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REGION I

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Licensee: North Atlantic Energy Service Corporation
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Facility: Seabrook Station

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Inspection Summary: This inspection report documents the safety inspections conducted during day shift and back shift hours. The inspections assessed station performance in the areas of plant operations, maintenance, engineering, plant support, and safety assessment/quality verification. An initiative selected this period included a review of the application of industry operating experience on pressure locking of motor actuated containment sump suction valves, coolant charging pump shaft failures, and the solid state protection system interface with the nonsafety-related inputs. In addition, a reactive inspection of an unplanned letdown system isolation was performed.

Results: One violation was identified concerning the use of unrestrained temporary equipment in the control room that could impact safety-related equipment during a seismic event. An unresolved item was updated on the pressure locking of motor-actuated valves. See the executive summary for an assessment of licensee performance.

EXECUTIVE SUMMARY

SEABROOK STATION
NRC INSPECTION REPORT NO. 50-443/95-01

<u>Plant Operations:</u> The operators performed well during routine and emergent operational activities. For example, operators stabilized plant conditions following an unplanned letdown system isolation that occurred due to a failed relay. Operations department management follow-up of the letdown system isolation identified some opportunities for improvement. Two minor errors in the operating logs for an emergency diesel generator resulted from a lack of attention to detail. A violation was identified involving the use of unrestrained temporary equipment in the control room that could impact safety related equipment during a seismic event. A walkdown of the safety related electrical distribution system found all switches and breakers were properly configured.

<u>Maintenance:</u> Maintenance personnel completed corrective and preventive work activities in a safe and controlled manner. A review of the changes made to the minor maintenance program to improve work efficiency determined that the work activities to be performed were within the skills-of-the-trade. The trip avoidance and regulatory aspects of replacing solenoids on two main steam isolation valves were well understood. Maintenance troubleshooting correctly determined that a diverging reactor vessel level indicating system (RVLIS) indication resulted from a loss of transmitter oil. The emergency bus undervoltage, atmospheric steam dump valve and the containment personnel airlock surveillances implemented the technical specification requirements. Surveillance testing anomalies were properly evaluated.

<u>Engineering:</u> Engineering promptly evaluated and benefited from industry operating experience. For example, a detailed engineering evaluation concluded that no immediate safety issue exists concerning the possible failure of the coolant charging pump shafts. Application of the related industry operating experience resulted in increased vibration monitoring and phase angle measurements. Also, a preliminary review of the interface between the solid state protection system (SSPS) and non-safety related inputs identified no concerns. Since the SSPS has ungrounded power supplies, a ground in a non-safety related circuit can be tolerated without degradation of the intended safety functions. Lastly, an unresolved item was updated involving the potential pressure locking of the motor-actuated containment sump recirculation suction valves, CBS-V-8 and 14.

<u>Plant Support:</u> The material condition of the plant improved as a result of preservation painting of the service water system piping, located in the service water slot, and door modification activities. Routine security and health physics activities were properly performed.

Safety Assessment/Quality Verification: The changes made in the format of the occurrence review committee seem to better focus resources on the significant issues. Minimum interaction between quality assurance and line management was observed at an interface meeting, which was the first meeting held since the end of the refueling outage.

TABLE OF CONTENTS

DETAILS

1.0 PLANT OPERATIONS (71707, 40500, 93702, 92901)

1.1 Plant Activities

The plant operated at essentially 100% power throughout this inspection period.

1.2 Routine Plant Operations

The inspector conducted daily control room tours, observed shift turnovers, attended the morning station manager's meeting, and monitored plan-of-the-day meetings. The inspector observed the executive director of nuclear production participate in several swing shift turnover meetings. The inspector checked and confirmed that operational activities were being performed in accordance with technical specification requirements. Operators swiftly responded to alarms. For example, when the primary component cooling water expansion tank high level alarm activated, operators promptly lowered level to clear the alarm. The inspector verified the accuracy of two tagging orders and conducted tours in the primary auxiliary building, the emergency diesel generator rooms, the residual heat removal vaults, the turbine building, the fuel storage building, and the service water pump house. Containment isolation valves were verified to be properly configured. During the tours and attendance at the various meetings, the inspector noted an adequate implementation of operational controls over plant activities and an overall good performance, including cognizance of the current plant configuration, by the operations staff.

