U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No. 50-423

License No. NPF-49

Licensee: Northeast Nuclear Energy Company
P.O. Box 270
Hartford, CT 06101-0270

Facility: Millstone Nuclear Power Station, Unit 3

Location: Waterford, Connecticut

Dates August 29 through October 15, 1989

Inspectors: W.J. Raymond, Millstone Senior Resident Inspector
K.S. Kolaczyk, Resident Inspector, Millstone 3

Approved by: [signature] 12/15/89
D. R. Haverkamp, Chief Date
Reactor Projects Section 4A
Division of Reactor Projects

Inspection Summary: Inspection on August 29 - October 15, 1989 (Inspection Report 50-423/89-16)

Areas Inspected: Routine onsite inspection at Millstone 3 during normal and backshift work periods of plant operations; maintenance and surveillance; security; engineering and technical support; and safety assessment and quality verification activities.

Results: Overall, plant operations were conducted safely during the report period. Good performance was noted in response to a security incident outlined in Section 6.1 and in self assessment activities as noted in Section 7.0. An unresolved item was opened on the failure of the licensee to enter the appropriate action statement when MSIV testing revealed that a solenoid valve was in a degraded condition as noted in Section 4.2.4. Additionally, an apparent deviation was identified for failure to perform independent full functional testing of both trains of MSIV safety systems. This concern is outlined in Section 4.2.5. A weak area was identified in the licensed operator requalification program as outlined in Section 3.2. Four licensee-identified non-cited violations concerned: (1) Failure to enter a containment building technical specification action statement outlined in Section 3.4. (2) Failure to declare a fire house inoperable as outlined in Section 3.5. (3) Improper posting of fire watches as outlined in Section 4.2.1. (4) Inadequate testing of a radiation monitor outlined in Section 4.2.2. One NRC-identified non-cited violation concerned technician use of an out-of-date procedure as described in Section 4.2.3.

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*The NRC Inspection Manual Inspection Procedure or temporary instruction that was used as inspection guidance is listed for each applicable report section.

DETAILS

1.0 Persons Contacted

Inspection findings were discussed periodically with the supervisory and management personnel identified below:

*S. Sudigala, Senior Engineer
*J. Barile, Engineer
*M. Hess, Senior Engineer
P. Callaghan, Manager, Nuclear Safety Engineering
S. Scace, Station Superintendent
*C. Clement, Unit Superintendent, Unit 3
*M. Gentry, Operations Supervisor
R. Rothgeb, Maintenance Supervisor
*J. Harris, Engineering Supervisor
D. McDaniel, Reactor Engineer
R. Satchatello, Health Physics Supervisor
M. Pearson, Operations Assistant
R. Place, Supervisor, Nuclear Safety Engineering
*B. Enoch, Supervisor, Instrumentation and Controls

*Denotes those attending exit meeting.

2.0 Summary of Facility Activities

The plant operated at 100% of rated power during most of the report period. Minor power reductions were required on September 2, 8, and 22 to perform condenser backwashing operations. Intake system problems such as seaweed clogged traveling screens on September 23 and a disabled screen wash system on October 2 raised the possibility of a reactor trip due to a loss of condenser vacuum. The licensee displayed good operating practice during both of these events by reducing power below the P-9 "turbine trip reactor trip setpoint." These rapid 50% power reductions went smoothly and showed that the licensee is sensitive to intake system problems.

Problems identified in the operator requalification program by Region based inspectors were quickly addressed by the licensee. The effectiveness of the immediate actions were evaluated by the NRC and no additional concerns were identified. The effectiveness of the long-term corrective actions will be evaluated by the NRC in future inspections.

3.0 Plant Operations (IP 71707/71710/93702)

3.1 Control Room Observations

The inspector reviewed plant operations from the control room and reviewed the operational status of plant safety systems to verify safe operation of the plant in accordance with the requirements of the technical specifications and plant operating procedures. Actions taken to meet technical specification requirements when equipment was inoperable were reviewed to verify the limiting conditions for operations were met. Plant logs and control room indicators were reviewed to identify changes in plant operational status since the last review and to verify that changes in the status of plant equipment was properly communicated in the logs and records. Control room instruments were observed for correlation between channels, proper functioning and conformance with technical specifications. Alarm conditions in effect were reviewed with control room operators to verify proper response to off-normal conditions and to verify operators were knowledgeable of plant status. Operators were found to be cognizant of control room indications and plant status during normal working hours and 54 hours of backshift observation. Control room manning and shift staffing were reviewed and compared to technical specification requirements. No safety concerns were noted.

On several occasions during the report period the operators displayed particularly good performance. As a result of intake screen fouling that was caused by seaweed from Hurricane Hugo during the night of September 22, 1989, the operators were required to make a 50% power reduction in 45 minutes. This was necessary to prevent a reactor trip due to loss of condenser vacuum. Additionally, while an I&C technician was performing troubleshooting activities on a feedwater regulating valve, the valve went completely shut. Prompt operator action was taken to restore steam generator level on the affected generator and prevent a reactor trip. The significant downpower maneuver with no adverse plant performance and the quick action taken to restore steam generator level showed good crew performance.

3.2 Requalification Training Program Weaknesses

During the week of September 18, 1989, NRC examiners administered requalification exams to twelve Millstone Unit 3 operators. This was the first NRC administered requalification exam at Unit 3 since the commencement of commercial operation in April of 1986. The specific examination results are contained in inspection report 50-423/89-09. Preliminary results from grading the job performance measures (JPM) and simulator portions of the exam were presented to the licensee on September 22, 1989. These results revealed that of the twelve individuals that were examined, six failed various portions of the simulator and JPM portions of the exam. Additionally, of the three crews that were examined, two failed - one crew was an operating watch standing crew, the other was a crew that does not normally stand watch. These results differed with the licensee's evaluation which concluded that four operators had failed the job performance examinations and one of the operating crews had failed the simulator exam.

NUREG 1021 Operator Licensing Examiner's Standard Section ES-601, in part establishes the following criteria that must be met by the licensee's requalification training program to be found acceptable by the NRC staff:

"1. At least 75% of all operators must pass the examination given by the NRC.

