310°F. The inspector reviewed the licensee's investigation and corrective actions.

The licensee's root cause investigation team was unable to recreate this event or determine its specific cause. The licensee postulated that an exothermic reaction had taken place in the liner, which resulted in the increased temperature. The licensee team made several recommendations to mitigate the effects if a similar event were to recur. The recommendations included: establish and maintain a constant line of communication between the liner operator and the radwaste operator until drying begins, have flush water available to refill the liner if heat-up occurs, use demineralized water for resin transfers, and maintain the SRT full of water while the tank is unattended. These recommendations were shared with the other Millstone units for implementation.

The inspector reviewed the applicable Unit 3 procedures and verified that all but the recommendation involving a constant communication link had been properly proceduralized. The implementing procedure required that a direct means of communication be established, but it did not mandate continuous communications. The licensee indicated that although the guidance did not specifically require constant communications, such a practice has been implemented. The licensee indicated that the procedure would be revised to include this recommendation.

ACR 1148 FSAR Not Updated to Reflect New Site Building

This issue was categorized as a level "B" ACR. It documented that the external flooding analysis presented in the Final Safety Analysis Report (FSAR) and an engineering calculation had not been updated to reflect changes to the site. Four buildings had been added or made permanent to the site between 1986 and 1993, without updating all portions of the FSAR or updating pertinent documentation.

As corrective action, the licensee updated the design basis analysis calculations and the FSAR to reflect as-built conditions. To prevent recurrence, the ACR recommended the

addition of an engineering representative to the site utilization committee and to the Unit 3 plant operations review committee (PORC).

The inspector verified that a FSAR change was processed, that the applicable engineering calculation was performed, and that an engineering representative was assigned as a member to the noted licensee committees. However, the inspector identified that the engineering representative was not present at the site utilization committee meeting convened in June 1996.

The inspector verified that the individual performing the evaluation for this ACR had attended the required root cause training. However, a review of the root cause evaluation revealed that it was not documented in accordance with procedure NGP 3.15 guidance. In addition, the ACR was not reviewed by PORC as specified in the ACR. The licensee generated ACR M3-96-304 to document and resolve these concerns.

The inspector determined that the licensee actions to correct similar types of problems were questionable. There are no requirements that all committee members be present at all meetings, nor are there procedural controls in place to alert licensee personnel of a need to consider the potential for flooding when erecting structures on site. The licensee acknowledged the inspector's concern and planned to perform an additional review of the issue. ACR M3-96-304 was modified to address this concern. The Events Analysis department had not raised these problems during their closeout review of this issue.

The independent safety engineering group performed an evaluation of level "A" and "B" ACRs to determine the effectiveness of corrective actions. The evaluation focused on the timeliness and quality of root cause evaluations, the corrective action plans, and the implementation and tracking of the corrective action plans. This review concluded that the majority of the ACRs under review failed to meet one or more of the licensee's established criteria. Only the immediate corrective action demonstrated an acceptable trend. Furthermore, the inspector noted that an ACR had been previously written against the corrective action program as a result of a Quality Assessment Service audit of level "C" and "D" ACRs (reference NRC Inspection Report 50-423/96-05).

b. <u>Conclusions</u>

The inspector concluded that the quality of the root cause investigations and corrective actions associated with these ACRs was mixed. The root cause investigation for the leaking check valve and the temperature excursion during the dewatering of the cask liner was thorough. However, the corrective actions to address the failure to update the FSAR only corrected the specific concern and would not have necessarily prevented recurrence. The NRC expressed concern that none of the discrepancies had been identified by the Events Analysis department, which has the responsibility to review ACRs for closeout.

The issue of an inadequate corrective action program has been previously discussed in NRC inspection report 50-423/96-04. The NRC has indicated that prior to the startup of any of the Millstone units, the corrective action program must be demonstrated to be effective.

E2.2 Loss of Foreign Material Exclusion (FME) Control

a. Inspection Scope (71750)

On August 8, 1996, while lifting the fuel handling tool from the spent fuel pool (SFP), the bottom of the tool became caught on the lead-in for the transfer canal gate and fell into the SFP. The reactor engineer in charge of the evolution immediately stopped the job, notified the shift manager, and generated an adverse condition report to document the event. The inspector monitored the performance of the licensee's recovery efforts.

b. Observations and Findings

NRC Bulletin 96-01, "Control Rod Insertion Problems," documented a concern regarding control rod binding problems in high burnup fuel at Westinghouse designed plants. As a result of these concerns Millstone Unit 3, under the guidance of the Westinghouse Electric Corporation, was one of several plants chosen to perform fuel testing and inspection of selected fuel bundles in the spent fuel pool. After the completion of the required testing and inspections, the Westinghouse representative was removing the aluminum fuel handling tool when it caught and broke at a welded joint and fell to the bottom of the SFP.