1.3 Letdown System Isolation

On January 23, 1995, the control room operators responded to an unplanned letdown system isolation that occurred during the performance of surveillance test IX1662.222, 1-RC-L-460 ACOT-1, on pressurizer level channel 460 . The channel to be tested is normally de-selected on the main control board by control operators prior to the instrument and controls technician placing the channel in the test position. This ensures that the other two channels not being tested, channels 459 and 461, are active and provide pressurizer level inputs to the control system. When the I&C technician placed the level channel 460 in the test position, the letdown system isolated. Upon system isolation, the control room operators entered Abnormal Operating Procedure (AOP) OS1202.61, Loss of the Letdown System, and restored alternate letdown flow for control of reactor coolant system inventory. An increase in pressurizer level to 71% was noted, as well as, a slight decrease in reactor power to 3400 MWt. The operators stabilized plant conditions.

A review conducted by operations department management identified that although the operators stabilized plant conditions, they were slow to enter the AOP. The operators attempted to find the cause for the isolation first rather than entering and implementing the directions in the AOP. Use of AOPs will be addressed during operator training sessions at the station simulator to prevent recurrence. The inspectors reviewed the pressurizer level and thermal power chart recorder traces of the event. The transient was of a very short duration, no safety concerns were identified. The actions of operations management to follow-up and initiate corrective actions to better utilize AOPs for event response demonstrated excellent oversight of operational activities.

The system engineer and instrument and controls (I&C) technicians determined that relay J-10 (459D-X2), which normally defeats the input from the channel under test, did not operate properly. Work request 95W000263 was issued to troubleshoot and fix the cause of the letdown system isolation. The troubleshooting found that relay J-10 had faulty contacts, which were subsequently replaced and tested satisfactorily. The preliminary root cause of the relay contact problem was low voltage across the contacts that caused a high resistance connection and appearance of an open electrical circuit to a relay downstream of the contacts. I&C personnel initiated a request for engineering assistance (RES) to resolve the problem. The station engineering staff initiated a design change package to replace the relays that operate control loops during the next refueling outage. In addition, several procedures were revised to verify that the relay picks up and the contacts close prior to de-selecting the channel to be tested, which will prevent recurrence of the above event. The inspector determined the licensee's actions were appropriate and thorough with effective follow-up by maintenance and engineering personnel.

1.4 Engineered Safety Feature (ESF) System Walkdown

The inspector did an ESF system walkdown of the emergency electrical busses (4.16kv and 480v). Two 4.16kv busses (E-5 & E-6) supply vital safety-related electrical loads and are part of the "A" train and "B" train systems. The normal source of electrical power for these busses is from the station unit auxiliary transformers (UATs), which are fed from the station generator via the iso-phase ducts. An alternate source of power is the reserve auxiliary transformers (RAT's), which are fed from the 345kv distribution system. The alternate source of power automatically transfers to supply the vital busses if normal power is lost. In addition to the normal and alternate sources of electrical power, busses E-5 and E-6 have emergency diesel generators to supply the busses if off-site power is lost.

The 480v portion of the vital electrical system receives power from electrical busses E-5 and E-6 through substation transformers (4.16kv to 480v), which supply each train. The substations supply power to electrical loads and motor control centers (MCCs). The MCCs distribute electrical power to distribution panels, including 120/240 volt AC power.

The inspector reviewed the updated final safety report (UFSAR), technical specifications, system design requirements, and 10 CFR 50, Appendix A to ensure all requirements were met. The electrical system lineup was reviewed and found to be in compliance with station technical specifications and the UFSAR. With the assistance of a nuclear station operator (NSO), the inspector conducted a random internal inspection of several 4.16kv and 480v circuit breakers. The equipment was free of foreign material, with only a few minor exceptions. The visual inspection identified a 4.16kv circuit breaker door that had a fastener locking nut laying loose inside of the door in a wireway.

The door was capable of remaining closed; however, the missing nut fell down in the internal wiring harness, adjacent to an energized terminal board. The inspector expressed concern that a seismic event could potentially move the nut into contact with the terminal board causing an electrical short. The NSO removed the loose nut and further inspection identified several other cubicle doors with the similar problem of missing nuts in the opposite train. Inspection of these cubicles by the NSO did not locate the missing nuts. The inspector discussed the problem of having loose metal pieces inside of the switchgear cubicle with the electrical supervisor, who initiated a request for engineering services to determine the safety significance and root cause of this condition.