2. Utility examination results must not differ from the NRC results by greater than 90%."

Because of the results obtained, the NRC examiners declared the licensee's training program unsatisfactory.

Significant weaknesses identified by the inspectors concerned the failure of the operators to consistently perform the substeps of Emergency Operating Procedures (EOPs) in sequential order; and the failure of operating crews to display proper command and control functions when personnel assumed roles that differed from their normal watch standing duties i.e. a shift supervisor (SS) exchanged positions with the senior reactor operator (SRO), an SRO assumed reactor operator (RO) positions. Several operators also neglected to shutdown an emergency diesel generator exactly as specified in the procedure when load was reduced to a specified level.

Declaring the licensee training program unsatisfactory questioned the licensee's ability to operate Millstone 3 in a safe manner. Accordingly, NRC regional management requested the licensee to prepare a Justification for Continued Operation (JCO) that would provide a sufficient technical basis why Millstone 3 can continue to safely operate.

The JCO was prepared by the licensee and accepted by the Region I management by 6:00 pm on September 22, 1989. Specific actions required by the JCO, which were to be implemented at the start of the night shift at midnight on September 23 are outlined below:

1. Personnel who failed the NRC administered exam would not be allowed to stand watch until they had been reexamined by the NRC.

2. It was reemphasized that the SS was the primary person responsible to ensure compliance with the technical specifications.

3. A licensed management representative was placed on shift to ensure shift performance consistency, verify that EOP procedure usage was properly implemented and ensure proper use of and adherence to procedures.

4. It was stated that EOP steps that were numbered would be performed in sequence.

The conditions of the JCO were to be briefed to each oncoming shift by either the operations supervisor or unit superintendent.

The inspector verified proper implementation of the JCO by attending selected pre-shift briefings. The inspector verified that licensee management briefed crews on EOP procedure usage and implementation. Following the briefing, the inspector questioned operating crews and management representatives on EOP usage and technical specification compliance. Answers received indicated that the personnel were knowledgeable of NRC and licensee expectations. The inspector observed that operators were adhering to technical specifications and were observant of plant conditions. The inspector concluded through observation of crew performance, and questioning of personnel that the licensee had successfully implemented the JCO.

On September 25, 1989 an exit meeting was held in the NRC regional office in King of Prussia, Pennsylvania. There the licensee explained the reason for the failures, the reason for the differences in the NRC and licensee results, and the impact of the NRC finding on Millstone 1 and 2. Also at this meeting the formal NRC preliminary results were presented to the licensee. These findings did not differ from the September 22, 1989, results, however, these results included the written portion of the exam which was successfully completed by all operators. The licensee did not agree with all of the NRC findings, however, they agreed to take corrective actions.

To address the NRC finding that command and control responsibility suffered in the control room when individuals changed roles, the licensee agreed to reemphasize, during simulator training, what individual responsibilities were in the control room.

The licensee explained that several operators secured the diesel when it was loaded at 200 - 400 kilowatts (kw) rather than the 50 kw as required by procedure because of the difficulty operators had in reading the 0-8 megawatts (mw) meter. Since the meter increments are 200 kw, the licensee determined that operators elected to secure the diesel early rather than risk the possibility of the diesel tripping on reverse power. The licensee stated that their engineering analysis has shown that the diesel can be secured at 200 - 400 kw with no adverse affects; and the procedure would be modified accordingly.

The licensee stated that when plant-specific EOP's were being developed for Millstone Unit 3 from the Generic Westinghouse Owner's Group Guidelines, the decision was made to number all steps in EOP procedures. This was accomplished to conform with the Millstone Station Procedure Writers Guide writing format. The licensee stated that the operators were trained on which procedure steps could be performed out of sequence. The NRC explained that since Millstone Unit 3 had no EOP usage document that outlined which EOP steps could be performed out of sequence, the examiners had to rely on the Generic Westinghouse Guidelines which state that only steps that are not numbered may be performed out of sequence. To resolve this issue, the licensee agreed to develop an EOP usage guide that would specifically direct which procedural steps could be performed out of sequence.

Further, the impact of the NRC findings on Unit 1 was determined not to be a concern since boiling water reactor (BWR) procedures specifically allow steps to be performed in parallel. However, the utility acknowledged that the NRC findings are applicable to Millstone 2 and measures would be taken that are comparable to the ones discussed for Unit 3.

The licensee addressed some of the differences in NRC/licensee examination results to the difference in philosophy on EOP usage. To address this issue, the utility committed to retrain evaluators to sensitize them to the sequence of EOP step performance.

The NRC accepted the utility's proposals which were formally documented in a letter to the NRC on October 3, 1989.

On September 27 and 28, NRC inspectors evaluated the performance of two additional operating crews. The purpose of these examinations were to assess the adequacy of the licensee's corrective actions as outlined in the JCO and to obtain further observation of operating watch standing crews. Both operating crews responded adequately and demonstrated that the licensee's short term actions had effectively implemented the NRC required corrective actions. Based on review of the licensee's corrective actions, both long and short term, and acceptable performance by at least three operating crews, the NRC staff concluded the licensee can operate Millstone 3 safely. The inspector had no further questions on this matter.

3.3 Review of Plant Incident Reports

The plant incident reports (PIRs) listed below were reviewed during the inspection period to (i) determine the significance of the events; (ii) review the licensee's evaluation of the events; (iii) verify that the licensee's response and corrective actions were proper; and, (iv) verify that the licensee reported the events in accordance with applicable requirements, if required. The PIRs reviewed were: number's 3-89-14, 3-89-176, 3-89-84, 3-89-177, 3-89-109, 3-89-163, 3-89-170, 3-89-171, 3-89-165, 3-89-168, 3-89-160, 3-89-161, 3-89-162, 3-89-142, 3-89-138, 3-89-156, 3-89-167, 3-89-166, 3-89-178, 3-89-174. Upon review of the aforementioned PIRs, the inspector had no further questions.