Prior to the recovery efforts for the fuel handling tool, the reactor engineer reviewed the root cause investigation for the Unit 1 SFP event (refer to section U1.M1.1) for lessons learned, developed an action plan, and brief all involved parties. A work order was written for retrieval of the foreign material.

The inspector reviewed the work order and verified that procedure WC-1, "Work Control Process," guidance on recovery from loss of FME control was followed. Prior to retrieving the tool, a camera was lowered into the pool to inspect the piece to determine/verify the extent of the damage and determine the location of the foreign material. Indications revealed that the tool was in two pieces next to the transfer gate. The inspector noted that workers discussed each evolution in detail prior to its execution to ensure all parties had a clear understanding of the actions to be taken and any potential consequences. The workers implemented proper FME controls regarding logging material into and out of the FME controlled area and demonstrated good radiological work practices.

c. Conclusions

The inspector verified procedural compliance with the WC-1 guidance, and concluded that the evolution of removing the foreign material was well planned and coordinated.

U3.E7 Quality Assurance in Engineering Activities

E7.1 Review of Design and Configuration Discrepancies

a. Inspection Scope (92903)

In a letter dated June 20, 1996, the licensee documented the Millstone Unit 3 Discrepancy Review Team (DRT) Report. The report contained design and configuration management deficiencies that were identified during licensee reviews, third party reviews, NRC inspections or that were self disclosing through the occurrence of an event. An updated report was provided to the NRC in a letter dated July 2, 1996. The inspectors reviewed the licensee's prioritization of the deficiencies to ensure that issues deferred for resolution after plant startup would not adversely affect the safe operation of the plant.

b. Observations and Findings

The July 2, 1996, submittal indicated that as of June 25, 1996, there were 1187 design or configuration management issues identified. Of these, the licensee determined that 597 required resolution prior to plant startup. The remainder were scheduled for resolution by either the end of 1996 or the next refueling outage. At the time of the inspection, approximately 440 issues that were scheduled for resolution after plant startup remained open.

The inspectors reviewed the summary description of each deferred item and selected for further evaluation approximately 214 issues that appeared to be the most safety significant. For these items, the inspectors reviewed the source document to obtain additional details of the issues. The source documents included adverse condition reports (ACRs), unresolved item reports (UIRs), open item reports (OIRs) and nonconformance reports (NCRs). As a result of the review of the source documents, additional questions on approximately 120 of the issues were directed to the licensee. During the resolution of the questions raised by the inspectors, the licensee decided to revise the priority of 17 of the issues and include them as issues to be resolved prior to startup. The resolution of these items will generally involve procedure improvements, minor drawing changes, or the generation of design documentation for minor modifications. Several of the issues will also require an additional engineering review to ensure that the affected system operability is not jeopardized.

c. Conclusions

The inspectors concluded that the licensee's characterization of the issues was generally appropriate. Most of the items that were upgraded to startup issues during the inspection were associated with conflicting or missing documentation that would not have been expected to have any significant impact on plant operation. The inspectors' initial assessment was that the issues that require additional engineering review were not likely to result in any safety significant problems. At the completion of this inspection, the licensee evaluation process was continuing. Final assessment of the required work prioritization is dependent upon the completed engineering reviews.

U3.E8 Miscellaneous Engineering Issues

E8.1 (Closed) URI 50-423/96-05-13, Design Modifications for Letdown Heat Exchanger Leak Repair

a. Inspection Scope (92903)

As documented in NRC Inspection Report 50-423/96-05, the licensee was evaluating certain NRC questions raised with respect to the implementation of plant design change record (PDCR) MP3-90-243 for leak repair activities on the letdown heat exchanger. Of most significance was the issue of the ASME Code acceptability of the existing lower flange bolted condition. During this inspection, the inspector reviewed the licensee's responses to the questions on the PDCR package review and additional documentation regarding the code compliance and adequacy of the design control measures associated with this modification.

b. Observations and Findings

The inspector identified that design change notice (DCN) DM3-S-[0068 & 1262]-93, sheet 5, details on the Joseph Oat Corporation fabrication drawing (no. 5659, rev. 7) for the letdown heat exchanger appeared to conflict with ASME Code requirements. The drawing notes indicated that 21 of the existing 28 heat exchanger lower flange studs were to be replaced with new studs manufactured of SA-564, Grade 630, Condition H1025-H1100 material having a minimum yield strength of 140 ksi. The replacement studs were fabricated of the specified material (condition H1100) and arrived on site with certified material test report (CMTR) data demonstrating a representative yield strength greater than 149 ksi. Since PDCR MP3-90-243, Rev. 1, documented an assumption that the 21 new studs have adequate strength to provide the structural integrity of the flanged joint, previously served by 28 studs, the minimum yield strength data provides an engineering value that is key to the adequacy of this design change.

