U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.: 50-245/90-12

Docket No.: 50-245

License No. DPR-21

Licensee: Northeast Nuclear Energy Compar·
P.O. Box 270
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Facility Name: Millstone Nuclear Power Station, Unit 1

Inspection at: Waterford, Connecticut

Dates: June 26, 1990 through August 6, 1990

Reporting
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Inspection Summary: Report 50-245/90-12

Areas Inspected: Routine NRC resident inspection of plant operations, radiological controls, maintenance/surveillance, security, engineering/technical support and safety assessment/quality verification.

Results: See Executive Summary

Executive Summary

Plant Operations

No noteworthy findings were identified in this area. One unresolved item regarding performance of primary system boundary leakage surveillance requirements was closed.

Radiological Controls

Reviews in this area did not identify any noteworthy findings.

Security

Reviews in this area did not identify any noteworthy findings.

Surveillance and Maintenance

Corrective maintenance activities regarding recirculation pump seal replacement and emergency diesel generator voltage regulator repairs were well performed. Performance strengths in this area were demonstrated by incorporation of lessons learned into maintenance procedures and restoration of diesel generator operability within the technical specification limiting condition for operation action period. One unresolved item regarding posting of safe heavy load paths on the refueling floor of the reactor building was closed. A weakness identified during a 1989 NRC maintenance team inspection concerning definition of work order retest requirements was also closed.

Engineering and Technical Support

One unresolved item regarding house heating steamline break effects on environmental qualification mild environments was closed. Two unresolved items were opened concerning resolution of weaknesses identified during a licensee review of a 1973 high energy line break study, and seismic mounting of safety-related electrical equipment. Timely restoration to operable status of the emergency diesel generator and resolution of seismic concerns regarding the voltage regulator cabinet were indicative of licensee performance strength in this area.

Safety Assessment/Quality Verification

Licensee response to NRC Generic Letter 88-14, Instrument Air Supply Problems Affecting Safety-Related Equipment, was reviewed with respect to drywell nitrogen system quality and its affect on the operability of the automatic pressure relief system. No inadequacies were identified.

Two licensee-identified violations of NRC requirements were identified regarding environmental qualification of electrical equipment and failure to perform a surveillance within the periodicity required by technical specifications. These violations were not cited since the criteria of 10 CFR 2, Appendix C, Section V.G.I were met.

One licensee-identified violation regarding failure to perform a surveillance test as required by plant technical specifications was cited since corrective action for a previous identical violation was ineffective.

In general, the licensee demonstrated a good regard for safe plant operation through the scope of its corrective actions concerning events reported to the NRC pursuant to 10 CFR 50.73.

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* The NRC inspection manual inspection procedure (IP) or temporary instruction (TI) that was used as inspection guidance is listed for each applicable report section.

DETAILS

1.0 Persons Contacted

Within this report period, interviews and discussions were conducted with members of Northeast Nuclear Energy Company (NNECo or the licensee) management and staff as necessary to support inspection activity.

2.0 Summary of Facility Activities

At the start of the inspection period, Millstone Nuclear Power Station Unit 1 (Millstone 1 or the plant) was in cold shutdown for replacement of the "A" reactor recirculation pump seal. Reactor startup commenced on June 30, 1990, and operation at 100% of rated power was achieved on July 1. With the exception of brief reductions in power to support routine surveillance testing of main steam system components, the plant remained at full rated power for the balance of the inspection period.

A detailed chronology of plant events occurring during the inspection period is included in Attachment I.

NRC Activities

The resident inspection activities during this report period included 131.5 hours of inspection during normal working hours. In addition, routine review of plant operations was conducted during periods of backshifts (evening shifts) and deep backshifts (weekends, holidays, and midnight shifts). Inspection coverage was provided for 18 hours during backshifts and six hours during deep backshifts.

A Region I specialist inspection of engineering and technical support was conducted on July 9-13, 1990. Results of the inspection are documented in Region I combined inspection report 50-245/90-11; 50-336/90-12; 50-423/90-09.

A Region I specialist inspection of radiological controls was conducted on July 23-27, 1990. Results of the inspection are documented in Region I combined inspection report 50-245/90-14; 50-336/90-15; 50-423/90-13.

A Region I specialist inspection in the area of transportation of radioactive waste material was conducted on July 30 - August 3, 1990. Results of the inspection are documented in Region I combined inspection report 50-245/90-14; 50-336/90-16; 50-423/90-15.

3.0 Plant Operations

3.1 Control Room Observations

Control room instruments were observed for correlation between channels, proper functioning, and conformance with technical specifications. Using indicators at the main control board, reactor, electrical, and safety system lineups were verified to be aligned properly. Alarm conditions in effect and alarms received in the control room were discussed with operators. The inspector periodically reviewed the night order log, tagout log, plant incident report log, key log, and bypass jumper log. Each of the respective logs was discussed with operation department staff. One anomaly was observed regarding position indication for low pressure coolant injection system valve 1-LP-12A. This is documented in section 5.2.1 of this inspection report. No other inadequacies were identified.

3.2 Plant Tours

The inspector observed plant operations during regular and backshift tours of the following areas:

Control Room	Reactor Building
Main Battery Room	Diesel Generator Room
Gas Turbine Building	Intake Structure
Turbine Building	Cable Vault

During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication and equipment status. No significant observations were made.