Several 480 volt safety-related circuit breakers were inspected and found to be in excellent material condition. Electrical components were free from any signs of overheating, which would indicate loose or high resistance electrical connections. Also, electrical maintenance personnel were observed during performance of thermography surveillance testing, which is capable of identifying overheated electrical components and/or connections. No problems were identified during the observation of thermography testing.

The vital switchgear rooms were properly ventilated with no fire hazards or seismic concerns identified during the walkdown inspection. The inspector determined that the safety-related emergency buses were properly configured to perform their intended safety function.

1.5 Unrestrained Temporary Equipment in Control Room (VIO 95-01-01)

During a routine inspection of the control room, the inspector observed numerous pieces of unrestrained temporary equipment in close vicinity to the main control boards and other vital equipment. The inspector expressed concern that the unrestrained temporary equipment could potentially impact safety-related equipment during a seismic event. The temporary equipment consisted of: two steel cupboards, nine steel filing cabinets, a coat rack, three steel bookshelves and a portable xerox machine. The inspector judged that the equipment had sufficient weight to cause damage. This potential safety issue was discussed with the shift superintendent, who contacted engineering for detailed evaluation.

Engineering personnel conducted a comprehensive walkdown of the control room and determined that much of the unrestrained temporary equipment needed to be removed or relocated to remote locations to meet the required station seismic requirements. Specifically, the equipment had the capability to impact the instrumentation sections of the main control board. The temporary equipment controls provided in Figure 5.1 of procedure MA 4.8, Control Of Temporary Equipment, were not followed prior to installing the temporary equipment in the control room. MA 4.8, step 4.1.2, specifies in part, concerning temporary equipment, that when such situations are unavoidable, they will be carefully evaluated to ensure that the potential impact on operable safety-related systems or components during a seismic event is minimized.

The inspector determined that the use of unrestrained temporary equipment in the control room was a violation of 10 CFR 50, Appendix B, Criterion V. which specifies that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. The controls of MA 4.8 to carefully evaluate the installation of temporary equipment were not followed. **(VIO 50-443/95-01-01).** The licensee promptly removed or secured the temporary equipment, as required.

The licensee conducted a plant walkdown to ensure that additional similar concerns did not exist elsewhere in the plant. In particular, the primary auxiliary building was inspected and found to have no potential seismic hazards, although some minor deficiencies were identified and corrected. Licensee management also discussed the need to secure temporary equipment with all operating shift personnel. The inspector determined that the licensee's response to the violation was prompt with proper actions taken to prevent recurrence. This item is closed.

2.0 MAINTENANCE (61726, 62703)

2.1 Routine Maintenance and Field Observations

During this inspection period, the inspector witnessed maintenance activities in progress, completed field work and various component line-up and system configurations intended to support specific preventive and corrective maintenance activities. At times, the inspection was pre-planned to observe certain key maintenance activities, while in other cases, field work was observed during inspection tours of the plant. Work controlled as minor maintenance was reviewed to ensure the activities were within skills-of-the-trade. In all cases, workers and supervisors were interviewed to determine the adequacy of work controls and acceptance criteria used to determine successful work completion. The following activities represent some of the maintenance and work control areas examined:

- WR 95W000169: Overtemperature Delta T Channel Failure
- WR 93W001283: Leak Repair of FW-V-147
- WR 94W004183: MS-V-86 Train B Main Dump Solenoid Replacement
- WR 94W002604: B Train CBA Compressor

<u>Main Steam Isolation Valve (MSIV) Solenoid Replacement</u>

On February 9, 1995, the maintenance staff commenced the on-line repair of main steam isolation valve (MS-V-86). A small oil leak was previously observed on the main dump solenoid while checking for leaks during performance of repetitive task MS-V-86-MAN 5 (94RI06017007). The system engineer initiated work request 94W004183 to replace the leaking solenoid. Although the leak was very small, the engineer determined that a possibly existed the leakage could rapidly increase causing the valve to inadvertently close. A plant trip would result, challenging the operators and plant equipment.

Prior to commencing the actual solenoid replacement, the technical support engineer held a trip avoidance briefing in the control room. The inspector observed that the briefing was very comprehensive. The discussion between maintenance, operations and technical support focused on all aspects of the work. Management and quality control presence were observed at the work site in the west pipe chase. Although the unit was in a four hour shutdown technical specification action statement, the work proceeded at an orderly pace, with no undue schedule pressure to complete the job.