However, the ASME Boiler and Pressure Vessel Code, Section III (1983 edition, summer 1983 addenda), subsection NC, in conjunction with Table I-7.1 of the Section III Appendices, requires that the design allowable stress values for this replacement stud material be based upon a minimum yield strength of 115 ksi. Therefore, despite the CMTR data, the PDCR and its associated DCNs take credit for a stud material yield strength in excess of that allowed by the ASME Code. The licensee documented this discrepancy in adverse condition report (ACR) M3-96-0159. Subsequently, the licensee documented in ACR M3-96-0465, that the PDCR/DCN allowance to use Condition H1025-H1100 material (i.e., heat treated to a temperature between 1025 and 1100 degrees F) was also in error in that the ASME Code, Section III, does not approve use of such stud material heat treated below 1075 degrees F.

Additionally, the inspector noted that nonconformance report (NCR) 389-239, initiated in 1989 to track the letdown heat exchanger leakage and the need for repair, had been closed in 1991. The closure was based, in part, upon a commitment (number 3-89-0137) specifying an injectable leak seal repair activity that was subsequently canceled in 1993 because of changing radiological conditions. The increased area radiation levels raised

ALARA ("as low as reasonably achievable") concerns for personnel that would be involved in the planned repairs. Automated work order (AWO) M3-91-01633 had been issued in conjunction with PDCR MP3-90-243, documenting the belief that NCR 389-239 would track the heat exchanger leakage until closure with the planned gasket repairs. However, the NCR was prematurely closed, based upon a commitment that was not fulfilled.

The premature closure of NCR 389-239 also had ASME Code ramifications in that the NCR references ASME Section XI, IWA-5250(b) requirements to evaluate boric acid corrosion on ferritic steel components. This was accomplished in 1989 for the carbon steel studs in the leaking lower heat exchanger flange. However, after 21 of the 28 studs were replaced with the stainless steel material in 1991, in accordance with PDCR MP3-90-243, there is no evidence of a continuing licensee evaluation of the potential wastage of the seven remaining carbon steel studs. The potential credit for the structural strength of these studs to augment the code allowable stress values in this joint was neither quantified, nor documented. Therefore, the ASME Section XI criteria for boric acid corrosion considerations appear to have also been neglected with the premature closure of the QA tracking mechanism for this continuing leakage, i.e., NCR 389-239.

c. Conclusions

The inspector concluded that the licensee's failure to correctly translate the technical requirements of the ASME Code, relating to the consideration and use of replacement stud material, into the design details of PDCR MP3-90-243 represents an **apparent violation** of 10 CFR 50, Appendix B, Criterion III for Design Control. **(EEI 423/96-06-15)** Furthermore, in closing NCR 389-239 based upon a commitment that itself was closed without implementation of the resulting recommendation, the licensee missed opportunities to continue both to track the heat exchanger leakage via a quality document and to conduct appropriate ASME Section XI (IWA-5250) "Corrective Measures". This lapse may have contributed to the lack of recognition of this issue as a code violation and minimized the technical concerns until raised as a material condition problem by plant personnel in June, 1996.

IV Plant Support

(Common to Unit 1, Unit 2, and Unit 3)

R1 Radiological Protection and Chemistry Controls

R1.1 Refueling Outage Radiological Controls

a. Inspection Scope (83750)

The inspectors reviewed radiological controls implemented during outages, including maintaining occupational radiation exposure as low as is reasonably achievable (ALARA), control of radiological work, and radiological housekeeping. The inspectors made frequent tours of the radiologically controlled areas (RCA), and discussed specific radiological controls with the unit radiation protection supervisors, ALARA coordinators and various radiation protection technicians.

b. Observations and Findings

At all three units, the level of work in the radiologically controlled area was very limited at the time of this inspection. With the exception of the liquid radwaste remediation project, essentially all work at Unit 1 had ceased. At Unit 2, reactor disassembly was required for continuation of work and was tentatively scheduled to commence in mid to late August. At Unit 3, work in the containment dome was essentially completed, awaiting completion of documentation and analysis.

On July 16, 1996, a group of plant personnel working on the refueling floor (108' elevation) at Unit 1 became contaminated while attempting to remove a TriNuclear vacuum system from the spent fuel pool. The work involved removing the four filter cartridges from the vacuum unit, then removing the vacuum unit from the spent fuel pool. While raising the unit from the pool, a wire attached to the bottom of the unit became entangled with several control rod blades stored along the east wall of the spent fuel pool. One of the blades became disengaged from its hook and several other blades were moved out of position. Six workers were contaminated, including one worker who had a small "hot" particle located on his face. The inspector interviewed three of the workers, including the lead health physics technician and two deconners, conducted a tour of the refuel floor and discussed the event with unit and site radiation protection managers. The inspector also reviewed the radiation work permit and associated radiation protection procedures involved in this work.

The inspector's review indicated all workers were decontaminated and whole body counts conducted. No internal contamination was detected. The inspector determined that the licensee performed a conservative skin dose calculation for the individual who sustained a hot particle contamination of the skin of the face. The licensee assigned a shallow skin dose of 2.8 rem to the individual who sustained a hot particle contamination of the face (small area near jaw). (The NRC limit for shallow exposure of the skin is 50 rem in a calendar year.)

