U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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License No.:	NPF-86
Report No.:	50-443/96-04
Licensee:	North Atlantic Energy Service Corporation
Facility:	Seabrook Station
Location:	Post Office Box 300 Seabrook, New Hampshire 03874
Dates:	May 5, 1996 - June 24, 1996
Inspectors:	David J. Mannai, Resident Inspector Jimi T. Yerokun, Senior Resident Inspector, Maine Yankee Al DeAgazio, Project Manager
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EXECUTIVE SUMMARY

Seabrook Generating Station, Unit 1
NRC Inspection Report 50-443/96-04

This integrated inspection included aspects of licensee plant operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

Plant Operations:

- Operations provided defense in depth to service water pump replacement activities by excellent questioning regarding safe handling of heavy loads. Alert action by nuclear system operators (NSOs) to secure the turbine driven emergency feedwater pump resulted in minimizing damage to the safety-related pump. (Section O1)

- Operators displayed an excellent persistent questioning attitude in identifying potential degradation of a safety-related electrical transformer (Section O2)

Maintenance:

- The turbine driven emergency feedwater pump was rendered inoperable when sparks were observed emanating from the outboard mechanical seal. It was later determined that the mechanical seal was aligned improperly during refueling outage OR04. The station promptly and effectively identified and corrected the immediate cause and returned the pump to an operable status. The apparent root cause determination concluded that corrective actions from a previous event in 1987 were not adequate to prevent recurrence in that operating experience was not adequately incorporated into design changes, procedures, training and pre-job briefings. The inspector found the completed significance Level A Adverse Condition Report (ACR) 96-413 for 1996 event, which was approved by the Management Review Team (MRT) and the Station Operating Review Committee (SORC), was not commensurate with safety significance of the event nor did it fully meet the guidance and expectations of the Seabrook Station Operating Experience (SSOE) Manual for Significance Level A ACR evaluations. (Section M1)

- Service water pump replacement activities were completed safely with some exceptions. The planning process failed to ensure the refurbished pump had the improved stuffing box bearing which increased the system unavailability time. The lifting device used to perform rigging of the service water pump was not manufactured to NUREG 0612 and North Atlantic Lifting Systems Manual requirements. The Quality Control organization identified this after the work had been completed. (Section M1)

Engineering:

- Engineering support in evaluating service water flow rate reduction encountered during surveillance testing following service water pump replacement activities was good. The evaluation, which concluded the pumps remained operable, identified the slight flow reduction was due to the AMEX-10/WEKO seal installation during refueling outage OR04. The potential for flow reduction was considered during the design change process. However, the flow reduction could have been better anticipated and potentially avoided the unplanned Technical Specification Action Statement entry. (Section E2)

- Technical Support's first self-assessment, which included 1995 performance of both system engineers and reactor engineers, was good. Further enhancements are planned for the next annual self-assessment. The technical support manager is considering implementation of periodic, preemptive, and reactive self-assessments. (Section E7)

Plant Support:

- The emergency preparedness Post Accident Sampling (PASS) drill was observed. The drill was aborted when the system drainage flow rate during system flushing was slower than expected. Personnel exhibited good communications and system knowledge. (Section P1)

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Report Details

I. Plant Operations

O1 Conduct of Operations

The plant operated at approximately 100% of rated thermal power throughout the inspection period. On May 21, 1996, the turbine driven emergency pump failed during the quarterly flow surveillance. The event was determined to be reportable per 10 CFR 50.72 (Section M1). Service water pumps 1-SW-P-41B and 1-SW-P-41D were replaced due to elevated vibration levels in the alert range. (Section M1 and E2)

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations. In general, good turnovers were observed, operators were attentive to plant status and equipment which was out of service. Control room supervisors provided sound oversight, particularly during key maintenance activities such as service water pump replacement and emergency feedwater system troubleshooting activities. Operations use of the ACR process to document problems was notably improved. Nuclear System Operators (NSOs) were alert and promptly secured the turbine driven emergency feedwater pump when sparks were observed in the area of the outboard mechanical seal. The swift action served to minimize damage to the pump such that the pump was readily repaired. Shift management excellently questioned the safe handling of heavy loads associated with the service water pump replacement activities. Consequently, a 10 CFR 50.59 safety evaluation was performed to evaluate conditions beyond the previously approved safe load handling path.