3.4 LER 89-17, Noncompliance with Containment Isolation due to Administrative Error, 8/17/89

This event occurred on July 17 with the plant operating at 100% of rated power during the conduct of a routine quarterly valve surveillance test. After cycling recirculation spray system (RSS) discharge valve MOV 3RSS-MOV20D, the control operator noted the valve showed dual position indication (partially open) when the valve was stroked to the closed position. Operator and operations management review of the system condition concluded that the valve was fully operable as an injection valve since the normal and accident position for the valve was in the open position. The valve was left open and no further action was taken on July 17.

During a system status review on July 18, the duty shift supervisor determined MOV20D was not operable as a containment isolation valve (CIV) for containment penetration Z107. The valve should have been declared inoperable as a CIV at 6:16 a.m. on July 17 and the plant entered into the Technical Specification (TS) 3.6.3 action statement to either make the valve operable or secure the penetration within 4 hours. The failure to follow the LCO action on July 17 was a licensee-identified violation of TS 3.6.3.

Upon discovery of the discrepancy on July 18, the operating shift personnel took immediate corrective actions to log into the TS action statement, to close MOV20D, and to de-energize the power supply. An air test on the valve showed that the valve was fully shut in spite of the partially open indication; thus the isolation function was assured. Limit switches on the valve were subsequently adjusted and the valve was satisfactorily retested. The valve was declared operable for both the accident injection and containment isolation functions.

Licensee review of this event recognized personnel error as a contributing cause for the event since the shift personnel on July 17 failed to recognize the containment isolation function of the RSS pump discharge valves. However, the licensee identified (and reported in the LER) that the root cause of the event was inadequate administrative guidance on the definition of containment isolation valves. The fact that the valves receive no automatic closure signal in an accident condition, and the description of the valves in the FSAR led to a misinterpretation of the technical specification containment isolation requirements for the penetration. Inspector review of FSAR Table 6.2-65 noted the description for the RSS pump outboard valves could be easily misinterpreted. No inadequacies were identified with the licensee's conclusions.

The inspector reviewed the licensee's actions to prevent recurrence, which included providing guidance to shift personnel that all valves listed in FSAR Table 6.2-65 are containment isolation valves. This was discussed at a shift supervisor's meeting on August 10, 1989. The licensee also plans by February 28, 1990 to add this guidance to a permanent plant procedure. The completion of this action will be tracked by the licensee's system for tracking commitments, Engineering Form 31057-1, dated August 17, 1989.

The failure to follow the TS 3.6.3 LCO on July 17 was a licensee identified violation. No violation will be issued per the policy in 10 CFR 2, Appendix C, since the item had minor safety significance, the item was reported as required, and corrective actions were appropriate to prevent recurrence. (LII 89-16-01)

3.5 Inoperable Fire Protection Hose House

On August 4, 1989, when the plant was at 100% of rated power, monthly valve checks were conducted on Fire Protection Hose House No. 3. While performing the checks an isolation valve which supplies water to the house was found in the shut position. The valve was reopened and the hose house was restored to an operable condition. Technical Specification 3.7.12.6 requires the hose house to be operable; if not, the action statement requires backup hoses to be routed to the house from other operable stations as a compensatory measure. This was never accomplished.

Licensee review of the event revealed that the hose house was declared inoperable on April 5, 1989 because of a broken valve and stem assembly on a valve at the hose house.

On April 10, 1989, in preparation for repair of the broken valve a shift supervisor shut and tagged the isolation valve. However, due to a delay in delivery of material the valve was not immediately repaired. On July 25, 1989 maintenance requested that the hydrant isolation valve, which is downstream of the firemain isolation valve, be tagged shut to replace the defective valve. This was accomplished; the defective valve was replaced, the tag on the hydrant isolation valve was removed, and the hose house was declared operable. However, the safety tag on the fire main isolation valve was never removed. Additionally, when the isolation valve was found shut during the performance of the monthly surveillance on August 4, 1989 the danger tag originally installed on April 10, 1989 was not found.

To prevent recurrence of the event, the operations supervisor issued a memorandum to all shift supervisory personnel emphasizing that all pertinent information involving LCO's shall be documented on the shift supervisor's turnover report. Through discussions with the licensee, the inspector was informed that no definite reason could be established for the disappearance of the danger tag on the isolation valve. Currently, valve tagout audits are conducted quarterly, the most recent tagout audit conducted on the valve in April reported that the danger tag was still in place. This is the second incident involving a tagout problem in four months at Millstone 3. The first incident, documented as unresolved item (89-08-01), involved the improper tagging of electrical breakers. However, the second event (the hanging of the tag on the isolation valve) actually preceded the discovery of the first problem. Therefore, it is unlikely that any licensee actions that were taken as a result of the first event would have resulted in earlier discovery or prevention of the second tagout violation. Further, the specific causal factors of both events are considered unrelated.

The failure to follow technical specification 3.7.12.6 is a violation. However, because the event was identified, adequately corrected and reported by the licensee and is of minor safety significance, no violation will be issued per the policy in 10CFR 2 Appendix C (LII 89-16-02).

3.6 Staffing of Communication Channels During Emergencies

In a letter dated June 23, 1989, the licensee responded to an NRC staff request for information regarding open, continuous communications during emergencies. The NRC requires the licensee to maintain two communication networks, designated the emergency notification system (ENS) and the health physics network (HPN), that will be used to transmit plant operational and radiological information during an event. The NRC requires the licensee to also staff the ENS and HPN lines with a qualified individual during an event to communicate with the NRC. In a letter dated June 23, 1989 the licensee stated that it intends to use one technically qualified and trained individual to man the HPN and ENS telephone lines. The licensee stated that one qualified individual would be designated to serve both the ENS and HPN functions at the same time to minimize confusion and prevent transmittal of potentially conflicting information.

The inspector discussed this matter with licensee management and the licensee's emergency response personnel. The inspector expressed his concern that the licensee's apparent plan to use one individual to serve both functions would not be adequate to meet the information needs of the NRC response organization during an emergency. The licensee clarified their position and intentions by reference to a new emergency plan implementing procedure (EPIP) 4114, Revision 0, NRC Emergency Event Coordination and Communications, which was approved on June 26, 1989 and was effective on September 1, 1989. The inspector reviewed with the licensee the present locations of the ENS and HPN lines within the site emergency response centers. The licensee stated that they intend to have qualified individuals man the lines at each location, as required. These individuals will be in communication with the NRC to provide unit status information and parameter values as requested.