With the scope and level of work severely changed, ALARA planning at all three units was very limited. Unit 1 had revised its 1996 ALARA goal to 700 person-rem, but this was before discontinuing work. This budget also had included nine projects where so little documentation and work scope estimates existed that the ALARA projections were considered only accurate to within an order of magnitude. This was considered a reflection of poor work planning. Since the start of the Unit 1 refueling outage (RFO 15) in October 1995, a total of 852 person-rem had been expended, including 501 person-rem in 1995.

For 1996, Unit 2 had revised its ALARA goal upwards to 300 person-rem to account for the additional scope of work. The addition of work scope added an additional 250 person-rem to the original annual goal of 50 person-rem.

Also at Unit 2, an initiative was underway to utilize senior health physics technicians as functional coordinators for critical path evolutions (e.g., reactor disassembly/reassembly, steam generator testing and selected valve work). Although the technicians would not have the authority of outage coordinators, this initiative was a step in establishing

ownership for these critical jobs. These individuals would not have collateral radiation protection duties during their tenure as functional coordinators.

At Unit 3, continuing progress in control and minimization of leaking valves was noted. This included continuing efforts by the health physics department to create and maintain a valve data base, which included information on location, radiological history and maintenance.

c. Conclusions

The Unit 1 spent fuel pool event on July 16, 1996, is currently under review by the NRC (See Section U1.M1.1). The contaminations which resulted from this event had little safety significance, and were properly handled by the unit health physics staff.

Continued actions to address the lack of appropriate work control and work planning were needed to allow for improvement of the ALARA programs. Actions taken at Unit 2 to identify coordinators for critical work evolutions during the outage were considered a step in improving work control.

R2 Status of Radiological Protection and Chemistry Facilities and Equipment

R2.1 Unit Radiologically Controlled Areas

a. Inspection Scope (86750)

The inspector reviewed the status of the Unit 1 liquid radwaste remediation project. The inspector interviewed the project leader and project members, and toured the lower levels of the liquid radwaste facility. The inspector also conducted tours of the radiologically controlled areas (RCAs) at all three units.

b. Observations and Findings

The inspector discussed the status of the Unit 1 liquid radwaste remediation project with the project manager and the radwaste operations supervisor. Since the last inspection of this facility, the licensee completed removal of loose filter media and concentrates from the floors of various cubicles, including the "A" concentrator. Non-destructive examination of the floor drain and waste collector and test tanks had also been completed. No safety significant defects were found in the tanks during this testing. The tanks were also de-scaled and flushed, while the overhead piping runs have been cleaned and painted. Piping requiring repair, replacement or tear-out had been identified. The contents of the filter sludge and clean-up filter sludge tanks had also been removed.

Work remaining to be performed included removal of out-of-service equipment, including the two filter sludge tanks, two evaporators and three concentrates tanks. Additionally, new lighting fixtures were to be installed in the overhead, refurbishment of various pumps and piping runs was to be undertaken, a new filter sludge tank was to installed, and a new processing system (to replace the Ecodex filter) was to be procured. Due to budgetary constraints, the removal of the tanks and vessels has been scheduled for 1997.

c. Conclusions

The licensee continued to make progress in addressing the material and radiological conditions in the Unit 1 liquid radwaste facility. A significant amount of work remains, however, before the remediation project is completed. A significant improvement in radiological and general housekeeping was also noticed in the maintenance area behind the Unit 1 high pressure turbine.

R2.2 NUSCO Thermoluminescent Dosimetry Laboratory

a. Inspection Scope (83750)

The inspector reviewed the licensee's corporate thermoluminescent dosimetry (TLD) laboratory. Included in this review were discussions with the laboratory manager, assessment manager and laboratory staff.

b. Observations and Findings

The Northeast Utilities Service Company (NUSCO) dosimetry laboratory provides personal TLDs to the staff at all three Northeast Utilities nuclear stations (Millstone, Connecticut Yankee and Seabrook). In addition, the facility also provides TLDs for special uses, such as area TLDs at Seabrook Station. Previously, the TLD laboratory was under the direction of the Radiological Assessment Branch (RAB), but has recently been placed under the Millstone RPM. In July, a new laboratory manager was assigned from Millstone, formerly a staff radiological engineer.

The laboratory is preparing for its scheduled biennial audit by the National Voluntary Laboratory Accreditation Program (NVLAP), scheduled for September 1996. During the previous NVLAP audit in 1994, a number of problems were identified, especially in the area of timeliness of corrective actions. The inspector discussed with the laboratory manager and quality assurance manager actions taken to address these concerns. Actions taken included a tracking system for laboratory corrective actions and commitments, and a heightened use of review teams from the stations to evaluate laboratory performance. The inspector reviewed the most recent NVLAP sample analysis from 1995. The laboratory successfully passed all eight evaluation categories, and also passed the new category IX.