3.3 (Closed) Unresolved Item 50-245/89-08-03, Primary System Boundary Leakage Technical Specification Limits

This item involved a missed reactor coolant system boundary leakage surveillance which occurred during the 1989 refueling outage. Technical specification (TS) 4.6.D requires daily computation of reactor coolant system boundary leakage into the drywell whenever irradiated fuel is in the reactor pressure vessel. If leakage exceeds the limits of TS 3.6.D, the reactor must be placed in a cold shutdown condition within 24 hours. In April 1989, the licensee suspended the surveillance during cold shutdown in order to minimize radiation exposure to workers in the drywell by maintaining the drywell sumps full. Technically, reactor mode is determined by the position of the mode switch on the main control board. Thus, a literal interpretation of the TS would require that the surveillance be performed when the mode switch is placed in the refuel position.

The inspector discussed the TS requirement with licensee engineering personnel. Based on the leak-before-break concept, the limit is based on the ability to detect and measure a leak and assure a low probability of crack propagation. Since propagation of a crack is not credible when the reactor coolant system is less than 200 degrees F and vented, the position of the mode switch does not affect the basis of the TS. Thus, the licensee concluded that the intent of the TS had not been violated and that the problem was administrative in nature.

On April 17, 1989, the licensee issued change 1 to SP-635.1, Reactor Coolant System Leakage Check, to clarify the procedure by waiving the surveillance requirement when the reactor coolant system is less than 200 degrees F and vented with the mode switch in the cold shutdown or refuel positions. TS change request 1-5-89 was initiated to clarify the requirements of the TS. The inspector reviewed these corrective actions and emphasized to the licensee the need for timely submittal of TS changes prior to modifying procedures in such a way that compliance with TS requirements may not be assured. The inspector had no further questions. This item is closed.

3.4 Review of Plant Incident Reports

Millstone 1 plant incident reports (PIRs) were reviewed during the inspection period to (i) determine the significance of the events; (ii) review licensee evaluation of the events; (iii) verify that the licensee's response and corrective actions were adequate; and (iv) verify that the licensee reported the events in accordance with applicable requirements.

The following PIRs warranted inspector followup and are discussed in the inspection report sections cited below:

1-90-52, Exceeding Technical Specification 3.11.A.2
(Section 7.4.5)
1-90-56, "A" Recirculation Pump Seal Failure
(Section 5.1.1)
1-90-58, 1-LP-12A Remote Valve Position Indication
(Section 5.2.1)
1-90-60, Diesel Generator Trip and Lockout
(Section 5.1.2)

3.5 Security

Selected aspects of site security were verified to be proper during inspection tours, including site access controls, personnel searches, personnel monitoring, placement of physical barriers, compensatory measures, guard force staffing, and response to alarms and degraded conditions. No significant observations were made.

4.0 Radiological Controls

4.1 Posting and Control of Radiological Areas

During plant tours, posting of contaminated, high airborne radiation, and high radiation areas was reviewed with respect to boundary identification, locking requirements, and appropriate control points.

No significant observations were made.

5.0 Maintenance/Surveillance

5.1 Observation of Maintenance Activities

The inspector observed and reviewed selected portions of preventive and corrective maintenance to verify compliance with regulations, use of administrative and maintenance procedures, compliance with codes and standards, QA/QC involvement, use of bypass jumpers and safety tags, personnel protection, and equipment aligrment and retest. The following automated work orders were included:

-- M1-90-05632, Sample instrument nitrogen header for generic letter 88-14
-- M1-90-06339, Test new diesel generator components and generator exciter
-- M1-90-06218, Investigate diesel generator trip during synchronization
-- M1-90-06223, Install new isolation and saturable transformers
-- M1-90-05786, Replace "A" recirculation pump mechanical seal
-- M1-90-05861, Replace "A" recirculation pump mechanical seal
-- M1-90-05863, Disassemble and inspect mechanical seal for failure analysis
-- M1-90-04093, Replace "A" recirculation pump mechanical seal
-- M1-90-01962, Install and test check and isolation valves in air line to feed pump minimum flow valves
-- M1-89-12420, Install new coils in HVS-6 per PDCE 1-90-010
-- M1-90-04662, Install new coils in HVS-6 per PDCE 1-90-010
-- M1-90-04663, Install bypass and globe valve in steam line to HVS-6 per PDCE 1-90-010
-- M1-90-06317, Install additional mounting supports on diesel generator governor controls cabinet

No significant observations were made.

5.1.1 "A" Recirculation Pump Seal Replacements

Between June 19 - 26, 1990, the licensee replaced the mechanical seal on the "A" recirculation pump on three occasions. These activities were documented previously in Region I inspection report 50-245/90-09, section 3.4. The seal failures were characterized by broken titanium carbide rotating face rings and stationary face carbons. Vendor representatives were present at the site during the maintenance period to support licensee troubleshooting and repair efforts.

In order to verify proper assembly of the seal, the licensee performed dimension checks of seal cartridge axial movement. The most critical dimensions are upward axial lift and downward axial movement of the seal assembly. The licensee determined that these dimensions, in tolerance individually, were not within an acceptable band collectively. Measurements were then taken to determine the upward lift of the pump when running. A gap of 0.049 inches was found to exist between the pump auxiliary impeller and the bottom of the seal. The vendor representative stated that the minimum acceptable clearance was 0.060 inches to allow for growth of the auxiliary impeller on pump startup and tolerances in the assembly of the impeller in relation to the seal. When the pump is started, it thrusts upward approximately 0.165 inches. If adequate clearance is not assured, the seal will be compressed resulting in cracking of the stationary carbons and rotating carbide face rings.

The licensee is reviewing the seal replacement evolution to identify the reasons why problems were encountered during this normally routine activity. Vendor information regarding seal tolerances and dimension checks has been available to the licensee historically. However, the licensee indicated that several years ago a vendor representative had advised that the dimension checks were not required. This appeared to be supported by previous licensee experience.