O2 Operational Status of Facilities and Equipment

O2.1 Safety-related Transformer (71707)

a. Inspection Scope, Observations and Findings

During the period, control room operators received several alarms associated with Bus 64, a safety-related bus which provides power to service water cooling tower fans 1-SW-FN-51A and 2-SW-FN-51B. A nuclear system operator (NSO) was dispatched and indicated an abnormal smell and humming noise coming from the associated transformer. The system engineer and electrical maintenance were contacted to evaluate the problem. Subsequent review indicated the alarms were due to a unrelated intelligence remote terminal (IRTU) issue and were not indicative of a problem with Bus 64.

System engineer evaluation determined the smell was not due to burnt insulation. The transformer was replaced during OR04 in November 1995 and operational parameters were normal for the transformer, which was lightly loaded. The licensee plans a thorough inspection at the next opportunity. Presently the allowed outage time (AOT) in Technical Specifications is eight hours, which is insufficient to perform the desired diagnostic testing and inspections. Since the only safety-related loads supplied by Bus 64 are the cooling tower fans associated with the service water (SW) system, the licensee has submitted a Licensing Amendment Request (LAR) to make the Bus 64 AOT consistent with SW AOT, which is seven days. This will facilitate a thorough inspection of the transformer.

b. Conclusions

The inspector concluded that operations personnel displayed an excellent persistent questioning attitude regarding anomalous conditions associated with the Bus 64 transformer. Since no actual objective evidence exists which would indicate a transformer performance problem at present, the plan to conduct a thorough diagnostic investigation pending receipt of an amendment was deemed appropriate. The inspector had no further questions.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (62703, 61726)

a. Inspection Scope

The inspectors observed all or portions of the following work activities:

- WR 96RM43009600: MOV diagnostic testing on 1-SW-V-140
- OX 1426.05: Diesel generator monthly surveillance

b. Observations and Findings

The inspectors found these activities to be appropriately performed in a thorough and professional manner with good oversight and involvement by supervision. Coordination and communication with control room operators was sound. All work observed was performed with the work package and/or procedures present and in active use. Involved personnel were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure.

M1.2 Emergency Feedwater Pump Inoperability (VIO 50-443/96-04-01) (62703,71707,40500)

a. Inspection Scope

On May 21, 1996 the turbine driven emergency feedwater pump (FW-P-37A) experienced a failure during quarterly surveillance testing when sparks were observed emanating from the pump outboard mechanical seal. The pump was secured and the event was reported to the NRC pursuant to 10 CFR 50.72. The problem was documented in adverse condition report ACR 96-413. Management Review Team (MRT) designated ACR 96-413 a Significance Level A (High Significance), priority 2 ACR and specified that a Cause and Failure Analysis be performed per OE 4.2. The inspector reviewed the event, held discussions with operations, maintenance and engineering personnel, reviewed maintenance history and procedures, and directly observed the disassembly and inspections performed on the electric driven EFW pump mechanical seals (WR 96W0001024). Later the inspector reviewed the completed MRT and Station Operating Review Committee (SORC) approved ACR evaluation, the SORC meeting minutes from meeting 96-063 and the Seabrook Station Operating Experience (SSOE) Manual. The SSOE describes the ACR process as well as the associated evaluation processes for determination of causes and significant events.

b. Findings and Observations

The licensee promptly developed troubleshooting plans under a priority 1 work request. The EFW pumps (electric and steam driven) employed at Seabrook Station are Ingersol Rand model 4X9NH-10 multistage (10) horizontal split casing centrifugal pumps with Durametallic Corporation mechanical seals (model 2D166243-R1). The licensee disassembled the outboard mechanical seal and determined that the outboard mechanical seal gland on FW-P-37A was found in the bottom of its fit. Upon disassembly, the shaft sleeve was discovered to have contacted (rubbed) the inside diameter of the throttle bushing. The shaft sleeve had approximately 0.005" gouge in it and the throttle bushing was chipped. The inboard seal was found to have 0.007" clearance between the top of the shaft sleeve and the throttle bushing inside diameter. The cumulative effect of these tight clearances resulted in contact within the seal assembly. The licensee determined the immediate cause was the shaft mechanical seal was improperly installed and aligned during refueling outage OR04 (November - December 1995). The inboard mechanical seal was inspected and aligned properly. The outboard mechanical seal was replaced and the surveillance satisfactorily completed.