The licensee will augment the present emergency organization through implementation of EPIP 4114 by creating a new position Technical Information Coordinator (TIC) reporting to the Manager of Communications. This person will report directly to the Director of Site Emergency Operations (DSEO) and will provide the point of coordination between the NRC and the licensee. The Manager of Communications will respond to NRC requests for subjective information, such as future actions, etc. after conferral with the DSEO. The Manager of Communications would not be dedicated to the phone lines and that function would be provided by others in the technical support and radiological staffs.

Based on the above, the inspector concluded that the licensee's response plans and procedures appeared to be compatible with the NRC plans, and further, met the NRC staff's guidance provided in IE Notices 89-19 and 87-58, and the NRC letter to the licensee dated December 15, 1988.

However, the matter was referred to NRC Region I for further review and followup. The NRC responded to the licensee by letter dated September 7, 1989 to clarify NRC communications needs during an emergency. This letter also stressed the need for quantity and depth of information over the HPN line to aid NRC assessment of radiological conditions during an event. This information would need to be provided concurrent with operational data on the ENS. This matter was further reviewed with the licensee during an emergency preparedness inspection which started on September 11, 1989, which is documented in Inspection Report 50-423/89-20. The licensee's performance in this area was assessed during the conduct of the emergency drill in October, 1989. The drill inspection results are documented in Inspection Report 50-423/89-81.

No further followup by the resident inspector is warranted at this time. No inadequacies were identified.

4.0 Maintenance/Surveillance (IP 62703/61726/92702)

4.1 Observation of Maintenance Activities

The inspector observed various maintenance and problem investigation activities for compliance with procedures, Technical Specifications, and applicable codes and standards. The inspector also verified the appropriate Quality Services Department (QSD) involvement, safety tags, equipment alignment and use of jumpers, radiological and fire prevention controls, personnel qualifications, post-maintenance testing, and reportability. No inadequacies were noted. Portions of the following activities were observed.

4.1.1 Main Feedwater Isolation Valve Accumulator Leakage

On September 2, 1989 at 8:32 a.m., a low nitrogen pressure alarm was received on the C feedwater isolation valve (FWS-CTU 41C) B accumulator. That accumulator is used to supply the motive force to shut the valve in less than five seconds when a safety injection signal is received.

When the accumulator low pressure alarm was received, shift personnel declared the valve inoperable and entered the appropriate technical specification action statement 3.6.3. This action statement requires the valve to be returned to operable status within four hours or the plant must be shut down within the next six hours.

The cause of the low pressure alarm was attributed to a failed "O" ring on the accumulator. The "O" ring was replaced, the accumulator recharged with nitrogen, and the technical specification action statement was exited.

Inspector review of the accumulator "O" ring failure verified that the licensee entered the appropriate action statement, established proper isolation and performed an adequate repair. The inspector concluded that the licensee acted properly under the pressure of a restrictive technical specification, and no safety concern was noted.

4.1.2 Technician Error During Troubleshooting Activities

On September 25, 1989, while an I&C technician was performing troubleshooting on the D Feedwater Regulating Valve, (FCV-540-DO) the valve went completely shut. Steam generator level decreased until operators reopened the valve by assuming manual control. During the transient, steam generator level decreased to 22%; the reactor trip setpoint on low steam generator level is 18.1%. The cause of the event was technician error. The technician who was performing the troubleshooting changed his meter setting from voltage to current while the meter leads were still connected into the circuit. This action placed his meter into the circuit which caused the feedwater regulating valve to go into manual control. During this incident, the manual feedwater regulating control switch was in the shut position on the main control board, therefore, the valve closed.

The technician who made the error was counseled on the fact that meter position switches should not be changed while still connected to the circuit. The inspector reviewed the event and the corrective actions taken and had no further questions.

4.2 Observation of Surveillance Activities

The inspector witnessed selected surveillance tests to determine whether properly approved procedures were in use, Technical Specification frequency and action statement requirements were satisfied, necessary equipment tagging was performed, test instrumentation was in calibration and properly used, testing was performed by qualified personnel, and test results satisfied acceptance criteria or were properly dispositioned. Portions of the following activities were reviewed:

-- SP 3622.3 Auxiliary Feedwater Pump, Operational Readiness Test

-- SP 3443.1321 Protection System Set II Operational Test

4.2.1 Missed Fire Detection Surveillance

This event was documented in Licensee Event Report 89-16, which occurred when a fire detection surveillance was not performed on fire detection equipment in the control building, ventilation, and computer rooms within the required completion date of June 24, 1989. The cause of this occurrence was personnel error; the shift supervisors were aware that a surveillance had to be performed on the detectors, however, due to refueling work items, the completion of this surveillance was not aggressively pursued.

The missed surveillance was discovered on July 3, 1989 and compensatory fire watches were established in the affected areas. The surveillance was subsequently completed with all fire zones found to be operable, and the fire detection system was returned to service on July 24, 1989. To prevent recurrence of this event, shift supervisor turnover logs have been modified to include due dates for all surveillances which are past their scheduled completion date.

When the licensee failed to conduct surveillance on the fire detection system within the required time, the fire detection system in that area was administratively declared inoperable. Per plant technical specification 3.3.3.7 action statement "A" when a fire detection system is declared inoperable in an area, fire watches are required to be established. Fire watches were properly established by the shift supervisor, however, in only four of the seven locations. The inspector considers this event to be separate from weaknesses discussed later in Section 5.2.3 because the shift supervisor "knew" he had to post fire watches, but through oversight, all areas were not covered.

This is in contrast to the procedural weaknesses and lack of sensitivity to fire doors as is explained in detail 5.2.3. The failure to complete the action of the technical specification is a violation, however, since this issue was licensee identified, was promptly and acceptably corrected, properly reported, and of minor safety significance per the policy in 10CFR 2 Appendix C, no violation will be issued (LII 89-16-03).