As a result of these findings, the licensee performed adjustments to the pump to ensure that the appropriate clearances were obtained. Changes were made to maintenance procedures MP-741.3, Recirculation Pump Seal Assembly Rebuild, and MP-741-4, Recirculation Pump Seal Assembly Removal and Installation, to require independently verified dimension checks of the seal assembly. In order to aid operators in diagnosing potential seal failure during pump operation, a special process computer log was developed to record seal temperatures. A rapid (greater than 20 degrees F per hour) increase in controlled seal bleedoff temperature could indicate imminent seal failure. The replaced pump seal has operated satisfactorily since plant startup on June 30.

The inspector considered that licensee review of this event was an appropriate initiative and that the corrective actions were adequate. The inspector had no further questions concerning this matter.

5.1.2 Emergency Diesel Generator Voltage Regulator Failure

On July 10, 1990, following minor maintenance on the emergency diesel generator (DG), the licensee attempted to perform routine surveillance procedure SP-668.1, Diesel Generator Operational Readiness Demonstration, pursuant to technical specification (TS) 4.9.A.1.a., Emergency Power Sources. The test runs the DG at the full load output of 2665 - 2700 kilowatts for one hour. At 9:18 a.m. the DG started, came up to speed, and exhibited normal electrical parameters. However, two attempts by operators to parallel the machine to its normal bus failed. Approximately 20 seconds after the second attempt, the DG tripped on a generator ground fault. An equipment operator in the DG room simultaneously heard a loud noise and saw heavy smoke coming from the voltage regulator cabinet. The licensee declared the DG inoperable and entered TS limiting condition for operation 3.5.F.2, Minimum Core and Containment Cooling System Availability, which limits continued reactor power operation to the succeeding seven days. The licensee documented the event in plant incident report 1-90-60, Emergency Diesel Generator Trip and Lockout, dated July 10.

The licensee immediately commenced an investigation to determine the cause of the failure. Review of alarm and relay status indicators showed that the DG tripped on high bus-to-ground and/or high bus differential current faults. Visual inspection of the voltage regulator cabinet revealed severe damage to a step-down transformer and its wiring, and other blackened components. Tests performed in accordance with procedure T-90-1-6, DG Voltage Regulator Component Test, resulted in questionable data for two of three field excitation transformers and a linear reactor. No damage to the DG stator, field windings or cables was discovered.

The licensee was unable to locate exact replacement parts for the damaged components. Since no spares were immediately available from the original voltage regulator manufacturer or from other utilities, the licensee issued a purchase order to manufacture the required components. On July 12, a manufacturer field representative arrived on the site to assist in diagnostic testing of the regulator components. The two field excitation transformers were determined to require replacement.

The licensee briefed the NRC staff shortly after the event and started discussions regarding a temporary waiver of compliance from TS 3.5.F.2 in order to permit reactor power operation for an additional three days while replacement components were manufactured, installed, and tested. The NRC staff considered this deviation to be acceptable based on the licensee showing that a design basis accident could be mitigated successfully without the DG and its safety-related loads with no significant increase in accident consequences previously analyzed and accepted by the NRC. The licensee provided additional assurance that the gas turbine generator, the other Unit 1 emergency power source, was operable by successfully completing the surveillance test pursuant to TS 4.9.A.2.a. A temporary waiver of compliance was granted by the staff at 4:55 p.m. on July 16. That evening, the replacement parts were received, installed, and the DG satisfactorily tested. At 5:15 a.m., July 17, the DG was declared operable and the TS limiting condition for operation was exited prior to expiration of the seven-day period.

The inspector discussed the regulator failure with licensee maintenance and production test engineers. Review of plant process computer alarm printouts, graphs of key DG parameters, and component test results did not reveal conclusive evidence regarding the failure mechanism. The data did demonstrate that the voltage regulator had experienced a phase-to-ground fault. The inspector also discussed post-manufacture and post-installation test results with the vendor representative and concluded that the regulator and DG had been tested adequately. The inspector noted that the voltage regulator, by design, had no internal fuse protection which might have limited damage to the unit. Finally, the inspector observed portions of licensee repair activities and noted that quality assurance personnel were present. No inadequacies were observed by the inspector.

During repairs to the DG voltage regulator cabinet, the licensee identified that the existing mounting configuration may not satisfy seismic safety factor requirements. This issue is documented in section 6.2 of this inspection report.

Based on document review, field observations, and discussions with licensee personnel, the inspector considered that the DG was returned to service properly and had no further questions.

5.1.3 (Closed) Unresolved Item 50-245/89-08-07, Control of Maintenance Procedure Revision

This item involved the adequacy of licensee controls to assure that step 5.7.2.2 of maintenance procedure MP 790.4, Control of Heavy Loads, is implemented. The step required that safe load paths be posted on the 108-foot (refueling) level of the reactor building and in the intake structure. In April 1989, during reactor pressure vessel head removal, the inspector noted that the procedure posted on the refueling floor was not up to date.

The inspector discussed this item with the maintenance manager who indicated that the posted procedure had been added to the procedure change distribution list. However, on July 5, 1990, the licensee issued change 5 to MP-790.4, revision 4, which deleted the posting requirement. Consistent with past practice, heavy load lifts are controlled by an automated work order package which includes a verified copy of the procedure. Thus the posted procedure was superfluous. The inspector considered that licensee controls are adequate to assure that lifting of heavy loads is controlled adequately by approved and up-to-date procedures. This item is closed.

5.1.4 Followup of Maintenance Team Inspection Report Items (50-245/89-80)

Inspection report 50-245/89-80 was forwarded to the licensee by letter dated September 1, 1989. The staff's letter requested the licensee to notify the NRC in writing of actions taken or planned in order to enhance maintenance activities regarding the weaknesses identified in Appendix 3 of the report. The licensee responded to the weaknesses by letter dated November 8, 1989. This inspection reviewed licensee corrective action for one of the items. The item number corresponds to that in the report's summary of weaknesses.