During removal of the solenoid mounting bolts, the hex head on one allen screw was found badly galled, which caused a delay in removal of the component. The work crew determined that the fastener was damaged during a previous repair activity. The inspector later determined that no documentation of this deficiency existed. Maintenance and planning personnel did not note the galled fastener during work preplanning activities. Leaving a badly galled fastener installed on the main steam isolation valves is a poor work practice, which increased the time spent in the TS limiting conditions for operation. Using good techniques, the I&C technicians removed the badly galled fastener and solenoid. The new solenoid was installed with new fasteners.

After completion of the work, the valve was successfully retested as required by station procedures and declared operable. The technical specification limiting condition for operation was terminated. The licensee demonstrated an excellent capability to perform major trip critical repairs while at power in a safe, controlled manner. The galled fastener, left installed during a previous work activity, complicated the work and is considered a poor work practice.

Control Room Ventilation System Corrective Maintenance

During a routine inspection tour, a nuclear station operator observed the presence of bubbles in a sight glass installed on control room ventilation system "B" compressor. This system provides cooling to the station control room during normal and accident conditions and is classified as safety-related. Technical support engineers initiated work request 94W002604 to investigate and repair the leaks. Maintenance department personnel found several refrigerant leaks on and around the compressor, which were successfully repaired. Several leaks required more than one attempt before repairs were satisfactory. The system was evacuated and re-filled with freon, and successfully tested at 100% capacity. The system was restored to a normal operating line-up. The inspector observed the work in progress and reviewed the work package. The work package contained the proper documentation, reviews and the retest requirements. Operators restored the system after completion of post maintenance testing. The inspector concluded that the licensee properly repaired the system with qualified personnel and performed the task, as directed by station procedures.

Reactor Vessel Level Indication System (RVLIS) Transmitter Replacement

During a channel check, operators noticed an increasing deviation between the "A" and "B" train RVLIS indications. The limit was 15% deviation. As the deviation approached 15%, operators declared the "B" train indication inoperable, placing the unit in a seven day TS action statement. Technical support personnel had already initiated actions to obtain replacement parts, and develop a calibration procedure for the transmitter. The system engineer initiated work request 94W004187 to calibrate 1-RC-LI-1322. Instrument and controls (I&C) technicians used procedures IX1665.922 and IX1665.924 to remove and calibrate the detector. The local calibration of the transmitter resulted in no significant change in the RVLIS "B" train differential pressure or dynamic level indication. The system engineer initiated a scope change to WR 94W004187 to replace the transmitter as directed by station procedure IX1665.924. A pressure test was performed from the transmitter to the Magnex isolation valves. After examination of the failed detector, a loss of oil fill was determined to be the reason for the excessive oscillations, and a new detector was installed. The I&C technicians completed the calibration, and the transmitter was restored to service. The inspector determined that the licensee addressed the RVLIS oscillation problem with prudent engineering evaluation and repair activities.

2.2 Surveillance Activities

The inspectors performed technical procedure reviews, witnessed surveillance testing in progress, and reviewed completed surveillance packages to verify that the surveillance tests were performed in accordance with technical specifications, approved procedures, and NRC regulations.

The inspector observed portions of the following significant surveillance activities:

- LX0563.07: 4.16 KV Degraded Voltage Protection Monthly Surveillance
- EX1803.003: Reactor Containment Type B & C Leakage Rate Tests
- OS1430.07: Atmospheric Steam Dump Valve Quarterly Test

On January 11, 1995, the inspector witnessed portions of the containment personnel hatch airlock and door lock interlock verification test. The technical support engineers conducted the test using procedure EX1803.003, Reactor Containment Type B and C Leakage Rate Tests. The test is performed every six months in accordance with technical specification 4.6.1.3a,3b and 3c. The test supervisor properly performed all required prerequisites for testing and received permission from the unit shift supervisor prior to commencement of testing. The leakage was within allowable limits. The containment personnel airlock was restored to normal operation after completion of testing. The inspector reviewed the updated final safety report, station technical specifications and 10CFR50, Appendix J to verify that the testing properly met regulatory requirements. No deficiencies were identified.

