U.S. NUCLEAR REGULATORY COMMISSION, REGION I

Docket/Report No: 50-443/89-13 License No.: NPF-67

Licensee: Public Service Company of New Hampshire
1000 Elm Street
Manchester, N.H. 03105

Facility: Seabrook Station, Unit No. 1, Seabrook, New Hampshire

Dates: October 11 - December 11, 1989

Inspectors: A. Cerne, Senior Resident Inspector
R. Fuhrmeister, Resident Inspector
S. Barr, Reactor Engineer
N. Dudley, Project Engineer
W. Lancaster, Physical Security Inspector
E. Sylvester, Senior Reactor Engineer
J. Yerokun, Reactor Engineer

Reviewer: N. Ervin, NRC Office of Nuclear Reactor Regulation

Approved By: Ebe C. McCabe, Jr. 1/6/90
Ebe C. McCabe, Chief, Reactor Projects Section 3B Date

Areas Inspected: Operational safety, ESF system walkdowns, reportable events, open items, the Containment Integrated Leak Rate Test, quality assurance activities, security, and design modification activities.

Results: Licensee planning, corrective measure implementation and overall response to potential problems with plant equipment (e.g., Westinghouse Technical Bulletin - section 3.5.4; Rosemount Part 21 Report - section 8.2) has been comprehensive and technically sound.

Two non-cited violations (sections 3.4 and 8.1) were identified by the licensee. Both procedural adherence and personnel errors were involved. Other examples where licensee action was required to correct procedure/personnel interaction problems are also discussed in this report (sections 3.5.2 and 8.3). Continued management emphasis upon associated interdepartmental coordination and monitoring of work is appropriate.

Successful performance of the Containment Integrated Leak Rate Test was witnessed. A recurrent problem with one leaking valve was identified, indicating that a repeat valve repair may not prevent recurrence (section 5). Routine involvement of Quality Assurance personnel in work and corrective action implementation, as well as in surveillances and audits, was evident.

A revision to the Seabrook Station Physical Security Plan is needed to resolve safeguards issues raised by an NRC security evaluation (section 9).

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DETAILS

1. Persons Contacted - New Hampshire Yankee (NHY)

E. Brown, President and Chief Executive Officer
J. DeLoach, Executive Director of Engineering and Licensing
B. Drawbridge, Executive Director of Nuclear Production
T. Feigenbaum, Senior Vice President and Chief Operating Officer
*J. Grillo, Operations Manager
R. Hanley, Operations Training Manager
T. Harpster, Director of Licensing Services
J. Hart, Licensing Manager
G. Kann, Program Support Manager
S. Kulback, Operations Security
*D. Moody, Station Manager
J. Peschel, Operational Programs Manager
*N. Pillsbury, Director of Quality Programs
C. Roberts, Manager, Security and Compensatory Systems
J. Vargas, Manager of Engineering
*J. Warnock, Nuclear Quality Manager

*Attended exit meeting conducted on December 12, 1989.

Other licensee and contractor personnel were also contacted.

2. Summary of Activities

2.1 Resident Inspector Activities

One senior resident inspector (SRI) was assigned to the site during the entire inspection period. On November 20, 1989, a new resident inspector was assigned to the Seabrook resident office.

Region-based inspectors reviewed technical issues and made routine site inspections, witnessed the Containment Integrated Leak Rate Test, and reviewed plant security. Regional inspector input to this report is documented in the report section appropriate to the inspection effort.

A total of 243 inspection hours, including 49 backshift hours and 18 deep backshift hours, were expended.

The SRI also participated in a meeting on October 11, 1989 at Seabrook Station between Region I management and the licensee to discuss Systematic Assessment of Licensee Performance (SALP) Report No. 50-443/87-99, covering the period from August 1, 1987 - June 30, 1989. Another meeting to discuss the licensee's schedule and action plan for open inspection issues was also held on site on October 11, 1989. This meeting was a prelude to a Region I/licensee meeting in King of Prussia, Pennsylvania on October 18, 1989 to discuss the NHY Corrective Action Plan status and the self-assessment program for the Unit 1 power ascension program. The SRI attended these meetings, as well as ones conducted by Region I and NRR personnel onsite on November 8, 1989 to review implementation of certain sections of the Seabrook Station Physical Security Plan and on November 20, 1989 to further discuss the licensee schedule for Corrective Action Plan and open item closure and readiness for testing. During November 13-20, 1989, the SRI participated in the Operational Readiness Assessment Team (ORAT) inspection of Seabrook Unit 1.