The licensee also performed an inspection of the mechanical seals on the electric driven EFW pump (FW-P-37B) which revealed adjustments were also required on both the inboard and outboard shaft mechanical seals. This suggests that the pump was susceptible to the same mechanical rubbing as experienced on the turbine-driven pump. Both the inboard and outboard shaft sleeves had concentric burnish marks on them, as was found on the FW-P-37A inboard sleeve, indicating that it had been making contact with the throttle bushing. The outboard seal of that pump was also found in the bottom of its fit with approximately 0.0035" clearance between the shaft sleeve and the inside diameter of the throttle bushing (at the top). A subsequent review of the as-found data by the system engineer concluded that the electric emergency feedwater pump was capable of performing its design function if called upon to do so. The Startup Feed Pump (SUFP) which contains a similar mechanical seal arrangement was considered operable since the pump has approximately 4600 hours of satisfactory operation.

The licensee's investigation found that in January of 1987, prior to the station operating license, the licensee experienced a similar failure on the electric driven emergency feedwater pump where shortly after the pump start sparks and smoke were observed emanating from both inboard and outboard mechanical seals. The vendor representative was contacted and discussed the clearances and recommended relocating the gland to the top of its fit in the stuffing box. The gland was relocated to the top of its fit, and the pump was retested satisfactorily. Consequently, a caution statement and procedural step were added to procedure MS 0523.21, Emergency Feedwater Pump Maintenance, requiring the gland be barred prior to final torquing to ensure correct alignment.

The licensee review of work history showed the electric driven and turbine driven pump mechanical seals had not been worked on either pump between 1987 and the third refueling outage (OR03 for the electric driven pump) in 1994. Both pumps had work performed on the mechanical seals during refueling outage OR04 (November-December 1995) and thus the pumps had been in this condition since that time. The turbine driven EFW pump had two successful surveillance tests satisfactorily performed in December 1995 and February 1996.

The apparent cause determination concluded that corrective actions for previously identified problem or previous event were not adequate to prevent recurrence. Specifically operating experience from a similar event in 1987 was not adequately incorporated into design changes, procedures, training, and pre-job briefings. A contributing cause was a vendor fabrication deficiency. The design clearances and tolerances of this mechanical seal were insufficient to prevent damage during operation. Due to the design of the mechanical seal, minimal tolerances within the assembly required the use of precision instruments during setup to reduce the possibility of contact of the rotating assembly. Typically, the design clearances and tolerances of a mechanical seal are sufficient to allow for easy installation and setup. The design clearances and tolerances of this mechanical seal, however, were insufficient to prevent damage unless the installation technique used non-customary methods (i.e., use of dial indicators and feeler gauges). This resulted in the mechanical seal not being properly installed during OR04. The use of a dial indicator to aid in the installation would have prevented this event from occurring. The vendor manual and licensee procedure contained no such guidance or instructions.

Licensee corrective actions taken or planned included:

- The outboard mechanical seal on FW-P-37A was replaced and the inboard seal was checked and properly adjusted

- FW-P-37B mechanical seals were checked and properly adjusted

- Enhance maintenance procedure governing emergency feedwater mechanical seal maintenance/installation

- Engineering evaluate mechanical seal design change to increase the mechanical seal clearances

- Review the event in Mechanical Maintenance continuing training

The inspector reviewed in detail the completed ACR evaluation and the SSOE. The MRT classified the ACR Significance Level A (high significance) and specified that a Cause and Failure Analysis evaluation be performed. The cause and failure analysis and associated corrective actions were too narrowly focused and did not consider generic implications or address the several defense-in-depth barriers that broke down for this event to occur. The corrective actions did not address the cause(s). Specifically, ACR 96-413 documented corrective actions did not address the failure of corrective actions for a previously identified problem or event to prevent recurrence (failure to adequately incorporate operating experience) and thus were not focused on preventing recurrence. The was of particular concern to the inspector given the safety significance of the event and the completed evaluation had been reviewed and approved by both the Management Review Team (MRT) and the Station Operations Review Committee (SORC).