6. "Work order procedure is weak in defining requirements for retests and acceptance criteria."

Based on the corrective action being taken pursuant to Revision 21 of ACP-QA-2.02C, Work Orders, and the existing guidance available regarding retests, the concern regarding this weakness is closed.

5.2 Observation of Surveillance Activities

Through observation and data review of surveillance tests the inspector assessed licensee performance in accordance with approved procedures and technical specification limiting conditions for operation, removal and restoration of equipment and review and resolution of deficiencies. The following tests were reviewed:

-- SP 623.18, Emergency Systems Valve Position Check, Revision 2
-- SP 668.1, Diesel Generator Operational Readiness Demonstration, Revision 15
-- SP 622.7, LPCI System Operability Test, Revision 16
-- SP 623.19, Emergency Service Water System Operational Readiness Test, Revision 6

No significant observations were made.

5.2.1 Low Pressure Coolant Injection System Valve Position Indication

On July 2, during performance of weekly surveillance test SP-623.18, Emergency Systems Valve Position Check, the licensee discovered that valve 1-LP-12A indicated an intermediate position on the main control board. The manually-operated isolation valve is on the discharge side of the low pressure coolant injection system "A" loop and is located in the drywell. The valve is locked open and inaccessible during normal plant operation.

The licensee initiated a review of equipment tagout records and questioned all personnel who had had access to the drywell during the recent recirculation pump seal maintenance outage and determined that the valve had not been operated recently. Plant incident report 1-90-58 was initiated to document the event, and automated work order M1-90-06166 was initiated to troubleshoot the position indicator when the drywell next becomes accessible. The licensee discussed its findings with the inspector, who concluded that there was reasonable assurance that the valve was in the required position, and that the problem was most likely with the valve position indication limit switch. The inspector considered the licensee's response to be appropriate and had no further questions.

6.0 Engineering/Technical Support

6.1 (Closed) Unresolved Item 50-245/90-07-02, House Heating Steamline Break Concerns

In May 1990, the licensee identified that certain postulated house heating steam system pipe breaks could result in degradation of areas of the plant previously considered to be environmental qualification (EQ) mild environments. A 1973 high energy line break (HELB) study conducted by the licensee architect-engineer failed to identify this vulnerability. In order to assure that no other potential weaknesses were missed, the licensee performed a review of the study. The review consisted of validation of the shutdown methods credited in 1973, identification of equipment and components required to support the shutdown methods, system walkdowns, and design reviews. While no gross omissions were identified, the licensee developed further concerns regarding the 1973 study which will require long term resolution.

6.1.1 Shutdown Method Concerns:

The licensee found that the four shutdown methods credited in the 1973 study were unacceptable in part, as described below:

-- Use of the isolation condenser did not consider that the control rod drive system would be required to recover and maintain reactor pressure vessel level after a pipe break. The ability to initiate this method of cooling could require local operation of condensate return valve 1-IC-3. In some scenarios, this may not be possible. Finally, since condensate makeup valve 1-IC-10 and the control rod drive pumps are not environmentally qualified, they may not be available for certain breaks in the reactor building.

-- Use of the normal shutdown method (main condenser as a heat sink) cannot be credited for a loss of normal power event. Further, the method relies on equipment and components which may not be protected from a HELB.

-- The control rod drive system, in conjunction with the automatic pressure relief system, was credited with the ability to cool the reactor. However, the control rod drive system does not inject enough water to provide adequate core cooling. Also, this method did not consider the need to cool the torus.

-- Use of the low pressure coolant injection and core spray systems in conjunction with the automatic pressure relief system, was assumed in the study. However, no consideration was given to the ability to cool the torus.

In spite of these weaknesses, the licensee has determined that in all cases, assuming the most limiting single active failure, at least one success path exists consistent with unit emergency operating procedures.

6.1.2 <u>Other concerns identified</u>

The licensee identified other concerns, as listed below:

-- The licensee determined that certain areas of the plant, currently considered EQ mild environments, may be degraded by accidents not previously analyzed. For example, a walkdown of the feed regulating valve enclosure revealed that the room is not leak tight, as previously assumed. Further, no programmatic access controls exist regarding ventilation system ducts and plenums which are relied upon to maintain the integrity of the mild environments.

-- The 1973 analysis did not reflect the full range of possible break sizes or consider small leaks which may not be immediately detectable or of sufficient magnitude to cause automatic isolation of the break. New pressure and temperature profiles may need to be developed to assure the operability of equipment important to safety located in these areas.

-- The 1973 study was not maintained as a living document. Consequently, plant modifications installed since that time may have adversely affected the results of the study. Previously analyzed break locations, based on pipe stress levels, may have changed. For example, the drywell instrument nitrogen system was found to be vulnerable to certain feed system line breaks. (This item is addressed in section 7.1 of this inspection report)

6.1.3 House heating steam system modification

In order to assure that the Unit 1 switchgear and ventilation rooms are protected from the effects of a house heating steamline break, the licensee is implementing a plant design change which either removes, reroutes, or encapsulates portions of the system. Steam heating coils in three air handling units are being replaced by electric heaters, and the switchgear ventilation system modified to provide a winter recirculation heating mode. The licensee expects to complete the modifications by mid-October 1990. The inspector reviewed the planned modifications and concluded that the affected safety systems will be adequately protected.

6.1.4 Final safety analysis report updates

As documented in Region I inspection report 50-245/90-09, section 7.1, sections of the Millstone 1 updated final safety analysis report do not reflect accurately the as-built condition of the switchgear area ventilation system and certain environmental enclosures. The inspector discussed this issue with the licensee who committed to revise the report as necessary.