From October 23-27, 1989 while the SRI inspected another nuclear power station, a regional reactor engineer was assigned to Seabrook Station for routine coverage and safety system and equipment modification reviews. During the week of December 4, 1989, the SRI also attended training and a resident counterpart meeting in King of Prussia, Pennsylvania.

2.2 Visiting Inspector Activities

On October 12, 1989 an NRR Radiation Protection Branch reviewer visited the site to examine system modifications and documentation related to iodine effluent sampling, as discussed in the Safety Evaluation Report (SER) for Seabrook Station, confirmatory item no. 60.

On October 16-20, 1989, a regional inspector reviewed licensee response and corrective action to four open inspection items relating to the environmental qualification of Raychem splices. The results of this inspection will be documented in NRC Region I Inspection Report 50-443/89-14.

On November 6-10, 1989, two regional inspectors, supported by NRC contractor personnel, inspected the licensee's environmental qualification (EQ) program to address compliance with 10 CFR 50.49 and examine the EQ files. The results of this inspection will be documented in NRC Region I Inspection Report 50-443/89-17.

On November 13-20, 1989, an Operational Readiness Assessment Team (ORAT) inspected Seabrook Station to assess readiness for safe operation through reviews of operations and operational support programs to include health physics, maintenance, surveillance, engineering support, modification controls and Corrective Action Plan implementation. The results of this inspection are documented in NRC Region I Inspection Report 50-443/89-83.

On November 13-17, 1989, NRC regional and headquarters operator licensing (OL) examiners, assisted by an NRC contractor, administered written, oral and simulator examinations to twelve NHY operator license candidates. The results of these OL examinations are documented in NRC Region I Inspection Report 50-443/89-11.

On November 27 - December 1, 1989 regional inspectors and examiners, assisted by an NRC contractor, evaluated licensed operator proficiency at Seabrook Station by using NRC-developed scenarios to witness the performance of all shift operating crews on the Seabrook simulator. The results of this evaluation are documented in NRC Region I Inspection Report 50-443/89-15.

On November 27 - December 1, 1989, a regional inspector inspected the licensee program for environmental monitoring and liquid and gaseous waste handling and reviewed licensee actions on open inspection items. The results of this inspection are documented in NRC Region I Inspection Report 50-443/89-18.

On November 27 - December 7, 1989, regional inspectors, with the support of NRC contractor personnel, inspected the post-accident sampling system (PASS) and other inplant and effluent sampling systems and programs to check compliance with commitments made by the licensee in response to NUREG 0737. As part of this inspection, applicable TMI Action Plan items were reviewed and open items were closed, as appropriate. The results of this inspection will be documented in NRC Region I Inspection Report 50-443/89-19.

2.3 Plant Activities

The plant remained in operational mode 5, cold shutdown, with primary coolant temperature between 120F and 140F and the reactor coolant system vented at the top of the pressurizer. Maintenance and modification activities shifted from train 'B' to train 'A' equipment as the train 'B' residual heat removal system was returned to service. Major work was conducted on the electrical buses, the diesel generator support systems and the control building air, containment building spray, service water and primary component cooling water (PCCW) systems. Inspection, eddy current testing and repair activities related to tubing in the PCCW heat exchangers represented the major train-related outage work in progress on the primary side of the plant. The Containment Integrated leak Rate Test (CILRT) was conducted over a four-day period commencing on November 19, 1989.

3. Operational Safety

3.1 Plant Operations

The inspector observed plant operations during regular and backshift inspections of the control room and during routine tours of the plant. In the control room, plant logs, night orders, technical specification action statement status, and alarm conditions were reviewed, and operators were interviewed regarding control board indications and system lineups. Tagging controls and plant valve positions, used to support field work, were spot-checked and the Monthly Temporary Modification (TMOD) Report was reviewed to verify proper TMOD controls and tagging.

The inspector also verified that control room personnel were properly utilizing temporary pump requests for field situations requiring the installation of portable pumping equipment in plant sumps. Discussion with the radwaste and utilities (R&U) supervisor confirmed adequate control of the procedurally required temporary pump request forms. Additional discussions were held with the R&U supervisor concerning the control of Administrative Site Procedures (ASPs), fire barrier integrity, and containing the leakage of rain water into the plant. Outdated ASPs held over from site construction activities have been cancelled and a request for engineering services (RES 89-1054) has been issued to address the water leaks. Interim corrective actions for removing water as leakage occurs were assessed as acceptable.