Additionally, the inspector found that the SSOE chapter 2 guidance indicates that Cause and Failure Analysis is normally performed for Significance Level B evaluations. Formal root cause analyses are required for reactor trips and engineered safety features (ESF) actuation, however it provides further guidance that the MRT may require that a formal root cause performed for other Level A - High Significance ACRs or Level B- Moderate Significance ACRs. Further procedure OE 4.1 Event Evaluation (Rev 03) describes the expectations for performing an event evaluation as a result reactor trip, ESF actuation, and/or other significant events. Specifically, the procedure addresses performing an event evaluation of major operating experience events or adverse conditions considered by station management to be of high significance. Further OE 4.1, Figure 5.2 Event Evaluation Response Guidelines specifies conditions which may require an event evaluation which include significant damage to plant equipment and major rework caused by inaccurate information in approved plans, procedures or component technical manuals.

Additionally, in refueling outage OR04 ACR 95-457 documented the electric-driven EFW pump thrust bearing had been installed backwards (NRC Inspection Report 50-443/95-15 detailed this event). The inspector reviewed the completed ACR evaluation which identified contract personnel performed the work with a procedure that assumed familiarity with the equipment that contract personnel did not have. The ACR minimum evaluation which was completed on March 27, 1996, contained a generic implication review of pumps with similar thrust bearings. The ACR evaluation of cause indicated written procedures and documents were not designed for less practiced users. This ACR was not included as part of the ACR 96-413 evaluation, yet it documented incorrect installation of components associated with the electric driven EFW pump and the same contract personnel worked on the failed turbine driven EFW pump.

c. Conclusions

The inspector determined the self-disclosing event was safety significant since the turbine driven EFW would not have performed its intended safety function had it been called upon to do so. In addition, misalignment was also found in the other train of EFW, though the licensee concluded the electric driven pump was capable of performing its intended safety function. The distinct possibility existed for a common mode failure of both trains of the EFW system. The inspector found the licensee promptly and effectively identified and corrected the immediate cause and restored the pump to an operable status. The Significance Level A, MRT and SORC approved, completed ACR evaluation was not commensurate with the safety significance of the event and did not fully meet the guidance contained in the SSOE. Specifically, the inspector concluded that SSOE guidance strongly suggested that a formal root cause evaluation in conjunction with an OE 4.1 Event Evaluation would have been appropriate in this case given the Significance Level A ACR designation. Consequently the limited Cause and Failure Analysis and associated corrective actions were too narrowly focused and symptom oriented and thus did not address root cause(s). Further other similar events were not fully considered when performing the evaluation. The incorrect installation of the mechanical seal assembly for the turbine driven EFW pump, which resulted in the potential for a risk significant system being incapable of performing its intended safety function, was a violation. (VIO 50-443/96-04-01)

M1.3 Service Water Pump Replacement (URI 50-443-96-04-02) (62703, 61726)

a. Inspection Scope

The inspector observed maintenance activities (RTS96RM23722600) surrounding the replacement of the service water (SW) system pump 1-SW-P-41-D. The station had decided to proactively replace the pump, due to elevated vibration levels (alert range). The inspector attended the prejob briefing, reviewed the work package and associated procedures and held discussions with Maintenance, Operations and Reliability and Safety Engineering personnel. Specifically the inspector reviewed the following procedures and documents:

- Maintenance procedure MS 0253.06 (REV 03), Johnston Vertical Service Water Pump Maintenance
- Operations procedure OS 1016.09 (REV 01, Chg. 10) Operability Inspection of the Ocean Service Water Pumps With Divers
- Section 9.2 of the Updated Final Safety Analysis Report (UFSAR),
- Technical Specifications Section 3.7
- NUREG 0612