6.1.5 Conclusion

Based on review of licensee findings and discussions with licensee personnel, the inspector concluded that adequate means are available to assure safe shutdown of the plant in the event of a HELB. The inspector considered that resolution of the weaknesses identified by the licensee as a result of its review of the 1973 study should be prioritized and tracked to completion on a formal basis. The licensee's followup items to be considered include:

-- Review the affects, if any, of plant modifications on pipe break locations previously analyzed.

-- Revise area pressure and temperature profiles as necessary to assure environmental qualification of equipment required to achieve a safe shutdown condition. This should reflect a full range of pipe breaks.

-- Perform calculations necessary to confirm the engineering judgement that the torus can be cooled with the equipment assumed to be available for shutdown methods involving the use of safety relief valves.

-- Provide assurance that operators will be guided to the appropriate emergency operating procedures in the event of a HELB in the turbine building.

-- Address the specific vulnerabilities regarding protection of EQ mild environments identified in the new study.

-- Establish procedures which identify and control boundaries between EQ harsh and mild environments.

This is an unresolved item. (50-245/90-12-01).

Licensee response to the house heating steamline break concern was comprehensive and indicative of licensee performance strength in this area. The inspector will continue to follow this and related EQ issues during the course of future routine inspections. This item is closed.

6.2 Seismic Qualification of Diesel Generator Voltage Regulator Cabinet

Because the replacement step-down transformer was heavier and required mounting higher in the cabinet than the original component, the licensee performed a seismic evaluation of the installation and the cabinet. The cabinet is mounted to its concrete base with shell-type anchor bolts. NRC bulletin 79-02, Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts, dated March 8, 1979, is also used by the licensee as guidance for seismic mounting of safety-related electrical cabinets. The bulletin specifies that shell-type anchor bolt designs provide a seismic safety factor of five.

In order to satisfy this requirement, the licensee searched its files relating to Systematic Evaluation Program (SEP) Topic III-6, Seismic Design Considerations, and could find no calculations regarding voltage regulator cabinet mounting. The licensee then performed calculation GC-137-634-GD and demonstrated that the existing configuration provided a safety factor of 2.5. The inspector agreed with the licensee's conclusion, based on this result, that the cabinet would have remained operable during a safe shutdown earthquake event.

In response to its finding, the licensee installed additional supports pursuant to PDCR MP-1-90-086, D/G Governor Cabinet Modifications, dated July 13, 1990. This modification upgraded the existing configuration to meet the required safety factor. Concerned that this finding might indicate a programmatic deficiency, the licensee also initiated a program to review the adequacy of previous SEP Topic III-6 submittals and the as-built condition of Unit 1 safety-related electrical components.

The inspector concluded that licensee response to the issue of adequate seismic support of electrical equipment was prudent, and demonstrated a good regard for safe operation of the facility. This item remains unresolved pending inspector review of the results of the licensee's programmatic review (50-245/90-12-02).

7.0 Safety Assessment/Quality Verification

7.1 Licensee Response to Generic Letter 88-14, Instrument Air Supply Problems Affecting Safety-Related Equipment

7.1.1. Background

This generic letter, issued on August 8, 1988, requested the holders of operating licenses for nuclear power reactors to perform design and operational reviews of instrument air systems in order to verify that air quality is consistent with manufacturer recommendatio[illegible] components served, and to ensure that safety-related equipme[illegible] function as intended on loss of actuating air during design basis events.

In a letter to the NRC staff dated May 4, 1990, the licensee provided the results of its air quality testing of the containment nitrogen compressor system. Samples were obtained from a drain line in the drywell inerting nitrogen supply header downstream of the compressor three-micron afterfilters. Since this tested only approximately 20 feet of stainless steel piping in the reactor building, the unit engineering staff did not consider the results to be representative of actual conditions at the components in the drywell.

As a result of these concerns, the licensee performed additional nitrogen system quality testing during the recirculation pump seal replacement outage in June 1990, and reported the results to the NRC staff in a letter dated July 20, 1990. The licensee considered these [illegible] results unrepresentative of actual conditions in t[illegible] due to the fact that the samples were obtained after a [illegible]-hour system blowdown rather than "as-found," the samples had not been obtained using a formal procedure, and that four part[illegible]es greater than 1000 microns in size had been counted in one [illegible] the s[illegible] analyzed. However, the licensee concluded, bas[illegible]mance and the results of surveillance t[illegible] 1989 refueling outage, that the safety-relat[illegible]d by the drywell nitrogen instrument he[illegible]le and would remain functional until the next [illegible] outage scheduled for early 1991.

7.1.2 System Description:

The drywell nitrogen compressor system is designed to provide clean, dry nitrogen to the drywell instrument header, which in turn serves, in part [illegible] six main steam safety relief valves (SRV). The nominal operating pressure of the system is 110 psig. The drywell distribution header is carbon steel and was seismically qualified in 1987. The dewpoint of the system is low (-40 degrees F) in order to minimize corrosion in the piping. Two compressors are backed up by a secondary nitrogen supply system consisting of two banks of nitrogen bottles sized to supply a minimum of four hours of actuating air to the safety and main steam isolation valves.

The automatic pressure relief system uses four of the six SRVs to provide a backup to the high pressure emergency core cooling system. In the event of a small break loss of coolant accident, the valves will open to rapidly reduce reactor pressure to within the discharge pressure of the core spray and low pressure coolant injection systems. An actuation signal opens a solenoid-operated valve to admit nitrogen to the SRV pilot which opens the valve. Accompanying each SRV is an accumulator sized for five actuations. If header pressure is lost, the accumulators are isolated from the system by redundant check valves.