The inspector compared control room log entries with technical specification action statement status sheets for two specific limiting conditions for operation (LCO 3.3.3.1, Containment Radiation Monitoring, and 3.7.6.B, Control Room Ventilation) for a one-month period. These LCOs are interrelated by common intake radiation monitoring which affects each LCO compliance and action statement differently. Thus, at any given time, either or both of the technical specification action statements may be entered depending upon the particular component failure. Exiting an action statement must therefore account for the other action statement's applicability. The inspector's review of eight action statement entries and seven exits during the sampled month revealed precise accountability and documentation by the control room operators. All questions raised by the log book review were satisfactorily answered by the action statement status sheets.

The inspector witnessed licensed operator personnel in the performance of watch-standing duties for the purpose of upgrading their inactive licenses to active status. Requalification training for licensed operators was discussed with training and operations management personnel and the station policy of removing from shift duties any operator who has failed requalification training was confirmed. In such situations, the inspector noted that the licensee program for remedial training and appropriate retesting is flexible to fit individual training needs and has been effectively used.

The inspector's witness of cold shutdown operations and review of work control activities within the control room identified no concerns. Operators were cognizant of overall plant and equipment status and performed board manipulations and system realignments in a controlled manner in accordance with procedural requirements. Operations management personnel were frequently observed in the control room, particularly during shift changes.

3.2 Plant Tours

The inspectors observed activities and plant status during general inspections of the plant. Work was examined for defects or noncompliances, and station staff and contractor personnel were interviewed in their work areas.

The inspector verified proper positioning, in accordance with operational procedures or work controls, of various valves, switches and breakers during system walk-downs and checked the valve and switch status in the control room. Similarly, temporary modifications and component tagging, maintenance work, and design change implementation activities, as observed during plant inspection tours, were evaluated for evidence of proper field controls and coordination of the work with the control room and operations personnel on shift. In certain cases, the operability of specific components and the applicability of the observed work to the technical specification requirements were discussed with the operators.

During several plant tours, the inspector checked general plant housekeeping, the control of temporary equipment and staging, the handling of tools and miscellaneous equipment within the radiologically controlled area (RCA), RCA access controls, and the compensatory measures in place for degraded security systems and fire barriers. Generally, good work practices were in evidence. For areas where work is in progress over several days, it is difficult to confirm small work item and tool controls until the job is finished. While a "roll back" out of certain plant areas is planned prior to plant heatup, increased attention to work controls during jobs in progress should be emphasized by station management.

During a tour of the Unit 1 tank farm, the inspector noted the existence of several floor drains within the diked area surrounding the refueling water storage tank. From a review of the piping and isometric drawings, it appeared that these drains were connected to the floor drains inside the diked area surrounding the reactor water makeup tank. That would bypass the RWST dike. Discussion with representatives from Engineering revealed that the two diked areas have separate drain systems with isolation valves which prevent uncontrolled draining. Cross-connecting of the floor drains is also precluded. The inspector had no further questions.

During a tour of the primary auxiliary building, the inspector noted ongoing activities involving eddy-current inspection of the tubes in the "A" primary component cooling water (PCCW) heat exchanger. The inspector noted the presence of broken off rolled ends of tube sleeves in the lower head of the heat exchanger. The inspector also examined several tube ends and sleeve ends, noting the advanced erosion evident on several. Notable by its absence was the corrosion, biofouling, and debris often associated with sea water cooling systems.

A tour of other plant areas and buildings resulted in specific observations as follows:

-- Cooling tower tour - verified access control (a guard was posted due to door problems) and posting, and material condition of equipment. No loose material which could become missles due to seismic activity was evident. The basin was filled.

-- Containment tour - housekeeping was good (no loose material lying about in spite of ongoing work). Containment sump screens were in-place and intact. Mesh barriers were being erected at accesses to areas which could become high radiation areas once the plant has operated at power.

-- Diesel generator building - portable catwalks secured, cranes/hoists secured, no equipment/debris lying about loose. An air-operated pump was used to circulate fuel oil through a filter. Oil soaked rags and filters were in plastic bags on the catwalk in the bay for the tank being cleaned ('B' tank).

With respect to all of the above area inspections, building tours and observations, no violations or unresolved safety concerns were identified.