- North Atlantic Lifting Systems Manual

b. Observations and Findings

The inspector found the overall conduct of maintenance activities were very effective with exceptions identified by the licensee. The planning process effectively evaluated the associated risk of performing the maintenance at power, with excellent involvement from Reliability and Safety Engineers. The maintenance department made excellent use of operating experience from both the station and the industry. Pre-job briefings were thorough and comprehensive. Operations personnel raised an excellent question regarding potential heavy load impact on the service water system during SW pump rigging activities. A 10 CFR 50.59 SORC approved safety evaluation was subsequently performed and temporary piping supports were installed during pump rigging activities. The maintenance was performed by knowledgeable personnel using appropriate procedures. One problem encountered during the maintenance involved inadequate preplanning in that the replacement pump stuffing box unexpectedly did not contain the improved style cutlass bearing modification. Consequently, a notable delay occurred while the stuffing box was machined and the modification implemented. The unexpected work scope increase was performed under WR 96W000941. Post maintenance testing revealed a reduction in service flow rates by a small percentage. (See Section E2)

Another licensee identified problem was that slings used to rig the pump were not the required safety factor of 10:1 required by North Atlantic Lifting Systems Manual and NUREG 0612. Specifically, after the work had already been performed, Quality Control (QC) personnel identified a safety factor of 3:1 existed vice 10:1 required by the North Atlantic Lifting System Manual after the work had been performed and initiated ACR 96-430. Pending completion of the ACR evaluation, suspect lifting devices have been appropriately tagged and their use prevented. The lifting device used had been manufactured under Request for Engineering Services RES 94-261 and built to comply with ANSI standards. Licensee investigation subsequently revealed that the lifting device, which was manufactured to meet the ANSI B30.20 requirement with a safety factor of 3:1, by default may have satisfied the NUREG 0612 and North Atlantic Lifting Systems Manual required safety factor of 10:1. Otherwise the licensee showed excellent regard for safe handling of heavy loads during the service water pump replacement activities.

c. Conclusions

The inspector determined the safety-related work was completed safely according to station procedures with some licensee identified exceptions. The planning process, overall, was very good from both risk assessment and safety perspectives. Prejob briefings and use of operating experience were very effective. However, the planning process failed to ensure the replacement pump contained the proper stuffing box bearing which resulted in an unexpected work scope growth and increase in the unavailability time for the risk significant system, with the plant at full power. The potential failure to use lifting devices with the required safety rating was considered a self-identified performance-based programmatic weakness regarding the safe handling of heavy loads. The identification of the problem was considered an excellent example of defense in depth provided by the QC organization, albeit after the fact. Maintenance initiated a separate ACR to document both problems from a project planning standpoint. This item will remain unresolved pending NRC review of the licensee's determination of the lifting device safety factor and evaluation of associated programmatic vulnerabilities. (URI 50-443/96-04-02)

III. Engineering

E1 Conduct of Engineering

E1.1 General Comments (37551, 71707)

System and Design engineer support of the service water pump replacement activities was very effective. In particular, the system engineer promptly provided information that supported continued service water system operability when maintenance department discovered deteriorated set screws on the service water pump shaft coupling assemblies on the service water pumps that had been removed following installation of refurbished service water pumps. Through a review of station records the system engineer determined that all four SW pumps presently installed contained set screws of the optimum stainless steel material for ocean water service. Previously the licensee updated the service water pump design to require use of Type 316 stainless steel set screws in the shaft coupling assemblies due to deterioration observed earlier in the station operating history. The newly installed pumps contained the proper material.