The inspector also discussed with laboratory personnel recent concerns with area TLD results from Seabrook Station. The laboratory staff's assessment of the problem identified several concerns, including the laboratory's methodology for maintaining anneal date records and the ability of the laboratory to process and analyze environmental-type TLDs. The inspector discussed with the laboratory manager, Millstone RPM and the Director, General Services these issues and the licensee's plans for laboratory improvement.

c. Conclusions

The NUSCO TLD laboratory continues to provide accurate assessment of the dose of record for radiologically exposed personnel at the three Northeast Utilities nuclear sites. Enhancements in laboratory operations were identified by the licensee as necessary to maintain performance in this area.

R5 Staff Training and Qualification in Radiological Protection & Chemistry

R5.1 Staff Training and Qualification in Radiological Protection & Chemistry

a. Inspection Scope (83750)

The inspector reviewed the qualifications of the interim radiation protection manager, and discussed the health physics technician training programs with members of the technical training staff. The inspector also reviewed new training initiatives involving plant radiological workers.

b. Observations and Findings

Recently, the Radiation Protection Manager (RPM) for Millstone Station resigned his position. The radiological engineering supervisor was immediately named interim RPM. The inspector reviewed the interim RPM's qualifications and determined that the individual met the plant technical specifications at all three units to serve in this position.

The inspector reviewed the continuing training program provided to health physics technicians, through review of course outlines and materials, and interviews with members of the technical training staff. At the time of this inspection, a cycle of training on Connecticut Yankee was being provided to the Millstone Station personnel, to facilitate the loaning out of technicians during outage operations, and to assist during emergencies. The inspector also toured a mock-up training facility being utilized by operations personnel to enhance their performance in a radiological environment.

c. Conclusions

The RPM position has been temporarily filled by a fully qualified health physics professional. The technical training department continues to provide timely, in-depth training and support to the health physics staff.

R8 Miscellaneous Radiological Protection & Chemistry Issues

R8.1 Miscellaneous Radiological & Chemistry Issues

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspector reviewed the applicable portions of the UFSAR that related to the areas inspected. The

inspector verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

P3 EP Procedures and Documentation

P3.1 An in-office review of the Millstone Nuclear Power Station emergency plan revision 21 and implementing procedure EPOP 4475, change 02, "Manager of On-site Resources (MOR)" submitted by the licensee was completed. The inspector concluded that the revisions did not reduce the effectiveness of the E-Plan and were acceptable.

S1 Conduct of Security and Safeguards Activities

S1.1 Unauthorized Entry Into the Protected Area

a. Inspection Scope (81700)

The inspectors reviewed the event associated with an unauthorized entry into the Millstone Station protected area (PA) by an administrative contract person.

b. Observation and Finding

On August 5, 1996, at about 8:00 a.m., an individual working for an administrative contractor arrived at the station to report for a work assignment. The individual had worked at the station, inside the PA until her previous assignment ended on July 19, 1996. Due to an oversight, she did not surrender her badge and key card upon termination (under favorable conditions). However, her key card had been deactivated. The individual assumed that her security badge would allow access to the station for the new assignment.

The individual proceeded to the access control center, rather than the processing center where she was directed to report. She made a telephone call to an individual, already inside the PA, who would be a co-worker and requested to be escorted to her new work area because she was not sure of its location. When the co-worker arrived at the access control center, she saw that the individual was having trouble entering through the access portal and used her own valid key card and hand geometry to allow the individual to enter. The co-worker assumed there was a problem with the turnstile. The co-worker followed the unauthorized individual into the PA by keying in a second time. The two individuals reportedly worked in proximity to each other in the PA for the entire day shift.

When the individual with the deactivated key card attempted to exit the station at the end of the shift at about 3:40 p.m., the deactivated key card caused an alarm to which the security force responded. Upon questioning the individual, the unauthorized access earlier in the day was identified.

Interviews of both individuals and a review of the computer access record by the licensee indicated that neither individual had entered a vital area during the shift. The licensee promptly implemented its procedure for an unauthorized individual in the PA. The licensee

initiated an investigation which is continuing. The licensee does not suspect that any malevolence was intended and disciplinary action for both individuals is pending.

c. Conclusions

During this event, an individual failed to comply with the licensee's requirements and conditions of unescorted access authorization. This issue is **unresolved (URI 245/96-06-16)** pending completion of the licensee's corrective actions and further NRC review.

S8 Miscellaneous Security and Safeguards Issues

S8.1 General

On August 1, 1994, the Commission amended 10 CFR Part 73, "Physical Protection of Plants and Materials," to modify the design basis threat for radiological sabotage to include the use of a land vehicle by adversaries for transporting personnel and their hand-carried equipment to the proximity of vital areas and to include the use of a land vehicle bomb. The amendments require reactor licensees to install vehicle control measures, including vehicle barrier systems (VBSs), to protect against the malevolent use of a land vehicle. Regulatory Guide 5.68 and NUREG/CR-6190 were issued in August 1994 to provide guidance acceptable to the NRC by which the licensees could meet the requirements of the amended regulations.