On February 8,1995, the inspector witnessed a portion of surveillance test LX0563.07, 4.16 KV Bus Degraded Voltage Protection Monthly Surveillance. The electrical technicians were knowledgeable of the procedure and the testing was completed satisfactorily. During observation of the testing, an electrical supervisor stated that NRC Information Notice (IN) 95-05, concerning undervoltage protection relay settings being out of tolerance due to test equipment harmonics, had been received and was under review. The undervoltage relay described in the IN was Asea Brown Bovari (ABB) model ITE 27N, which is used at Seabrook Station for degraded voltage protection. The supervisor sent a letter to the off-site calibration facility that calibrates the station test equipment, requesting information concerning the issue. The licensee received a letter from the calibration facility stating that harmonic distortion testing was routinely performed and found to be very low (.3%). The licensee is continuing to investigate this issue. The inspector determined that the electrical supervisor was proactive and demonstrated a strong safety perspective.

During a review of a completed surveillance test on the "A" emergency diesel generator (EDG), the inspector identified two log readings for scavenging air temperature that were out of specification low, but not circled as required. The inspector discussed the issue with the unit shift supervisor (USS) who corrected the error. Subsequently, the licensee explained that the operator did not recognize the out of specification problem due a slightly different operating condition that was encountered on the day of EDG operation. The USS contacted the system engineer to determine the significance of the out of specification low readings. The engineer explained that the information was used for performance trending and was not an immediate operability concern. Operations department management discussed the log errors with the operator. The inspector concluded that these log errors did not affect operability, and were isolated in nature.

3.0 ENGINEERING (37551, 40500, 92903, 92700)

3.1 (Update) Unresolved Item 50-443/94-11-01: Binding Mechanisms of Motor-operated Flexible Wedge Gate Valves

On January 26, 1995 at Unit 2 of the Millstone Nuclear Power Station, the licensee determined that a potential existed for the containment sump recirculation suction valves to become pressure locked if the pump side gate valve disc (downstream side) leaked water into the valve bonnet from the water head of the refueling water storage tank. As a result, the containment sump recirculation suction valves may not open during postulated accident conditions as the water in the bonnet heats up and pressure locks the valve. Failure of the containment sump recirculation valves to open during an accident condition would challenge the operators capability to mitigate the consequences of a design basis loss-of-coolant-accident (LOCA). The inspector reviewed the applicability of this potential safety significant issue at Seabrook. The following documents were reviewed: NRC Preliminary Notification 95-04, NRC Information Notice 95-14, NRC Inspection Report 50-443/94-30, Volume 9 of NUREG-1275, North Atlantic engineering evaluation 93-33 and surveillance procedure OX1456.78. A meeting was held with the directors of nuclear engineering and licensing services to discuss the applicability of the issue. Several conference calls occurred between the NRC Region I staff and the licensee management staff to discuss this issue.

The containment sump recirculation suction valves, CBS-V-8 and CBS-V-14, at Seabrook were manufactured by Velan Engineering Company. The valves are encapsulated to provide an extension of containment. The sump recirculation suction valves are motor-operated, 16 inch diameter, flexible-wedge gate valves, which are required to open to perform their intended safety function. The upstream side of the sump recirculation suction valves takes a suction from the containment sump, which is maintained in a dry condition. The downstream side connects to the suction of the containment building spray and residual heat removal pumps. The downstream side of the valves is subject to the head of the water in the refueling water storage tank of approximately 42 psig.

Engineering evaluation 93-33 entitled "Thermal Binding and Pressure Locking of Safety-related Gate Valves," dated June 21, 1993, evaluated thermal binding, pressure locking and differential pressure locking mechanisms. The evaluation concluded that all safety-related, motor-operated gate valves required to open in an accident condition, would not experience binding or locking, and that no action is required to alter any safety-related motor-operated gate valve. Specific to the containment sump recirculation suction valves, the evaluation assumed that no credible method exists to fill the valve bonnets solid with water. The valves are cycled every three months in a dry condition for in-service testing. The licensee indicated that the containment sump valves use live load packing, which would tend to minimize packing leakage. If water did enter the valve bonnet, an air pocket is expected by the licensee to remain, mitigating the valve bonnet pressure rise. The inspector noted that at the end of this inspection period, no formalized calculations were performed to support these assumptions.

As a result of the recent issues at another pressurized water reactor, North Atlantic initiated a detailed engineering review of the susceptibility of the containment sump valves to pressure lock. Formal calculations are being performed. The evaluation will identify short and long term corrective actions. The inspector expressed concern that Volume 9 of NUREG-1275, issued March, 1993, states "Reliance on calculations of bonnet pressure relief in lieu of physical modification of the valve is not a reliable solution to the pressure locking problem. This is because several parameters used in the calculation are not constant and are subject to change." Licensee management indicated that the engineering calculations are being performed to support continued power operations. One possible mitigating strategy being considered by the licensee is to fill and maintain the containment sump full of borated water. The borated water in the containment sump would slow the rate of heat transfer from the steam/water mixture of a postulated LOCA, and would tend to decrease the rise of pressure in the containment sump valve bonnets. The licensee intends to make a design change to the containment sump valves, during the next refueling outage (OR04) scheduled to begin on November 4, 1995. The inspector determined that North Atlantic applied a proper safety perspective by promptly analyzing the potential pressure locking concern raised on January 26, 1995 at Millstone Unit 2.