7.1.3 Sampling Procedure and Results:

The inspector reviewed licensee data submitted in its July 20 letter and discussed the test methodology and results with the engineer involved in the sampling. The test was performed under automated work order M1-90-05632. The nitrogen header in the drywell was blown down through a cloth at 15 standard cubic feet per minute (SCFM) for 24 hours. Only slight discoloration of the cloth was observed at the end of the blowdown. This result indicated that no particles approximately 1000 microns or greater were present in the line. Four samples were then taken at the inlet to the "F" SRV at 1.0 SCFM; three for 10 minutes, and one for 30 minutes. The samples were collected on Gilman type A/E glass filters held in an aluminum fitting. All components of the sampling rig had been cleaned with freon to ensure that no contamination was present. Measures were employed to minimize the possibility of contamination of the samples during handling at the site.

Fifty cubic feet of nitrogen was sampled through the filters, and 64,689 particles counted. Most of the particles were between 1 - 5 microns in size. Except for four particles greater than 1000 microns collected in the first sample, no particles greater than 20 microns were observed. The critical size to ensure proper operation of the SRV solenoid valves and header check valves is 40 microns and 250 microns, respectively.

7.1.4 Maintenance and Surveillance History:

The inspector reviewed maintenance and surveillance test records for the SRVs and nitrogen system check valves for the last 5 years. Surveillance procedure SP-1091, SRV Nitrogen Air Supply Check Valve Leakage Test, consists of a one-hour drop test of the check valves to ensure seat tightness. The test was performed with satisfactory results in July 1987 and during the recent recirculation pump seal replacement outage. Procedure SP-1097, Manual Operation of Relief Valves ISI Readiness Test, is performed on the SRVs at reduced reactor pressure every 18 months as required by technical specifications. No SRV has failed to operate on demand since April 1981, and no failures to operate due to contamination of the air supply have occurred. The SRV solenoid valves are qualified for five years of service in the drywell environment and are periodically rebuilt when the SRV topworks are routinely replaced.

7.1.5 Conclusions:

The SRVs are located several levels above the nitrogen distribution header in the drywell. Normally there is no flow of nitrogen in the system. The small volume of nitrogen required to actuate the SRVs makes it unlikely that particles in the header would be transported to the solenoid valves and cause the SRVs to malfunction. Based on the results of the samples collected by the licensee, the inspector considered that there was reasonable assurance that the SRVs will remain capable of performing their intended safety function until the 1991 refueling outage, when the licensee plans to install filters in the SRV nitrogen lines.

Since the nitrogen supply header was seismically qualified in 1987, the license discontinued periodic testing of the nitrogen accumulator check valves. However, the licensee recently determined that other failure mechanisms exist which could render both the nitrogen compressors and the backup bottles inoperable. In light of this, the inspector concluded that the licensee should consider performing the test on a regularly scheduled basis.

The inspector had no further questions. Future inspections will review licensee activities in this area.

7.2 10 CFR Part 21 Report; Defective Electrical Lugs

On August 2, the inspector was notified about the potential for use of defective parts at nuclear facilities. The matter was reported to the NRC as a potential generic safety issue, filed as a 10 CFR Part 21 report by another licensed facility. The issue involved the identification of defective 4/0 electrical lugs used in 600 VAC applications. It is believed that the cast copper lugs were cooled too quickly during manufacture, which resulted in an excessively large grain. When the lugs are crimped onto electrical cable, large deep cracks form which can result in failure of the electrical connection. The lugs were procured as commercial grade items and qualified for plant use by the licensee of the other facility. The lugs were purchased in 1989 from the Graybar Company and distributed by Thomas and Betts Company to the other facility.

The inspector discussed this issue with the superintendent - station services at Millstone on August 2. The licensee was requested to review the matter for applicability at Millstone Station, and to inform the inspector of the results of its evaluation. The licensee stated that the issue would be reviewed and corrective actions taken if the potentially defective parts were identified at Millstone.

The licensee's preliminary review, reported to the inspector on August 3, noted that lugs for use on large diameter wire (including the size noted above) were not purchased from Graybar Company. Thus, the matter did not appear to be an issue at Millstone. The licensee does use Graybar lugs in smaller sizes - 16/0 and 18/0. Licensee reviews were in progress at the end of the inspection period to determine whether the smaller Graybar lugs were of concern also.

The inspector had no further comments at the present time. Licensee actions in this matter will be reviewed during future routine inspections.

7.3 Environmental Qualification of Reactor Pressure Vessel Level Instruments

On June 6, 1990, the licensee notified the inspector that the wide range reactor pressure vessel (RPV) Yarway level instruments were not environmentally qualified. The licensee identified this condition during its evaluation of equipment necessary to accomplish safe shutdown of the plant. The instruments are utilized to guide operator response to accidents pursuant to the emergency operating procedures (EOPs). Accidents in which the wide range instruments may be required include loss of coolant accidents in the drywell and high energy line breaks outside of the containment. In accordance with its administrative procedures, the licensee immediately initiated an evaluation of equipment operability and reportability to the NRC staff.

10 CFR 50.49 (b)(3), Environmental Qualification of Electrical Equipment Important to Safety, requires that measures be taken to ensure that certain post-accident monitoring equipment remain functional under accident and post-accident environmental conditions. Regulatory Guide 1.97, Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs During and Following an Accident, revision 2, is referenced by part 50.49(b)(3) as guidance for identification and qualification of instrumentation. The licensee reported its conformance to these guidelines to the NRC staff in an integrated safety assessment program (ISAP) submittal dated October 25, 1985. RPV level was identified as a Type A, Category 1 variable requiring environmental qualification. The submittal stated that since the level instruments were mounted on racks located within enclosures, they did not require qualification. In fact, the wide range Yarways are mounted on instrument racks 2251 and 2252 in the reactor building which are not enclosed.