A February 29, 1996, letter from the licensee to the NRC forwarded Revision 24 to its physical security plan. The letter stated, in part, that vehicle control measures meet or exceed all maximum parameters of design basis threat criterion and specifications found in Regulatory Guide 5.68 and NUREG/CR-6190. A NRC July 3, 1996, letter advised the licensee that the changes submitted had been reviewed and were determined to be consistent with the provisions of 10 CFR 50.54(p) and were acceptable for inclusion in the NRC-approved security plan.

This inspection, conducted on July 22 and 23, 1996, in accordance with NRC Inspection Manual Temporary Instruction 2515/132, "Malevolent Use of Vehicles and Nuclear Power Plants," January 18, 1996, assessed the implementation of the licensee's vehicle control measures, including vehicle barrier systems, to determine if they were commensurate with regulatory requirements and the licensee's physical security plan.

S8.2 Vehicle Barrier System (VBS)

a. Inspection Scope

The inspectors reviewed documentation that described the VBS and physically inspected the as-built VBS to verify it was consistent with the licensee's summary description submitted to the NRC and was in accordance with the provisions of NUREG/CR-6190.

b. Observations and Findings

The inspectors' walkdown of the VBS and review of the VBS summary description disclosed that the as-built VBS was consistent with the summary description and met or exceeded the specifications in NUREG/CR-6190. During the physical inspection of the VBS, the inspectors noted that the VBS in one area was only marginally acceptable. After discussion between the licensee and the inspectors, it was determined that the effectiveness of barrier could be significantly enhanced through a simple modification. The modification was completed at this location prior to the conclusion of the inspection.

c. Conclusion

The inspectors determined that there were no discrepancies in the as-built VBS or the VBS summary description.

S8.3 Bomb Blast Analysis

a. Inspection Scope

The inspectors reviewed the licensee's documentation of the bomb blast analysis and verified actual standoff distances provided by the as-built VBS.

b. Observations and Findings

The inspectors' review of the licensee's documentation of the bomb blast analysis determined that it was consistent with the summary description submitted to the NRC. The inspectors also verified that the actual standoff distances provided by the as-built VBS were consistent with the minimum standoff distances calculated using NUREG/CR-6190. The standoff distances were verified by review of scaled drawings, and actual field measurements.

c. Conclusion

No discrepancies were noted in the documentation of bomb blast analysis or actual standoff distances provided by the as-built VBS.

S8.4 Procedural Controls

a. Inspection Scope

The inspectors reviewed applicable procedures to ensure that they had been revised to include the VBS.

b. Observations and Findings

The inspectors reviewed the licensee's procedures for VBS access control measures, surveillance and compensatory measures. The procedures contained effective controls to provide passage through the VBS, provide adequate surveillance and inspection of the

VBS, and provide adequate compensation for any degradation of the VBS. The inspectors' review of the procedure for compensatory measures disclosed that clarification of certain requirements in the document would make it more user-friendly. Security Procedure SEP 5019, "Compensatory Measures," was revised prior to the completion of the inspection to clarify those portions of the procedure.

The inspectors also reviewed the licensee's Common Operating Procedure C-OP-200, "Respond to Severity Events," Rev. 0, June 10, 1993. This procedure provides guidance for plant operations personnel during a security event and directs the operations personnel into the appropriate Emergency Plan classifications. The inspectors' review of this procedure disclosed that it provided guidance for situations that would include a land vehicle bomb detonation at the VBS.

c. Conclusions

The inspectors' review of the procedures applicable to the VBS disclosed no discrepancies.

V. Management Meetings

X1 Exit Meeting Summary

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

X1.2 Final Safety Analysis Report Review

A recent discovery of a licensee operating their facility in a manner contrary to the updated final safety analysis report (UFSAR) description highlighted the need for additional verification that licensees were complying with UFSAR commitments. All reactor inspections will provide additional attention to UFSAR commitments and their incorporation into plant practices, procedures and parameters.

While performing the inspections which are discussed in this report the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors as documented in Sections U2.O3.1, and U3.M3.1.

Security requirements are not specifically included in the UFSAR; they are in the licensee's NRC-approved security plan. While performing inspections discussed in this report, the inspectors reviewed applicable portions of regulatory requirements that related to the areas inspected. In addition to inspecting the licensee's VBS, the inspectors also reviewed the licensee's Protected Area Barriers (PA). The criteria for PA Barriers are contained in 10 CFR 73.2, 10 CFR 73.55(c)(1) and the licensee's NRC-approved security plan. The inspectors conducted a physical inspection of the PA Barriers (excluding the intake

structures) and determined that all barriers were installed and maintained as required by the security plan and applicable regulatory requirements. No discrepancies were noted.