This item will remain open pending completion of the current licensee engineering evaluation of pressure locking of the containment sump recirculation suction valves and subsequent NRC review. **(URI 50-443/94-11-01)**

3.2 Charging Pump Shaft Failures

The inspector reviewed the licensee's evaluation of NRC Information Notice (IN) 94-76, "Recent Failures of Charging/Safety Injection Pump Shafts," issued on October 26, 1994, and the charging pump maintenance history and vibration level trends. The following documents were also reviewed: Memorandum CEM 94-378, Operating Experience Screening Report No. OE12076, Engineering Evaluation 95-05, and Evaluations for NRC IN 88-23, "Potential For Gas Binding Of High Pressure Safety Injection Pumps," and the four associated supplements. On February 10, 1995, a conference call was held between the NRC and members of plant management to discuss the significance of this issue.

The technical concern involves a total of 21 charging pump failures reported by Westinghouse (W) plants worldwide. Sixteen of the 21 pump failures involved shaft failures, eight of which occurred in the last two years. Various root causes were identified including, high loads, debris ingestion, entrained gas, misalignment and incorrect system configuration. Entrained gas or gas slugs were associated with seven failures. All of the failed shafts resulted due to high cycle fatigue. The existing charging pump shafts have a revised W balancing drum locknut design and material change. The "A" charging pump has approximately 27,000 hours of operation, while the "B" pump has 29,000 hours of operation. W has not established any time limits on the number of operating hours. In memorandum CEM 94-378, dated December 30, 1994, technical support recommended replacing, as a conservative measure, both charging pump shafts during the next refueling outage (OR04) scheduled to begin on November 4, 1995. In December, 1994, the monitoring of charging pump vibration, as a precursor to failure, was increased from quarterly to weekly.

The inspector reviewed the charging pump vibration data for the previous four years of operation. The vibration velocity acceptance limit was .38 inches/second (ips). The majority of readings were less than .1 ips. With one exception, all readings were less than .38 ips. One of the November 3, 1994 readings on the "B" charging pump was .430 ips. After discussion with the technical support engineer, it was determined that the vibration readings for November 3, 1994 were incorrectly entered into the database. By mistake, displacement readings were entered into the database instead of velocity readings. The actual reading was .14 ips, which was less than the acceptance criteria. During this inspection period, the licensee began monitoring the vibration phase angle of the charging pumps. The inspector determined that the licensee increased the frequency of vibration monitoring of the charging pumps in response to the industry operating experience, and that the vibration levels were minimal.

In regards to NRC IN 88-23 and the four supplements on gas binding, operating experience at Seabrook does not reflect any gas pockets or charging pump cavitation noise. Licensee evaluation of Supplement 3 and 4 of IN 88-23 has not yet been completed. Engineering issued minor modification 92-504 to add a manual vent valve on a horizontal section of piping to confirm whether or not gases could collect. The modification has not been installed. Another factor evaluated was the number of pump starts, which could contribute to shaft failure. Seabrook performs approximately 17 charging pump starts per year, which is not considered an excessive amount of starts that could lead to shaft failure. The inspector determined that although no gas entrainment problems have been observed, to date, the issues contained in Supplement 3 and 4 have not been closed out.

The inspector concluded that engineering evaluation 95-05 considered the various mitigation factors to anticipate and avoid charging pump shaft failure. The charging pump vibration levels were low. An error in the in-service testing database was identified and corrected. Replacement of the charging pump shafts during OR04 is a conservative and prudent measure. There has been no indication of gas entrainment or pump cavitation. Supplements 3 and 4 of NRC IN 88-23 remain open. Monitoring of the vibration phase angle, which was initiated during this period, should provide enhanced monitoring capability as recommended by the NRC IN 94-76. The inspector has no further questions or concerns related to this matter.