E2 Engineering Support of Facilities and Equipment

E2.1 Service Water Train "B" Flow Surveillance (61726)

a. Inspection Scope

On May 15, 1996, operators performed the quarterly surveillance test on the "B" train of Service Water (SW) system pumps 1-SW-P-41B and 1-SW-P-41D. The test procedure, OX1416.04, Service Water Quarterly Pump and Discharge Valve Test, revision 08, required that pump flow be adjusted to 10,500 ± 100 (10,400 to 10,600) gallons per minute (gpm) for each pump flow through the Primary Component Cooling Water (PCCW) heat exchanger. To obtain this flow, the procedure required that the PCCW heat exchanger outlet valve, 1-SW-V-17, be throttled. The flow rates obtained during the surveillance tests were 10,100 gpm for pump 1SW-P-41D and 10,300 gpm for pump 1SW-P-41B. Since the obtained flowrates were less than required by the procedure, operators declared both pumps inoperable, rendering the "B" train of Service Water (SW) system inoperable, and entered Technical Specification 3.7.4 action statement which required that the train be restored operable within 72 hours or a plant shutdown be initiated.

b. Observations and Findings

The inspector reviewed the surveillance test results, the pumps' performance curves, and observed portions of the test activities. In trying to determine the cause of the low pump flows obtained, the licensee focused on recent modifications in the SW piping as the cause of the reduced pumps flowrates. The inspector raised questions concerning other possibilities such as the potential for heat exchanger fouling, inadequate tide height, and pump degradation affecting the flows obtained. The licensee had eliminated heat exchanger fouling since the indicated differential pressure across the heat exchanger was acceptable. Also, the "B" train strainer had been inspected and found to be clean. The tide height was not an issue since, the design was such that the pumps will perform at the lowest tide height and the tide height at the time of the test was not low. While the test criterion was not satisfied, the pumps were determined not to be degraded because a review of head/flow test data indicated that the points fell on or near the composite head/flow curve for system performance analysis and well above the minimum curve that would be indicative of a pump degradation. The inspector verified this test data. The test problem was therefore attributed to the system test alignment which did not properly consider the impact of recent modifications to the system. An adverse condition report (ACR) 96-391 was generated to address this problem.

It appeared that the train's flow characteristics had been slightly changed after the installation of AMEX-10/WEKO seals in the system piping via DCR 95-012 during the 1995 refueling outage. The licensee had determined then that a change to the test flowrate was not required based on the post modification test results. However, this determination appeared inadequate since the result obtained then had been close to the test requirement with a very close margin which could have been increased by adjusting the required test flow rate. The problem was determined to be with the procedure requirement for a set flow to be achieved by throttling the PCCW heat exchanger outlet valve, 1-SW-V-17. A procedure change request (Number 11) was initiated to change the test flow rates from 10,500 $\pm$ 100 to 10,000 $\pm$ 100 (9,900 to 10,100) gpm. The basis and justification for the change was documented in an OE 4.5 operability determination.

c. Updated Final Safety Analysis Report (UFSAR) Reviews

The inspector reviewed the applicable portion of the UFSAR and noted the following. Section 9.2.1, Station Service Water System, stated that each train of SW is supplied by two redundant pumps with each pump capable of supplying 100% of the flow required by each flow train to dissipate plant heat loads during normal full power operation. Table 9.2-1 indicated that a flow of 10,500 gpm for normal operation and a flow of 9,300 for Post-LOCA Recirculation Flow with Loss of Offsite

Power would be available. However, the revised surveillance flowrate was for 10,000 ± 100 gpm. While this flowrate was adequate considering Post-LOCA Recirculation flows, it was not sufficient for the normal operation flowrate of 10,500 gpm described in the UFSAR. The discrepancy between the UFSAR pump flowrates and the revised acceptable surveillance flowrates were discussed with the licensee. The licensee had noted this discrepancy and had generated an adverse condition report (ACR), 96-429, to address the issue. The current design basis flow requirements are reflected in calculations 4.3.8.72F, Revision 3, SW System Steady-State Analysis, and C-S-1-86901, Containment Pressure Following a LOCA with Reduced Flow in PCCW Heat Exchanger, Revision 0. The flows are 7,096 gpm to the PCCW heat exchanger and 1,409 gpm to the DG heat exchanger for a total of 8,508 gpm (reflecting summations in computer simulation). The QC department identified that the design minimum flow rates listed in Table 9.2-1 were not the same as the OE 4.5 operability determination that was supported by the aforementioned calculations and supporting 10 CFR 50.59 evaluation. The licensee determined that these two calculations bounded and demonstrated that a flow of 10,000 gpm is capable of performing the SW system design basis safety function.