X3 Management Meeting Summary

XS.3 Drop-in Meeting By NU Managers

a. Inspection Scope (92904)

Mr. T. Harpster and Mr. F. Rothen, representing NU management conducted a drop-in meeting with NRC staff on August 13, 1996, at the Region I office. Accompanying Messrs. Harpster and Rothen were Messrs. K. Gallen and J. Gutierrez, members of the law firm of Morgan, Lewis & Bockius. Representing the NRC were Messrs. J. Wiggins and R. Nimitz of the DRS staff and Mr. J. Durr of DRP. The topic covered during the meeting involved NU presenting the results of the investigation performed by Mr. Gallen related to the Millstone, Unit 1 radwaste facility.

b. Observations and Findings

The licensee's investigation concluded the following:

1. No indication or substantive evidence suggest any NU individual intentionally provided inaccurate communications to NRC.

2. There were instances of miscommunications; a number of individuals that discussed conditions with NRC inspectors had no first-hand current information. The individuals had no actual knowledge of current status and based their answer on dated information.

3. No NU employee saw a connection with the Nine Mile Point 1 experience; NMP1 had floating barrels which didn't exist at Millstone.

4. NU employees believed that NRC knew of conditions in the MSP1 tank rooms. That limited the scope of discussions in their answers to NRC questions.

5. NU employees thought that going into a room compromised ALARA principles; the need to conserve dose was more important because management expectations were to reduce collective exposures so that MSP1 would lead the BWR fleet.

6. NU employees used an "answer the question" attitude and thus did not volunteer extra information that might have been related to the topic of the question.

7. No entries were made in the blocked-off tank rooms from about 1990 to November 1994. An entry was made into one room in reaction to indications of a leak. That November 1994 entry confirmed the existence of the leak plus material on the floor. A PIR and NCR were issued; final corrective action was

deferred. Meanwhile, personnel changes occurred along with procedure changes.

8. The PIR issued in November 1994 was closed after the planning for the modification was completed; not the implementation of the modification.

9. Problems existed in management accountability and the articulation and enforcement of management expectations.

10. NU committed to put their investigation report on the docket. If that report contains privacy issues, NU will submit a full and a redacted report with the necessary affidavit to claim the basis for withholding the full report.

c. Conclusions

1. The licensee's review uncovered no evidence of NU staff intentionally misleading the NRC.

2. NU staff tended to answer NRC questions very narrowly and they also did not have first-hand, current information when they addressed NRC questions.

3. Significant problems with management accountability and managem ᐧt expectations adversely affected the radwaste systems issues. Simil problems existed in other areas.

4. Radwaste problems were identified in PIRs; the PIRs were closed based on a plan of attack being developed and not corrective action implementation.

Other reports have addressed NRC assessment of the technical, performance, management and enforcement issues.

INSPECTION PROCEDURES USED

IP 37550: Engineering

IP 37551: Onsite Engineering

IP 40500: Licensee Self-Assessments Related to Safety Issues Inspections

IP 61726: Surveillance Observations

IP 62703: Maintenance Observations

IP 62707: Maintenance Observations

IP 71707: Plant Operations

IP 71750: Plant Support Activities

IP 81700: Physical Security Program for Power Reactors

IP 83750: Occupational Radiation Exposure

IP 86750: Solid Radioactive Waste Management and Transportation of Radioactive Materials

IP 92700: Onsite follow-up of Written reports of Nonroutine Events at Power Reactor Facilities

IP 92901: Follow-up Operations

IP 92903: Follow-up Engineering

IP 93702: Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED AND CLOSED

OPEN

URI 245/96-06-01	U1.O1.3 Drywell fire
URI 245/96-06-02	U1.M1.1 Spent fuel pool filter removal
URI 245/96-06-03	U1.M1.2 Inservice inspection program
EEI 245/96-06-04	U1.E8.1 Nonconformance Reports
EEI 336/96-06-05	U2.O3.1 Boric acid sampling
URI 336/96-06-06	U2.M8.2 EDG overload during surveillance
URI 336/96-06-07	U2.E1.2 Refueling pool drain line
URI 336/96-06-08	U2.E8.1 Shutdown cooling system water hammer
URI 336/96-06-09	U2.E8.2 Core thermal power exceeded
URI 336/96-06-10	U2.E8.4 Containment sump screen mesh size
EEI 336/96-06-11	U2.E8.4 Failure to identify containment sump screen mesh size
EEI 336/96-06-12	U2.E8.6 EEQ of solenoid valve electrical connectors
EEI 423/96-06-13	U2.O8.3 QSS/RSS piping outside the design basis
URI 423/96-06-14	U3.E1.1 ECCS throttle valves potential clogging
EEI 423/96-06-15	U3.E8.1 Letdown heat exchanger stud material yield stress
URI 423/96-06-16	U3.S1.1 Unauthorized entry into the protected area