4.2.2 Inoperable Sump Radiation Monitor

LER 89-18 reported a waste neutralization sump radiation monitor as being out of service since the commencement of plant operation in January of 1986. This monitor is used to detect any activity that may collect in the condensate demineralizer waste sump. If activity is detected, the monitor automatically isolates the discharge paths from the sump.

The monitor was declared out of service on August 2, 1989 by the licensee when it was detected that the automatic termination feature of the monitor was being tested for only one of the three discharge paths from the sump. The cause of this event was personnel error that led to procedure inadequacy; the surveillance procedure which tests the automatic termination feature was not properly reviewed to verify that all discharge paths from the sump would be isolated by the automatic termination feature of the monitor. When the remaining two paths were tested, the automatic feature responded properly.

Technical Specification 3.3.3.9 requires the radiation monitor to be in service during modes 1-5 and mode 6 during actual or potential releases of radioactive effluents from the waste neutralization sump. Because only one release path was being surveilled, the monitor was inoperable. When the monitor is inoperable, the applicable technical specification action statement requires that, before a release is made, the effluent is analyzed in accordance with the radiological offsite dose calculation manual. Additionally, the original release rate calculation and discharge line valves are to be independently verified by a second person.

Because these actions were not accomplished, this is a violation. However, since this event was licensee identified, was promptly reported and adequately corrected, and is of minor safety significance, per the policy of 10CFR 2 Appendix C, no violation will be issued (LII 89-16-04).

4.2.3 MSIV Operability Test - Use of Outdated Procedure

The inspector observed the performance of procedure SP3616.A.1 Main Steam Valve Operability Test from initial jumpering out of components to actual cycling of the valves. During the performance of the test, the inspector noted that personnel were knowledgeable of their duties, procedures were followed and test equipment was calibrated.

However, while technicians were establishing the initial conditions for the test, the inspector noted that the technicians did not have the latest revision to the procedure, which provided additional instructions to the technicians on when the test should be secured.

The change stipulated that the MSIV test buttons located on the back of the control panel should be released if the opening solenoids 3A, 3B, 4A and 4B do not change state immediately. This action is required to prevent the possibility of an MSIV going completely closed when steam is supplied on top of the piston. Past testing at Millstone has shown that if the 3A, 3B, 4A and 4B solenoids do not operate and supply a cushion of steam beneath the valve piston, the MSIV may close fully. When the inspector informed the technicians of this finding, they stopped their work and obtained the most recent change to the procedure.

Through conversations with the technicians, the inspector was informed that they were aware of the new additional instructions and, in fact, had suggested making those exact changes to the procedure as an improvement. The technicians obtained their copy of the procedure from one of the two official procedure files that are maintained in the control room. Through conversations with an operations supervisor, the inspector was informed that the procedure was inadvertently omitted from being updated with the latest revision because of clerical error. Although ACP 3.03 Document Control requires that procedure revisions be distributed, no violation will be issued for this error due to its low safety significance and the fact that this appears to be an isolated occurrence. (NCV 89-16-05)

4.2.4 Operation with Degraded MSIV Components

Procedure SP 3616A.1 verifies the operability of the main steam isolation valves by partially closing the valves from a test panel located behind the main control board. Partial valve closure is obtained by operating a series of solenoids which supply steam pressure to a piston located on top of the valve. The direction of valve movement will depend on which solenoids are operated. When the "open" solenoids are energized, steam is supplied underneath the piston and the MSIV is opened. When the "close" solenoids are deenergized, steam is supplied to the top of the piston, consequently, the MSIV will shut.

Each MSIV has two independent sets of closing solenoids that receive signals from separate logic trains. The logic trains supply an automatic close signal to the solenoids in the event that a containment isolation signal is generated or in the event of a steam line rupture. Plant technical specification 3.7.1.5 requires the MSIV to close within five seconds of an automatic or manual actuation signal, therefore it is necessary that the solenoids operate in less than five seconds in order for the MSIV to close within the desired time.

The partial MSIV closure is performed by depressing test buttons that are located on the back of the main control board. When this is accomplished, the following sequence occurs:

1) Solenoids 3A and 3B which vent the underside of the MSIV piston, shut. At the same time, solenoids 4A and 4B, which supply steam to the underside of the piston, open.

2) Five seconds after the above listed solenoids reposition, solenoids 1A and 1B, which vent the top of the MSIV piston, shut. Solenoids 2A and 2B, which supply steam to the top of the piston, open. This action causes the MSIV to close.

3) The MSIV will continue to close until it reaches the 90% open point. At this location, solenoids 2A and 2B close, and solenoids 1A and 1B open. This action will cause the MSIV to reopen.

4) When the MSIV reaches the fully open point, solenoids 4A and 4B will shut and solenoids 3A and 3B will open.

A valve is considered to have met the test acceptance criteria when it strokes to 90% full open and the closing solenoids 1A, 1B, 2A and 2B exhibit satisfactory voltage traces as seen on a visicorder/oscilloscope. The results of the test on October 10 indicated that the A and B MSIV valves functioned properly. Both valves stroked to 90% open and their solenoid valves exhibited proper traces on the visicorder/oscilloscope. However, when the C MSIV was cycled, the 2A solenoid exhibited signs of improper operation. Specifically, it required greater than 14 seconds to actuate. This is in contrast to the 2B solenoid which responded properly by actuating in less than 1 second. Also, the "D" MSIV could not be tested because its opening "test" solenoids did not operate. Although the procedure allowed the 3A, 3B, 4A, and 4B solenoids to be jumpered out and continuously energized, and thereby supplying steam underneath the MSIV, this was not performed since high risk testing was suspended due to a degraded grid voltage conditions.

The following day, the unit superintendent briefed the inspector on the status of MSIV testing. Specifically, plant engineering had analyzed the voltage traces on the 2A MSIV solenoid and had determined that additional testing was required to determine the reason for the slow solenoid operation. The superintendent stated that he considered the valve to be operable since the 2B solenoid functioned properly when tested and testing had not been completed on the 2A solenoid and therefore it could not be conclusively proven that the 2A solenoid had failed. The inspector noted the superintendents comments and stated that he also had adequate confidence that the valve would close, since the 2B solenoid had worked properly.