3.3 Operating Procedures Review

On September 11, 1989, the licensee completed a review of all operating procedures for consistency. The review was conducted as part of a commitment documented in NRC Region I Inspection Report 50-443/87-10. As a result of the review, the licensee issued Operating Procedures OP 11.2, "Operating Procedures Writer's Guide," and OP 11.1, "Surveillance Test Procedure Writer's Guide," to establish a consistent format, style, and content for writing procedures. The inspector reviewed OP 11.1 and OP 11.2 and concluded that the procedures provided adequate detailed guidance for procedure writers. The inspector had no questions.

The inspector reviewed the new Operations Department Instruction ODI.21, "Direction for Inoperable Snubbers," which provides directions for dealing with inoperable snubbers as described in NRC Region I Inspection Report 50-443/89-08. The instruction requires an evaluation by the technical support group prior to removal of a snubber from service and the tracking of snubber removal under the action statement tracking system for snubbers covered under technical specification action statement 3/4.7.7, "Snubbers." A listing of snubbers by number and system location is available in the control room. The inspector concluded that ODI.21 provides an appropriate method for determining the operability of snubbers and provides adequate guidance to the Unit Shift Supervisor. The inspector had no questions.

3.4 Follow-up of Operating/Equipment Questions from Plant Heatup

During plant heatup for low power testing, several equipment failures occurred and were discussed in NRC Region I Inspection Report 50-443/89-80. Subsequent inspector follow-up was conducted to determine the cause of and corrective actions taken for each of the failures.

During heatup prior to initial criticality, residual heat removal cold leg injection valve RH-14 failed to open remotely. The valve was manually stroked without problem. Investigation determined that the motor pinion key had sheared. The motor pinion key was replaced on May 31, 1989, and the valve operability test was satisfactory. The pinion key was scheduled to be replaced after low power testing as a result of recommendations made in NRC Information Notice 88-84. The pinion key had not been replaced prior to low power testing because of the planned operability tests and the planned replacement of all keys during system outages after low power testing, and also because of the consideration of low decay heat levels during low power testing. All other similar pinion keys in safety-related motor-operated valves have since been replaced.

Residual heat removal (RHR) crossover valve RH-V21 would not open remotely. After being manually opened, the valve was successfully stroked from the main control room. Investigation determined the valve had stuck on its seat due to thermal binding. Operational steps to prevent future binding were being developed and the inspector has no further questions in this regard.

During initial operation of the reactor coolant pumps (RCPs) for heatup prior to initial criticality, a vibration alarm was received on RCP-B. Investigation of the vibration meters on all four RCPs determined that seven of the eight frame vibrator indicators were inoperable. Local vibration readings were taken on the pump shafts and motor frames and were within limits. Further troubleshooting identified that all eight probes had been wired incorrectly, seven in one configuration and the eighth in another. The licensee determined that the vibration monitors were most likely improperly wired during replacement and testing conducted after initial installation in October 1985. Post-maintenance testing involved only continuity tests and did not include functional or calibration tests. New calibration procedures have been written based on information obtained from the vendor, Bentley Nevada, and are to be incorporated into the 18-month functional checks for the indicator probes. The inspector had no further questions.

During heatup prior to initial criticality, an alarm received in the control room indicated low flow in loop 1 with the RCP running. Licensee investigation determined that the flow element was installed backward. Further investigation determined that the loop 2 flow element was also installed backward. All four flow elements had been removed and reinstalled in December 1988 to repair gasket leaks. The work requests for the flow elements in loops 1, 2, and 3 did not require verification of proper orientation of the flow element while the work request for the flow element in loop 4 required QA verification. Loop 1 and 2 flow elements were removed and properly reinstalled on June 3, 1989. The licensee performed a 100% quality assurance check of all flow elements, flow orifices and restricting orifices for instrumentation located in safety-related systems. The inspector reviewed the results of the quality checks and verified that all flow orifices were determined to be installed correctly. The licensee later added a check for proper orifice installation on the final inspection checklist for piping as part of maintenance procedure MS 0517.03, "Installation of Piping, Pipe Supports and STOW Supports." The inspector had no further questions.

The final equipment question raised during the readiness inspection for low power testing involved demineralizer three-way divert valve CS-TCV-129, which would not stay in the 'demin' position with the control switch in the 'auto' position. Investigation found that one lead in the control circuit was not terminated and that dynamic testing of the valve was not conducted. Continuity checks and relay operation of relay R1 contacts were conducted rather than the specific dynamic valve position verification due to the inability to establish required plant conditions for dynamic testing.