CLOSED

URI 245/96-05-07	U1.E8.1 Nonconformance Reports
LER 336/96-01	U2.O8.1 RCS Heatup rate
LER 336/96-02	U2.O8.2 Service water strainer backwash
LER 336/96-03	"
LER 336/96-04	"
LER 336/96-05	"
LER 336/96-07	U2.O8.3 RCS Cooldown rate
LER 336/95-40	U2.M8.1 RPS Surveillance
LER 336/95-41	U2.M8.2 EDG Overload during surveillance
LER 336/95-42	U2.M8.3 Offsite electrical alignment
LER 336/95-44	U2.M8.4 Containment personnel airlock
LER 336/95-45	U2.M8.5 Charging system valve leak
LER 336/96-12	U2.M8.6 Missing valve internals
LER 336/95-19	U2.E8.1 Failed snubbers on SDC
LER 336/95-43	U2.E8.2 Core thermal power limit exceeded
LER 336/96-06	U2.E8.3 Flooding of service water pumps
LER 336/96-08	U2.E8.4 Containment sump screen mesh size
LER 336/96-13	U2.E8.5 Wide range nuclear instruments
LER 336/96-19	U2.E8.6 EEQ of solenoid operated valves
LER 423/96-11	U3.O8.1 Control room envelope pressurization
LER 423/96-16	U3.O8.2 4160V switchgear cabinet seismic qualification
LER 423/96-07	U3.O8.3 QSS/RSS piping outside the design basis
URI 423/96-04-12	U3.O8.3 QSS/RSS piping outside the design basis
URI 423/96-05-13	U3.E8.1 Letdown heat exchanger leakage

LIST OF ACRONYMS USED

ACR	adverse condition report
ALARA	as low as reasonably achievable
ANSI/ANS	American National Standards Institute/American Nuclear Society
AOP	abnormal operating procedure
ASME	American Society of Mechanical Engineers
AWO	automated work order
BAST	boric acid storage tank
BWR	boiling water reactor
CCP	reactor plant component cooling
CEA	control element assembly
CFR	Code of Federal Regulations
CHS	charging system
CMP	Configuration Management Plan
CMTR	certified material test report
CREPS	control room envelope pressurization system
DBDP	Design Basis Documentation Package
DCN	design change notice
DRP	Division of Reactor Projects
DRT	Discrepancy Review Team
EA	escalated enforcement
ECCS	emergency core cooling system
ECP	estimated critical rod position
EDG	emergency diesel generator
EEI	escalated enforcement item
EEQ	electrical equipment qualification
EPOP	emergency plan operating procedures
ERT	event review team
FME	foreign material exclusion
FSAR	Final Safety Analysis Report
GDC	general design criterion/criteria
GL	Generic Letter
gpm	gallons per minute
HELB	high energy line break
HFP	hot full power
HPSI	high pressure safety injection
HZP	hot zero power
IFI	inspector follow item
IGSCC	intergranular stress-corrosion cracking
IP	inspection procedure
ISI	inservice inspection
IST	in-service testing
JUMA	Joint Utility Management Assessment
LCO	limiting condition for operation
LER	licensee event report
LNP	loss of normal power

LOCA	loss of coolant accident
LPSI	low pressure safety injection
MOR	Manager of On-site Resources
MRT	management review team
MTF	master tracking form
MTU	metric ton uranium
MWD	megawatt days
NCR	nonconformance report
NFE	Nuclear Fuels Engineering
NFS	nuclear fuel section
NGP	Nuclear Group Procedure
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NRI	no recordable indications
NSAL	Nuclear Safety Advisory Letter
NSIC	Nuclear Safety Information Center
NUREG	Nuclear Regulation
NUSCO	Northeast Utilities Service Company
NVLAP	National Voluntary Laboratory Accreditation Program
OD	operability determination
OIR	open item report
OL	operating license
PDCR	plant design change record
PDR	Public Document Room
PIR	plant information report
PORC	plant operation review committee
QA	quality assurance
QAS	Quality and Assessment Services
QSS	quench spray system
RAB	Radiological Assessment Branch
RCA	radiologically controlled area
RCP	reactor coolant pump
RCS	reactor coolant system
RFO	refueling outage
RG	Regulatory Guide
RSS	recirculation spray system
RWST	refueling water storage tank
SBGT	standby gas treatment
SDC	shutdown cooling system
SFP	spent fuel pool
SI	safety injection
SI&A	Safety Integration and Analysis
SIH	high pressure safety injection
SMM	shutdown margin monitors
SRT	spent resin tank
TLD	thermo-luminescent dosimeter
TS	technical specifications
UFSAR	updated final safety analysis report

UIR	unresolved indication report
URIs	unresolved items
VBS	vehicle barrier system
VSRT	vertical slice review team
WR-NI	wide range nuclear instrument