d. Conclusions

The inspector reviewed the changes made to the procedure (Change #11), the operability determination and concluded that the licensee had performed a thorough review and evaluation of the problem and had properly instituted measures to resolve the issue. There was good support from engineering. The issue was promptly brought to licensee management attention and discussed in the morning meeting. The only weakness identified was that the need to revise the IST reference flow rates in procedure OX1416.04 following the installation of the AMEX-10/WEKO seals modification was not realized. While this was of minor safety consequence, it resulted in an unplanned TS limiting conditions for operations (LCO) action statement entry. The UFSAR discrepancies had no safety consequence. The licensee initiated actions to resolve the UFSAR discrepancies. The inspector had no further questions.

E7 Quality Assurance in Engineering Activities

E7.1 Technical Support Self-assessment (37551, 40500)

a. Inspection Scope

The inspector reviewed 1995 technical support self-assessment report and attended the meeting which presented the results to the system engineers. In addition, discussions were held with the technical support manager and the technical support group instruction (TSGI-03, Rev.0) which was used as the basis to conduct the assessment was reviewed.

b. Findings and Observations

The report, which was the first technical support self-assessment conducted, included a system engineer section which contained a survey of the station view of system engineer performance, review of 56 work requests, technical support engineering evaluations, temporary modifications, plant modification, corrective actions training. A separate section was devoted to a reactor engineering self-assessment. Each report section contained strengths, weaknesses and recommendations. The evaluation found no major weaknesses.

c. Conclusions

The inspector considered the first annual self-assessment a good initial self-assessment. The report itself was reasonably self-critical and met the attributes outlined in the TSGI-03. The technical support manager is presently considering performance of periodic preemptive and reactive self-assessments. Also, development of key performance indicators is underway and system engineer performance expectations. The customer oriented survey was a particularly good approach and will undergo some refinements for the next annual self-assessment to provide more succinct feedback from the other organizations to which technical support provides support. The inspector had no further questions.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 General Comments (71707, 71750)

The inspector observed implementation of radiological controls during tours in the radiologically controlled area (RCA). Random sampling of portable hand held friskers and portal monitors demonstrated that they were calibrated as required by station procedures. The inspector determined by observation of several tasks in the radiologically controlled area that the licensee was effectively implementing radiological controls to minimize the spread of contamination and incorporating as-low-as-is-reasonably-achievable principles.

P1 Conduct of EP Activities

P1.1 Reactor Coolant Post Accident Sampling (71750)

a. Inspection Scope

The inspector observed the semi-annual health physics drill and Post Accident Sampling System (PASS) testing (RTS 1-CHEM-18-CP-Q01). The inspector reviewed the governing procedure (CS 09025.01, Revision 9) and the emergency preparedness (EP) requirements. The inspector attended the debrief and discussed the drill results with chemistry and EP personnel.

b. Observations and Findings

The drill and PASS sample were stopped partway through the exercise due to a problem identified by the chemistry technician. While flushing the system with demineralized water, the technician noted that the water was draining slower than expected. Complete drainage took over 30 minutes while the usual drainage time is less than 5 minutes. The inspector noted excellent communication between the chemistry technician, the chemistry training instructor, the control room, and the chemistry supervisor. This resulted in the conservative decision to abort the test until further determination of problem could be resolved.

The inspector noted that the opportunity for assessment of the chemistry technicians response to an actual problem was not achieved to the fullest extent. The chemistry training instructor played the dual role of trainer and PASS Coordinator, which resulted in a situation that differed from an actual accident type scenario. Based on discussions with the EP representative, the next drill will include the normal PASS coordinator.