The licensee identified that this deviation from the required retest was not in accordance with maintenance instruction MT 3.1, section 4.1.23, and that the incomplete documentation of lifting the lead was a failure to follow the requirements of maintenance procedure MA 4.5. These two licensee-identified examples of failure to follow maintenance procedures violated regulatory requirements which require that procedures be properly implemented. The violation is not being cited because the criteria specified in 10 CFR 2, Appendix C Section V.G.1 of the Enforcement Policy were satisfied. The licensee identified the problem. Corrective actions for procedural compliance are being effected as part of the license response to Confirmatory Action Letter 89-11. A non-cited violation (NCV 89-13-01) documents identification of this issue, which concurrently is hereby closed.

On September 25, 1989, the Nuclear Quality Group issued Corrective Action Request 89-005 to express concern regarding seven station information reports which identified problems with post-maintenance testing. In response to the CAR, a committee was tasked with review of the reasons for the inadequate post-maintenance testing and with developing recommendations to improve the post-maintenance test program. The committee has not completed its review. The present post-maintenance testing program was reviewed by the Operational Readiness Team in NRC Region I Inspection Report 50-443/89-83 and found acceptable.

3.5 Operating Event Followup

3.5.1 Loss of RHR Shutdown Cooling Capability

On October 11, 1989, one of the two suction valves for the operable train 'A' residual heat removal (RHR) pump stroked close. Since the train 'B' RHR system was out of service for maintenance, the loss of train 'A' RHR suction flow resulted in the loss of all RHR cooling. This condition was corrected less than an hour later when the valve that was closed, RC-V-22, was manually reopened, the 'A' RHR pump was restarted and full RHR flow was reestablished. With negligible decay heat in the reactor core, reactor coolant system temperatures did not rise during this event. The licensee notified the NRC Headquarters Duty Officer via the Emergency Notification System (ENS) in accordance with 10 CFR 50.72. Licensee Event Report (LER) No. 89-012 was issued to evaluate the root cause, safety consequences and corrective actions.

Since valve RC-V-22 is energized from a train 'B' electrical bus, valve closure was traced to the reenergization of the train 'B' motor control center supplying power to RC-V-22. When the supply breaker for RC-V-22 was closed, the valve stroked closed because control power had not yet been reestablished for the valve. The valve performed as designed for the electrical power configuration at the time.

The root cause of this event was procedural. While ongoing maintenance activities and plant conditions required only partial restoration of train 'B' electrical power, the procedure used to restore power was written to provide for complete restoration of the AC bus. No consideration was given to the restoration of DC control power to RC-V-22 prior to motive power restoration. In this case, the actual electrical configuration for the work was not properly considered in restoration planning.

Complete licensee corrective action in response to this event will be reviewed as follow-up to LER 89-012, which remains open.

3.5.2 Primary Drain Tank (PDT) Collapse

On November 21, 1989, the 'A' Primary Drain Tank (BR5,TK-66A) was found in a partially collapsed and buckled condition. Station Information Report (SIR) 89-079 documented this discovery and an event evaluation team was established to determine the cause. The PDT is a non-safety-related tank located in the Waste Processing Building. Two tanks are located side by side and designed to service two nuclear units. With the 'A' tank collapsed, the 'B' tank remains available to support Unit 1 operation. Licensee evaluation of this event for reportability under 10 CFR 50 requirements made a determination of nonreportability.

The inspector reviewed the Event Evaluation for SIR 89-079, noting that the failure to provide vacuum protection, due to isolation of the nitrogen purge supply valves to the tank during tank pump down, was the cause of the tank collapse. During tank pump down, an auxiliary operator (AO) misinterpreted a gauge reading normal atmospheric pressure (i.e., approximately 15 psia) to represent 15 psig overpressure on the tank. Thus, the AO believed that the procedural precaution regarding positive tank pressure to be maintained was met. This mistake was compounded by the misaligned nitrogen purge valves and a procedure which should have stressed the importance of monitoring tank pressure during pump down (the tank is not constantly vented).

The inspector reviewed the licensee recommendations resulting from the event evaluation team review. An NRC Region I effluents specialist inspector also examined the tank, reviewed this event and discussed his follow-up in NRC Region I Inspection Report 50-443/89-18. The licensee's Event Reduction Committee also will be reviewing this event and is required to report its findings to the Nuclear Safety Audit and Review Committee (NSARC).

The inspector has no further questions on the collapse of the 'A' PDT. The licensee's evaluation of this event was thorough and the resulting recommendations were found technically correct and comprehensive.