3.3 NRC Information Notice 95-10: Potential Loss Of Solid State Protection System

NRC IN 95-10, dated February 3, 1995, describes a potentially generic safety issue concerning the possible loss of the one train of solid state protection system (SSPS) due to damage to non-safety related inputs to SSPS. A short circuit in one of the non-safety circuits, such as the turbine stop valve position circuit, could blow a power supply fuse that would also affect the safety-related portions of that train of SSPS. Supplement 1 to IN 95-10 was issued on February 10, 1995. The Salem Unit 1 nuclear power plant performed an inspection and determined that the preventive maintenance program for the SSPS power supplies did not detect degraded voltage regulators, capacitors, dirt, metal filings, age deterioration and a shorted wire. The inspector reviewed this industry information at Seabrook to determine whether or not similar problems exist. Discussions were held with operations, electrical engineering and regulatory compliance engineers. The pertinent electrical drawings, the physical layout of non-safety related equipment located in the turbine building providing inputs to SSPS, and the licensing basis documents were reviewed.

In response to the above industry operating experience, North Atlantic initiated a detailed engineering review, which had not been completed by the end of this inspection period. Engineering has determined preliminarily that the Seabrook SSPS design is not susceptible to the SSPS design problems. The power supply to SSPS at Seabrook is from an ungrounded inverter power supply. A ground fault on the circuit would not challenge the fuse. An ungrounded system can tolerate one ground fault, which would be detected by ground indication and promptly corrected. The design of the SSPS power supplies described in IN 95-10 were of the grounded type. An electrical design engineer referenced Request For Additional Information (RAI) 420.21 explaining that the NRC previously reviewed and accepted the SSPS interface with non-safety related inputs. An incorrect statement was included in the revised SNUPPS submittal made to the NRC. The submittal makes references to a grounded SSPS power supply system, which is actually ungrounded. Since the actual SSPS power supply is ungrounded, the configuration is more conservative, therefore, there was no apparent safety significance to the error. The regulatory compliance engineer indicated that a review of the error made in the RAI submittal would be performed along with the need to issue a corrected submittal.

The inspector discussed the existing SSPS power supply preventive maintenance (PM) program with the I&C department supervisor. The supervisor was aware of the issues associated with Supplement 1 to IN 95-10. A generic review of all power supplies to develop more comprehensive PM programs is being performed The information contained in Supplement 1 of IN 95-10 will be factored into the existing power supply PM review. The inspector had no further questions or concerns in this regard.

3.4 Calorimetric Flow Indicating Devices

The inspector met with engineering personnel to discuss the new feedwater system flow measuring devices that are installed at the station. The originally installed flow devices were subject to fouling, which introduced error into the calorimetric calculation used to determine reactor power and steam plant output megawatts. The newly installed instrumentation (ultrasonic) is a leading edge flow meter with greater accuracy and reduced fouling problems.

The station engineering department determined that the new flowmeters did not invalidate previous calculations that are assumed in the station accident analysis. Station calculation C-S-1-50023, Calorimetric Calculation Uncertainties, calculated the worst case uncertainty of the main plant computer system power calorimetric calculation performed at 100% rated thermal power (RTP). The worst case includes the use of steam flow and feedwater temperatures that are normalized using data from the ultrasonic flowmeters. The steam flow power calorimetric calculation uncertainty is +/- 1.78% of RTP, which meets the +/- 2% RTP assumed in the accident analysis. The inspector determined that the licensee had properly reviewed the change prior to installation.

4.0 PLANT SUPPORT (71750)

4.1 Radiological Controls

The inspector observed the implementation of radiological controls during tours in the radiologically controlled area (RCA). Health physics (HP) technicians kept the radiological survey maps updated, which were located at the entrance of the RCA. Portable hand held friskers and portal monitors were calibrated, as necessary. Strobe lights installed at the entrance to high radiation areas were working properly to alert plant workers of the need to observe additional radiological controls. Postings informed radiation workers of radiological hot spots. The inspector determined that the HP staff effectively implemented radiological controls to minimize the spread of contamination and incorporate the as-low-as-reasonably-achievable principle.

4.2 Security

The inspector observed security personnel on several occasions during morning rush hours at the main gatehouse. Searches were properly conducted as required by the station security plan and implementing procedures. Security officers were observed to be professional and courteous in the performance of their duties. The inspector toured the central and secondary alarms stations during the period and interviewed the operators concerning knowledge of the station and awareness of current status of station security systems. All security officers demonstrated proper attention to duties and were proficient at the assigned station. The security log contained the proper entries. The inspector observed a compensatory security watch established to facilitate a modification to a diesel generator room door. The security guard maintained proper access controls to this vital area, verifying that personnel entering the area had proper authorization before entry was granted. Supervisory involvement in routine security matters was evident.