The inspector observed performance of the test on the C and D MSIVs. During the first two closure tests on the C MSIV, solenoid 2A energized after 5.5 and 5.2 seconds. A subsequent test on the 2B solenoid was satisfactory as it actuated in less than 1 second. The licensee then retested the 2A solenoid twice and it then responded satisfactorily. The licensee then declared the solenoid operable.

The inspector was subsequently informed by an engineering supervisor that the exact cause of the first four solenoid failures could not be determined. However, the data would be sent to the valve vendor, Sulzer of Switzerland, for analysis.

Review of the data by the vendor and the licensee did not identify a conclusive cause for the slow solenoid operation. Consequently, the licensee decided to increase the testing frequency of the valves from quarterly to monthly in an attempt to establish a base line of performance. The results of the increased testing will continue to be reviewed by the inspectors.

During the performance of the test, the inspector determined that since the 2A solenoid was out of service, the MSIV was in a degraded condition. Accordingly, a technical specification action statement should have been entered into as a means of addressing the valves reduced operability.

Review of the MSIV electrical system schematics and logic relays by the inspector verified that the MSIV solenoids receive their actuating signals from two separate logic trains. These actuating signals are received from the solid state protection system cabinets and are processed through master and slave relays which when deenergized will shut the MSIV by interrupting power to the closing solenoids. When the closing solenoids are deenergized, the 2A and 2B steam admitting solenoids will open, and the 1A and 1B cylinder vent solenoids will shut. This action will close the MSIV.

Through review of this logic sequence, it became apparent to the inspector that the MSIV solenoids are part of the actuating circuitry and not part of the activated equipment, i.e. the MSIV itself. Therefore, the inspector concluded that the licensee should have entered TS 3.3.2 Action 22, Engineered Safety Features Automatic Actuation and Logic Relays, when the solenoid was inoperable.

The inspector discussed his position with the unit superintendent at the several meetings that were held on this issue. The superintendent disagreed with the inspector's finding that Technical Specification 3.3.2 should be entered. The licensee believes that the solenoids were part of the valve, the actuated equipment, and therefore, TS 3.3.2 should not have been entered.

The licensee stated that since the valve would close within the five second time requirement of TS 3.7.1.5., no action statement had to be entered. The superintendent stated that a technical specification change to TS 3.7.1.5 would be considered to specify which action should be followed if a solenoid is inoperable. Review of the licensee accident analysis as stated in Chapter 15 of the Final Safety Analysis Report revealed that the plant is designed to cope with an open MSIV coincident with a faulted steam generator.

Through review of this issue, the inspector determined that when the 2A solenoid is in a degraded condition, the MSIV is not operating in accordance with the redundancy in actuation function that is obvious and intended in the circuit design. Therefore, this degraded condition should be addressed in the technical specifications. The technical specification that should be entered will be based on the NRC staff's review of the licensee technical specification change request.

Pending the Nuclear Reactor Regulation (NRR) staff determination to allow the licensee to operate the plant with an inoperable MSIV solenoid for a period of time that is greater than is currently allowed by TS 3.7.1.5, this matter is considered unresolved. This item will be reviewed when NRR staff evaluation is complete. (UNR 89-16-06)

4.2.5 Adequacy of Test Methods - Incomplete MSIV Testing

In addition to performing partial stroke testing of the MSIV's, plant Test Procedure SP 3616.A.1 is used to perform full stroke testing of the valves. Full stroke testing is required in order to verify that the MSIV will shut in five seconds as required by plant Technical Specifications 3.7.1.5. The licensee performs this testing when the plant is in cold shutdown using nitrogen as the motive force and during hot shutdown when steam is used. Currently, the licensee verifies that the valve will close in five seconds by only shutting the valve through use of the close switch on the main control board. When this is performed, a close signal is sent from the main control board switch to both actuation solenoids on the A and B train. Therefore, both trains are used to shut the valve. Consequently, the licensee does not have reasonable assurance that the MSIV will close within five seconds in the event of a failure in one MSIV logic train.

The Institute for Electrical and Electronic Engineers (IEEE) Standard 338 "Standard Criteria for the Periodic testing of Nuclear Power Generating Station Safety Systems", 1977 version, a document endorsed by regulatory guide 1.118 "Periodic Testing of Electric Power and Protection Systems," Revision 2, June 1978 which is committed to in the Millstone Unit 3 FSAR, requires in section 6.1 that "The operability of each redundant portion of the safety system shall be independently verified where practicable during reactor operation. The verification of operability during reactor operation shall include as much of the channel and load group under test as possible, including sensors and actuators, without interfering unacceptably with normal plant operations. Overlap tests are permitted where full functional tests are not practicable. Tests which would interfere with normal or safe plant operations should be scheduled during shutdown periods." Further, Section 5 of the Standard states, "Full functional testing may be supplemented by, but not replaced with continuity checks to determine failure modes." By not verifying that each individual logic train can shut the valve in five seconds, the licensee is failing to adequately test both redundant trains of the protective circuits. The testing that the licensee performs on each individual train currently consists of continuity checks which will not provide adequate assurance that one train of the protective system can shut the valve. The failure to adequately test both redundant trains of the MSIV protection system is a deviation (DEV 89-16-07).

5.0 Engineering/Technical Support (IP 37700/37828/92702)

5.1 Licensee ASME Procurement Position Accepted

Unresolved item 88-18-01 identified weaknesses in the license ASME procurement program. The licensee responded to the inspector's concerns in two letters dated February 16, 1989 and August 15, 1989, respectively. In the first letter, the licensee outlined the corrective actions that would be taken to address the inspector's concerns. The second letter outlined the licensee's corporate position on the procurement of materials from non-ASME material manufacturers or material suppliers.

Generic Letter 89-09 "ASME Section III Component Replacements" dated May 8, 1989 establishes an NRC position on this issue.