The drainage problem was documented in an adverse condition report (ACR). The initial troubleshooting was to refill and flush the system with demineralized water again. The water drained within the normally expected time frame (within two minutes). The ACR will be used to trend the problem. The inspector noted that the licensee identified the lack of a foreign material exclusion (FME) cover on the funnel used to fill the system with demineralized water. The chemistry department issued a work request to complete the corrective action of installing a cover for the funnel. The RTS was completed at a later time and the health physics drill has been rescheduled to meet the semi-annual requirement

c. Conclusions

The inspector noted good communication between personnel and knowledge of the system resulted in the decision to suspend the drill and the PASS sample RTS. The lack of an foreign material exclusion (FME) cover was a possible contributor to the failure of the test, but the licensee identification of the FME issue was noted as a strength. The potential for using the problem encountered to assess emergency response was diminished by the absence of the actual PASS coordinator. The inspector had no further questions.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71707, 71750)

The inspector observed security force performance during the course of routine inspection activities. Protected area access controls were noted to have been properly implemented during random observations. Individuals with visitor badges were noted to have been properly in the control of designated escorts. Additionally, alarm station officers were observed to be attentive to alarm and surveillance stations and aware of the status of security systems.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management, following the conclusion of the inspection period, on July 2, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X2 Other NRC Activities

On May 29-31, 1996, a special NRC inspection was performed by region-based specialist inspectors to review plant activities at the request of the Massachusetts Attorney General relative to concerns that were expressed to the public by the C-10 Research and Education Foundation (C-10) pertaining to a potential radiological release. NRC Inspection Report 50-443/96-05 documented the inspection results.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

W. Diprofio, Unit Director
G. Kline, Technical Support Manager
R. White, Design Engineering Manager
J. Peterson, Maintenance Manager
J. Grillo, Operations Manager
B. Seymour, Security Manager
W. Leland, Chemistry and Health Physics Manager
G. MacDonald, Quality Services Supervisor

NRC

Albert W. DeAgazio, Project Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observation
IP 62/03:	Maintenance Observation
IP 64704:	Fire Protection Program
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 73051:	Inservice Inspection - Review of Program
IP 73753:	Inservice Inspection
IP 83729:	Occupational Exposure During Extended Outages
IP 83750:	Occupational Exposure
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened — Violation 50-443/96-06-01, "Turbine Driven Emergency Feedwater Pump Failure Due To Incorrect Mechanical seal Installation"

Unresolved Item 50-443/96-06-02, "Potential Inadequate Service Water Pump Lifting Device"

Closed — None

Discussed — None

LIST OF ACRONYMS USED

ACR(s)	-	Adverse Condition Report(s)
ANSI	-	American Nuclear Standards Institute
AOT	-	Allowed Outage Time
CFR	-	Code of Federal Regulations
DCR	-	Design Change Request
DG	-	Diesel Generator
DRP	-	Division of Reactor Projects
EFW	-	Emergency Feedwater
EP	-	Emergency Preparedness
ESF	-	Emergency Safety Features
FEMA	-	Federal Emergency Management Agency
FME	-	Foreign Material Exclusion
FW	-	Feedwater
GPM	-	Gallons Per Minute
IP	-	Inspection Procedure
IRTU	-	Intelligence Remote Terminal Unit
IST	-	Inservice Testing
LAR	-	Licensing Amendment Request
LCO	-	Limiting Conditions for Operations
LOCA	-	Loss of Coolant Accident
MOV	-	Motor Operated Valve
MRT	-	Management Review Team
NPF	-	Nuclear Power Facility
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
NSIC	-	Nuclear Safety Information Center
NSO(s)	-	Nuclear System Operator(s)
NUREG	-	Nuclear Regulation
OE	-	Operations Experience
OEDO	-	Office of the Executive Director of Operations
OR03	-	Refueling Outage No. 3
OR04	-	Refueling Outage No. 4
PAO	-	Public Affairs Office
PASS	-	Post Accident Sampling System
PCCW	-	Primary Component Cooling Water
PDR	-	Public Document Room
QC	-	Quality Control
RCA	-	Radiologically Controlled Area
RI	-	Region I
SALP	-	Systematic Assessment of Licensee Performance
SORC	-	Station Operating Review Committee
SSOE	-	Seabrook Station Operating Experience
SUFP	-	Startup Feed Pump
SW	-	Service Water
TS	-	Technical Specifications
TSGI	-	Technical Support Group Instruction
UFSAR	-	Updated Final Safety Analyses Report
URI	-	Unresolved Item
WR	-	Work Request