The level instruments, LITS-263-73A and -73B, are Yarway model 4418EC transmitters which provide indication of RPV level locally at the instrument racks and remotely in the control room. Their range is -340 to +60 inches, instrument zero being the bottom of the steam separator lower skirt. (Indicated level at the top of active fuel is -127.5 inches.) In addition to indication, the instruments form part of the low pressure coolant injection (LPCI) system initiation and control logic for the containment cooling system. In order to reduce post-accident pressure and/or temperature in the drywell, LPCI system flow can be manually aligned to the drywell or torus spray headers provided that RPV level, as sensed by the Yarways, is greater than two-thirds core height. Thus, the interlock minimizes the potential for inadvertently diverting cooling flow from the RPV before recovery of core water level. The interlock is included in technical specification table 3.2.2, Instrumentation that Initiates Emergency Core Cooling Systems.

The inspector reviewed the licensee operability evaluation for the Yarways, including qualification test records for associated cables and terminal blocks and concluded that, though not environmentally qualified, the instruments would remain operable under postulated accident conditions of temperature, pressure, radiation, and humidity. The inspector also noted that a non-redundant, but fully qualified fuel zone level instrument, LI-263-112A, was available to operators on the main control board. The licensee has developed plans to replace the Yarways with fully qualified instruments during the next refueling outage in 1991.

The inspector concluded that there is reasonable assurance of adequate RPV level monitoring capability during and after design basis accidents at Millstone 1. In addition, Updated Final Safety Analysis Report, Section 6.2.2, containment heat removal, shows that the full spectrum of design basis accidents can be mitigated successfully in the absence of drywell spray. Thus, the consequences of failing to provide EQ Yarways have low safety significance. Nonetheless, failure to provide environmentally qualified instruments, or to take measures adequate to protect non-qualified instruments from a harsh environment, is a violation of the requirements of 10 CFR 50.49. This licensee-identified violation is not being cited because the criteria specified in section V.G.1 of 10 CFR Part 2, Appendix C, Enforcement Policy (1990), were satisfied (50-245/90-12-03).

7.4 Licensee Event Reports

Licensee event reports (LERs) were reviewed to assess accuracy, adequacy of licensee corrective actions, and compliance with 10 CFR 50.73 reporting requirements, and to determine whether there were generic implications or if further information was required. The following LERs were reviewed:

7.4.1 LER 90-004, Improper Head Correction/RPS-ECCS Instrumentation

As a result of a program to verify all reactor protection and emergency core cooling system trip setpoints, the licensee determined that the existing head correction for the reactor high pressure scram setpoint was non-conservative. A review of instrument calibration data showed that the current setpoint was acceptable regarding technical specification (TS) requirements. Licensee review of past data revealed one instance, in July 1979, when, due to instrument drift, the TS requirements were not met.

The high reactor pressure scram function is a backup to the reactor high flux scram, the primary protection for design basis events. Unless accompanied by significant instrument drift, the small error involved is not significant.

The licensee has initiated setpoint change request 1-90-21 to correct the error. The root cause of the event, lack of independent verification of setpoint calculations, has been corrected by licensee administrative procedures. The inspector noted no inadequacies regarding licensee corrective actions and compliance with 10 CFR 50.73 reporting requirements.

7.4.2 LER 90-005, Daily Surveillance Greater Than Six Hours From Previous

On April 11, 1990, the licensee reported to the NRC pursuant to 10 CFR 50.73(a)(2)(i)(B) a condition prohibited by the plant technical specifications (TS) which occurred when control room operators failed to ensure that the daily check of the main steam line flow instruments was performed as required by TS table 4.2.1, Protective Instrumentation.

The root cause of the event was a deficiency in the operations department logs which scheduled the surveillance on the basis of an eight-hour shift. Also, at the time of the event, control room operators were distracted by high wind and sea conditions at the site. The surveillance was performed satisfactorily one hour later than required. The licensee has revised the operations log to preclude recurrence of the event.

Failure to perform the instrument check within the time period required by TS table 4.2.1 is a violation. However, this violation of low safety significance is not being cited because the criteria specified in section V.G.1 of 10 CFR 20, Part 2, Appendix C, Enforcement Policy, were satisfied (50-245/90-12-04).

7.4.3 LER 90-006, Failure to Perform Monthly Gas Turbine Fire Protection Surveillance

On April 24, 1990, the licensee determined that technical specification (TS) 4.12.E.2, which requires that non-supervised fire detection circuits be tested every 31 days, had not been met for the gas turbine generator (GT) enclosure fire detection system. The licensee reported this condition pursuant to 10 CFR 50.73 (a)(2)(i)(B), any operation or condition prohibited by plant technical specifications. The operability of the GT was not affected by this condition.

The licensee documented a similar failure to perform this TS surveillance in LER 87-035, Missed Surveillance on Fire Detection System, dated September 18, 1987. This LER reported the licensee's discovery during its fire protection systems audit that six non-supervised circuits had not been tested every 31 days as required by TS. The circuits involved were those in the cable vault, hydrogen seal oil unit, condenser bay, standby diesel generator room, standby diesel generator fuel oil day tank room, and gas turbine generator enclosure. The proposed corrective action included development of procedures to ensure compliance with the TS, and initiation of a change to delete the GT fire detection circuit from the TS.

The six fire detection systems which deviated from the requirements of 10 CFR 50, Appendix R, Fire Protection Program for Nuclear Power Facilities, were documented as unresolved item 50-245/87-19-01 in NRC specialist inspection report 50-245/87-19, dated September 23, 1987. The inspection team concluded that these deviations did not affect adversely the systems necessary to achieve and maintain safe shutdown conditions following a fire. This conclusion was reaffirmed during a Region I specialist inspection of the licensee fire protection program performed in May 1989, (Inspection report 50-245/89-10, section 2.0).