4.3 Housekeeping

During routine tours of the plant, the inspector noted that the service water (SW) system piping and components in the SW slot area of the primary auxiliary building were painted during this inspection period. The preservation of the exterior surface of the piping improved the condition of the plant. In addition, several doors had been replaced or modified in the primary auxiliary building (PAB) to facilitate easier access to the areas. The inspector did observe oil dripping from two safety-related motor operated valves (MOV's), 1-SI-V-114 and 1-CC-V-1109, in the mechanical penetration area of the PAB. The oil problem was discussed with the unit shift supervisor to determine if a possible operability problem existed.

The plant systems support engineer responsible for the station MOV program reviewed the condition and met with the inspector. The observed oil leakage comes from the actuators main gearbox, which contains grease. The grease product is a mixture of approximately 92% mineral oil suspended in a lithium 12 hydroxystearate soap base. Oil weeps out from the soap base over time and the phenomenon is known as bleeding. Some of the oil from the actuator gear box weeps past the o-ring seals, which are designed and manufactured to contain grease, not oil. The licensee has a preventative maintenance program for limitorque actors. Station procedure LS0569.01, Inspection, Testing and PM of Motor Operated Valves, contains the requirements for lubrication condition monitoring and assessment, and the station has not previously identified any instances of MOV inoperability due to a lubrication related issue. The oil is not an indication of degraded grease and would not be a problem unless all of the oil seeps past the seals. Periodic inspection as directed by the station preventative maintenance procedure prevents this from occurring. The grease was last changed out on 1-SI-V-114 on 10/17/94 and 1-CC-V-1109 on 1/19/84.

The inspector concluded that the MOV oil leaks did not involve an operability issue and just needed to be cleaned as a good housekeeping practice. The MOV system support engineer possessed excellent knowledge and experience of the issues associated with proper MOV lubrication. The inspector had no further questions or concerns in this matter.

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (92700)

5.1 Occurrence Review Committee Changes

The inspector attended several occurrence review committee (ORC) meetings to assess the effect of changes made to the responsibilities and membership of the group. To improve the effectiveness of the corrective action program, plant management directed the ORC to review all corrective action documents, prioritize the issues by safety significance and assign the responsible department manager. Excellent discussion between the various ORC members was observed in reviewing issues. The human performance evaluation system coordinator pointed out that the ORC needed to be sensitive not to inadvertently usurp the duties of the station operation review committee (SORC). The inspector concluded that the changes made to the ORC enhanced the corrective action process.

5.2 Quality Programs Interface Meeting

On January 25, 1995, North Atlantic quality programs personnel conducted a interface meeting with members of all station departments to discuss the past performance of the station in the four areas of the systematic assessment of licensee performance (SALP) process. The nuclear quality manager conducted the meeting with assistance from key department personnel. The evaluation covered the period from August 1, 1994 to December 31, 1994. Although the report was detailed and contained good assessments, the inspector noted that very little discussion occurred during the meeting concerning the identified issues in the report. During discussions with several plant managers concerning the lack of in depth discussion of the report, it was noted that several managers felt that more time was needed to formulate plans for resolution of the identified concerns. The inspector concluded that the assessments discussed at interface meeting continue to improve.

6.0 MEETINGS (30702)

Two resident inspectors were assigned to Seabrook Station throughout the period. The inspectors conducted back shift inspections on January 26, February 8, 9, 15 and 18, and deep back shift inspections on January 14 and February 12 .

Throughout the inspection, the inspectors held periodic meetings with station management to discuss inspection findings. At the conclusion of the inspection, the inspector held an exit meeting with the Executive Director of Nuclear Production and his staff to discuss the inspection findings and observations. No proprietary information was covered within the scope of the inspection. No written material regarding the inspection findings was given to the licensee during the inspection period.

The DRP branch chief for Seabrook, Mr. Durr, visited the site February 13 and 14 to meet with the resident inspectors, tour the facility and interact with plant management. The inspectors participated in the systematic assessment of licensee performance (SALP) board meeting for Seabrook held on January 19 in the NRC Region I office.

A region-based inspector conducted an engineering inspection and exit meeting on February 6 - 10, 1995, IR 50-443/95-02