Specifically, the letter allows licensees to procure components from non-ASME Section III certified manufacturers provided the following criteria are satisfied:

1. The licensee must first establish that an equivalent Section III stamped replacement is not available. Cost can not be used as a justification for purchasing non-stamped parts.

2. The components must be procured under the licensee's Quality Assurance Program in accordance with 10 CFR Part 50 Appendix B and included in the plant operational quality assurance list.

3. Replacement parts should meet all other applicable requirements of Section III (including third party inspection by an authorized nuclear inspector) endorsed by NRC Regulations except that the Code N - symbol need not be applied.

4. The licensee must indicate such replacements in the Final Safety Analysis Report Annual Update and certify their compliance with the guidance contained in the Generic Letter 89-09.

The inspector reviewed the Section in Procedure ACP-QA-2.18 ASME Section XI Repair/Replacement Program, which provides instructions on the actions that should be followed when ASME Section III components are no longer available. The inspector concluded that the instructions contained in ACP-2.12 are consistent with the guidance contained in Generic Letter 89-09.

After completing review of the licensee position on procurement of ASME material; and upon examination of ACP-2.18 ASME Section XI Repair/Replacement Program, NRC staff review has concluded that the licensee's corporate position outlined in the letter dated August 15, 1989, is acceptable provided the licensee continues to follow the guidance outlined in Generic Letter 89-09. The NRC has also determined that if the licensee desires to deviate from the requirements of Generic Letter 89-09, a specific relief request must be applied for in accordance with 10CFR part 50.55a(3). This position was explained to the unit superintendent who acknowledged the inspector's comments.

5.2 Status of Previous Inspection Findings

5.2.1 (Open) Unresolved Item 423/84-04-08 Piping Stress Analysis

This item concerns the assumption of decoupled piping response when performing seismic analysis of piping systems supported from structural steel beams. Submittals by the licensee architectural engineer Stone and Webster Engineering and Northeast Utilities Service Company have so far only addressed the issue on a qualitative bases. Due to the theoretical nature of the item, Region based specialists and resident inspectors have concluded that this issue is a licensing concern and, therefore, it will be referred to the appropriate Branch of the Office of Nuclear Reactor Regulation for review.

5.2.2 (Closed) UNR 88-18-01 ASME Procurement Program Concerns

Previous inspector review of Millstone Station's programmatic controls for procurement of ASME rated components identified four weaknesses. (1) An ASME policy does not exist to address the procurement, issuance and installation of ASME materials. (2) The licensee continued to issue purchase orders to REC Corporation, a supply vendor, after REC had lost its ASME certification. (3) The REC Corporation was listed as a Q/A, category I supplier even though it had lost its only Q/A employee. (4) A review of purchase orders (PO) issued to REC generated at the site and Rocky Hill differed by six identifying an inability to uniquely track POs. The licensee was asked to address the inspector's observations in writing.

The licensee responded to the concerns on February 16, 1989 and agreed to address the programmatic deficiencies. The weaknesses would be corrected by updating administrative control procedure ACP-2.18 which provides guidance on the procurement of ASME components; updating the Approved Supplies List (ASL) to include a more complete description of what material a supplier was allowed to sell to the licensee; and, revising the supplier evaluation procedure QSD 3.02 which is used to audit suppliers to require an auditor to ask specific questions on the status of their QA employees.

Additionally, the licensee stated that they have the capacity to track purchase orders (PO) and that the difference in PO totals between Rocky Hill and the site was a result of personnel error.

The inspector reviewed the licensee actions and determined that they are adequate to address the weaknesses identified by the inspector. The inspector also noted that in addition to revising the ASL, the licensee requires individuals to recheck the ASL when equipment is received from a supplier to reverify that its status as a material supplier has not changed since the original order was initiated. The inspector concluded that the actions taken by the licensee has addressed the NRC staff concerns. This item is closed.

5.2.3 Fire Protection Weaknesses Addressed

Routine Millstone 3 Inspection Report 50-423/89-03 documented several instances of missed fire detection surveillances and fire doors being blocked open or opened without permission. Due to the recurring nature of these problems, the NRC requested in a letter on May 17, 1989 that the licensee provide its proposed plan of action to address these problems. The licensee responded by letter on August 18, 1989. In the letter, the licensee stated that the missed surveillances were due to the fact that fire detectors that were required to be tested were omitted from the surveillance procedure due to personnel error. A licensee review of technical specification surveillance requirements and their associated surveillance procedures that was completed on December 15, 1988, did not detect the error due to the scope of the review.

That review verified that the surveillance procedures covered all zones listed in the technical specifications. It did not verify that the surveillance procedure covered all five detectors in the zone. The licensee has subsequently changed the Millstone Unit 3 technical specifications to list all fire detectors in each fire zone. The licensee stated that the discrepancics in the fire detectors surveillance appear to be an isolated occurrence and are not indicative of an overall weakness in the technical specification review process.

To address the recurring problem with open or blocked open fire doors, the licensee has performed the following actions:

a) All technical specification required fire doors were labeled with signs indicating the door is required to be closed and locked and to contact the control room if the door must be blocked open.

b) Employee training will emphasize the importance of fire doors.

c) Security will notify operations if, when responding to technical specification fire door concerns, problems are identified with the door.

Through review of Plant Incident Reports (FIR) and License Event Reports (LER), the inspector noted a decrease in the frequency of fire door problems. Therefore, the inspector concluded that the licensee's corrective review to be adequate, and he had no further questions.

6.0 Security (IP 717107)

6.1 Security Event Reports

During a routine security records review at 2:14 p.m. on October 1, a security shift supervisor identified that an alarm had not cleared on Door 341, an entrance to a vital area at Millstone 3. Followup investigation by security personnel identified that the potential had existed since 3:31 a.m. that same day for unauthorized and undetected access to the vital area. Proper control of the area was re-established upon discovery. The area was checked by security and operations personnel and no anomalies were noted. The NRC HQ:DO was notified of the event per 10 CFR 73.71 at 3:37 p.m. on October 1.