In its response letter to the NRC dated December 8, 1987, the licensee committed to initiate procedure changes and minor system modifications to the affected fire detection systems by December 1988. Systems requiring major modifications were added to the licensee integrated safety assessment program (ISAP) for evaluation as topic 1.101, Fire Detection System Code Compliance. As a result of its evaluation, the licensee assigned a low priority to these modifications. This conclusion was reported to the NRC in a letter dated November 9, 1988, and was periodically confirmed by ISAP submittals to the NRC dated September 29, 1989, and April 30, 1990. Thus the licensee had ample opportunity to correct the condition reported in this LER.

The inspector reviewed completed surveillance records for procedures SP-418H, Gas Turbine Fire Detection Functional Test, and SP-422H, Fire Detection Non-Supervised Lines Functional Test, and noted that with the exception of the GT fire detection system, the circuits had been tested on a monthly basis as required by TS 4.12.E.2. The licensee has changed its surveillance tracking system to ensure that SP-418H is also performed every 31 days. Also, as discussed above, a TS change request has been initiated to delete the GT test from the TS.

Although the inspector concluded that this licensee-identified item is of low safety significance, this violation of a TS surveillance requirement is being cited since licensee corrective action for a previously identified violation was ineffective (50-245/90-12-05). The inspector had no further questions regarding this LER.

7.4.4 <u>LER 90-007, Gas Turbine LCO Determined to be Exceeded</u>

Previous NRC review of the adequacy of corrective actions regarding this LER was documented in Region I inspection reports 50-245/90-07, section 8.1.1 and 50-245/90-09, section 8.2. No inadequacies were noted regarding licensee compliance with 10 CFR 50.73 reporting requirements.

7.4.5 <u>LER 90-008, Exceeding Technical Specification 3.11.A.2 - APLHGR Limit</u>

On May 31, 1990, with the reactor at 80% of rated power, the licensee performed a routine control rod pattern adjustment which significantly increased the axial bottom peak power of the core. Approximately one hour after returning to full power operation, the licensee determined that the average planar linear heat generation rate (APLHGR) thermal limit had been exceeded. The licensee immediately inserted control rods and reduced the operating APLHGR to an acceptable value, which met the requirements of the technical specification (TS) limiting condition for operation. This LER was submitted pursuant to 10 CFR 50.73(a)(2)(i)(B), operation prohibited by plant technical specifications, and TS 3.11.D, which requires an event report if fuel assembly thermal limits are exceeded.

The cause of the event was underestimation by the reactor engineer of the xenon transient which occurred after restoration of full power operation. Licensee corrective actions included scheduling of additional training for reactor engineers and the development of an engineering department instruction to provide guidelines for monitoring core conditions during reactor power changes. The inspector concluded that these actions adequately addressed the cause of the event and had no further questions.

7.4.6 LER 90-009, House Heating Steam High Energy Line Break

This event was reported pursuant to 10 CFR 50.73(a)(2)(v), which requires reporting of any condition that alone could have prevented the fulfillment of safety-related functions needed to shutdown the reactor and maintain it in a safe condition, and to remove core residual heat. Inspector review of licensee activities regarding its identification of the house heating steam system as a high energy line break item is documented in section 6.1 of this inspection report. No NRC reporting requirement inadequacies concerning this event were identified by the inspector.

7.4.7 LER 90-010, EEQ Barriers Violated

Previous inspector review of the corrective actions and generic implications concerning this LER are documented in Region I inspection report 50-245/90-09, section 8.1. No inadequacies were noted regarding licensee compliance with 10 CFR 50.73 reporting requirements.

7.5 Periodic Reports

Upon receipt, periodic reports submitted pursuant to technical specifications were reviewed. This review verified that the reported information was valid and included the required NRC data. The inspector also ascertained whether any reported information should be classified as an abnormal occurrence. The following report was reviewed:

-- Monthly Operating Report - June 1990

8.0 Management Meetings

Periodic meetings were held with station management to discuss inspection findings during the inspection period. A summary of findings was also discussed at the conclusion of the inspection. No proprietary information was covered within the scope of the inspection. No written material was given to the licensee during the inspection period.

Attachment I

Millstone Unit 1 Status

June 26 Plant heatup in progress with reactor power at 20% on intermediate range 9. Heatup secured and reactor shutdown commenced at 1:43 a.m. due to failure of "A" reactor recirculation pump seal. Reactor was shutdown at 5:40 a.m. and plant in cold shutdown at 11:05 a.m.

June 30 Commenced reactor startup after recirculation pump seal replacement at 2:17 a.m. Reactor critical at 3:25 a.m. Main generator synchronized to the grid at 3:10 p.m.

July 1 Reactor at 100% of rated power at 12:00 p.m.

July 10 At 9:27 a.m. the emergency diesel generator was declared inoperable and the seven-day limiting condition for operation action statement of technical specification 3.5.F.2, Minimum Core and Containment Cooling Systems Availability, was entered due to a fire in the voltage regulator cabinet.

July 12 Reactor power reduced to 80% for turbine stop valve and bypass valve surveillance testing. Full power operation restored at 4:30 a.m.

July 16 A temporary waiver of compliance granting a three-day extension to the emergency diesel generator technical specification was granted by NRC Region I staff at 4:55 p.m.

July 17 Repairs to the emergency diesel generator were completed at 3:00 a.m. Surveillance testing was completed satisfactorily at 5:06 a.m. Diesel generator was declared operable and technical specification limiting condition for operation exited at 5:15 a.m.

August 2 At 4:00 a.m., reactor power was reduced to 80% for testing of turbine stop, intercept, and bypass valves. Full power operation was restored at 5:20 a.m.