The resident inspector arrived at the site at 4:45 p.m. and reviewed the vital area, the controls for the vital area, and the licensee's findings regarding how the event occurred. The licensee concluded, based on a preliminary investigation, that upon the completion of routine surveillance checks earlier that morning, the door alarm failed to reset, resulting in a partial loss of control of the vital area access. The basis for this conclusion was the data summary from the security computer.

Subsequent licensee review concluded that the door to the vital area remained secure through the period in question. Further, the licensee concluded the alarm system remained operable and capable of reporting unauthorized access. This was demonstrated based on tests conducted on October 18 to recreate the test sequence, which showed the "apparent" loss of alarm function was attributable to the manner in which data is sent from plant areas to the computer. The inspector reviewed the bases for the licensee's conclusions through interviews with security and computer personnel and a review of the computer data. No inadequacies were identified.

Based on the above, the licensee concluded the event was recordable per 10 CFR 73.71(c), but not reportable per 10 CFR 73.71(b). The licensee intends to document its conclusions in writing to the NRC. The written report will be reviewed during a subsequent routine inspection.

Notwithstanding the above, licensee review identified two corrective actions to improve performance in the areas of information transfer from the plant areas to the computer and in the console operator supervisor performance in the clearing of alarms. A change to the computer software is planned that will prevent clearing alarm conditions in the security computer until the condition is reset from the field. The supervisors will be counseled on performance.

The inspector had no further comments in this area. Followup of the event by contractor security and licensee personnel was prompt, thorough and effective in identifying areas for performance improvements.

7.0 Safety Assessment/Quality Verification (IP 30703/40500/90712/92702)

7.1 Evaluation of Licensee Self-Assessment Organizations

NRC experience indicates that utilities with effective self-assessment and corrective action programs achieve superior operating performance. Millstone Unit 3 has several oversight and independent assessment organizations that perform periodic audits and evaluations of the unit's performance. The inspector reviewed two Technical Specification (TS) required oversight committees - Plant Operation Review Committee (PORC) and Site Operation Review Committee (SORC) and the three (TS) required independent organizations - the Nuclear Review Board (NRB), Site Nuclear Review Board (SNRB) and the Independent Safety Engineering Group (ISEG), to evaluate the adequacy of the licensee's self-assessment abilities.

Periodically the inspector attended PORC, SORC and NRB meetings. At these meetings, discussions involving plant issues were full and open. At no time did the inspector observe a cursory review of an issue even though the detailed review caused schedule slippage. All meetings were conducted either with the required Technical Specification personnel or with suitable alternates in attendance. The inspector did not have any questions regarding the conduct of PORC or SORC meetings.

However, one area for improvement was noted in the conduct of NRB meetings. During a recent NRB meeting that the inspector attended, at times the topic of discussion would divert away from safety significant issues. The inspector concluded that due to the large volume of material that must be reviewed by members of the NRB in the limited time available, the NRB members should concentrate primarily on safety issues so that they receive proper attention.

The inspector reviewed the activities examined by the Independent Safety Engineering Group (ISEG). The ISEG currently consists of 14 individuals located at Connecticut Yankee, the Millstone site and the corporate office in Berlin. The ISEG conducts independent reviews of all four nuclear units, however, the majority of its efforts is directed towards Millstone Unit 3 which is the only unit that is required by TS to have an ISEG. The inspector noted that a wide range of topics from maintenance to operations were chosen for review, with ISEG findings presented to the appropriate unit superintendent for consideration. The inspector concluded that no single area was overly emphasized by ISEG and that ISEG currently performs a balanced examination of Millstone Unit 3 activities.

ISEG Reports were found to be technically adequate, thorough and complete. However, a weak area was identified in the station implementation, followup, and tracking of ISEG recommendations. Currently, ISEG does not track the implementation of their recommendations. Therefore, if a weakness is identified in a program, ISEG has no method to determine if that weakness was corrected. The inspector determined that without a formalized tracking system, significant ISEG findings may not get corrected in a timely fashion.

The inspector discussed this observation with the supervisor of the ISEG group who acknowledged the inspector's concern. The supervisor informed the inspector that the weakness had already been identified and procedures were in the process of being modified to establish a system to track ISEG recommendations. The inspector reviewed the proposed procedure changes and determined that they would address his concerns. The inspector encouraged the licensee to implement these changes in a timely fashion, and he had no further questions.

Occurrences caused by human error are examined by the Human Performance Evaluation System (HPES) Coordinator. This individual analyses occurrences caused by human error and attempts to determine the root cause of the event and recommend corrective actions to prevent recurrence. Yearly a report is prepared for the Manager of Nuclear Safety Engineering which details the results of the HPES investigations. The report divides the human errors into four major areas: (1) work place factors, i.e. bad labeling of components; (2) personnel factors i.e. attention to detail mistakes; (3) communications errors; and, (4) procedure errors. These human error categories are then graphed and trended, and recommendations are provided to prevent reoccurrence. The inspector reviewed an annual report and individual HPES reports and found them to be complete and thorough. The inspector concluded that the HPES system is an effective program to track human errors and recommend corrective actions to prevent reoccurrence.

The inspector reviewed Select NRB audits for completeness and adequacy; no inadequacies were identified. The inspector also verified that areas examined met technical specification requirements. The inspector had no questions regarding NRB audits.

Through observation of the oversight and independent committees and independent review of their activities, the inspector concluded that the Millstone self-assessment organizations are effective. However, NRB members should concentrate their efforts on safety significant issues. Also, the ISEG group should track their recommendations and licensee management must hold people responsible for the untimely implementation of ISEG recommendations on significant findings.

7.2 Review of Licensee Event Reports (LERs)

Licensee Event Reports (LERs) submitted during the report period were reviewed to assess LER accuracy, the adequacy of corrective actions, compliance with 10 CFR 50.73 reporting requirements and to determine if there were generic implications or if further information was required. Selected corrective actions were reviewed for implementation and thoroughness. The LERs reviewed were: 88-26-03; 89-16-00; 89-18-00; 89-1[illegible]-00; 89-20-00. The following LER's were selected for additional inspector follow up 89-16-00; 89-17-00; 89-18-06; 89-19-00 as previously described in this report.

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 report period.