3.5.3 Engineered Safety Features (ESF) Actuation

On November 29, 1989, a loss of train 'A' power for a few seconds caused the control room emergency filter fan to start and align the control building air system in the recirculation mode. This is considered an ESF actuation and was reported to the NRC Headquarters duty officer via the ENS in accordance with 10 CFR 50.72. Licensee evaluation of this event under 10 CFR 50.73 has scheduled LER 89-14 to be issued no later than December 29, 1989.

The inspector reviewed SIR 89-080 associated with this event. While all systems operated as required, the failure of battery charger EDE-BC-1A while restoring the train 'A' vital batteries from a cross-connected condition appears to require additional investigation and causal analysis. The ESF actuation was not caused by a valid signal and thus, while reportable, represents an electrical failure and interaction problem. Alignment of the station train 'A' vital battery buses in a cross-connected configuration is allowed by the station DC electrical design, with two 100% 125 volt batteries in each train. However, proper procedural control and implementation should allow restoration of each DC bus to its own battery supply without loss of vital equipment like a battery charger. Further NRC review will follow LER 89-14 issuance.

3.5.4 Westinghouse Technical Bulletin NSD-TB-89-06 Follow-up

On November 1, 1989, the Westinghouse Electric Corporation (W) issued a Technical Bulletin addressing the possibility of incorrect termi-point clip connections being installed in the solid state protection system (SSPS). A 100% visual inspection of the approximate 5200 termi-point clips in the SSPS, along with a sample of pull tests were recommended. The licensee implemented these recommendations and identified a pull test failure in the train 'B' SSPS, resulting in the requirement to implement a 100% pull test inspection.

The inspector witnessed a portion of the pull test inspections in SSPS control panel 1-MM-CP-13. Correct use of the applicable procedure, IS 89-1-1, and the use of calibrated tools were confirmed, as was the presence of knowledgeable quality control inspection personnel. The inspector interviewed the technicians responsible for the test and determined that the quality checks were being performed in accordance with the published acceptance criteria (reference: Operator's Quality Check Procedure for AMP TERMI-POINT Clip Application).

The inspector also discussed the results of the train 'B' inspection and the plans for the train 'A' SSPS inspection with the responsible system support manager. No inadequacies were found with the licensee response to W Technical Bulletin NSD-TB-89-06 and implementation of the recommended inspection program. There was appropriate QC involvement in the inspection process. Completion of the recommended inspection requirements for all safety-related termi-point clip installations is scheduled prior to plant heatup. Since the non-safety-related connections are not scheduled for inspection at this time, the inspector requested confirmation that visual inspection, in accordance with the W recommendation, would be performed. The licensee committed to conducting such inspection and tracking its accomplishment on the licensee's integrated commitment tracking system (ICTS), reference No. RE03104. Additionally, the licensee requested that W evaluate any delay of the non-safety connection inspections until after completion of the power ascension test program. By letter dated November 16, 1989, W responded that there was no need to conduct an immediate inspection of the non-safety-related termi-point clip installations.

The inspector had no further questions on the termi-point clip inspection and replacement work.

4. Engineered Safety Features (ESF) System Walkdown

The inspector walked down accessible portions of the Residual Heat Removal (RHR) system. At the time, RHR train 'A' was in operation in the hot leg recirculation mode and RHR train 'B' was in a system outage. The purpose of the walkdown of train 'A' was to check on conformance with the most recent valve lineup and to ensure the system was operating properly, while the walkdown of train 'B' was performed to check the progress of outage work, maintenance and modifications.

The inspector checked the ESF lineup of the RHR train 'A' system from the primary loop connections inside containment to the penetration area and RHR equipment vault outside the containment. To verify proper valve lineup, the inspector utilized the licensee's operations form OS 1013.03A, "RHR System Lineup," and drawing 9763-F-805808, "RHR System Piping and Instrumentation Drawing." The inspector found two valves out of position per OS1013.03A; however, both discrepancies had been previously identified by the licensee and were being acceptably controlled and tracked with form OP10.3B, "System Lineup Review and Exception Sheet." In addition to the system lineup, the inspector reviewed the overall material condition of the system. The inspector noted that system component and area housekeeping was adequate, components were properly labeled, instrument calibration was up-to-date, and mechanical snubbers were properly aligned and attached. The one major discrepancy in system material condition was valve RH-V-8, the RH-P-8A pump discharge sample valve. The valve was found to be leaking, but the licensee had positive control of the situation. Radiological control barriers had been established and all leakage was being collected in a funnel and directed to a floor drain. Subsequent to the walkdown, the inspector reviewed a Request for Engineering Services (RES) that had been submitted by the licensee RHR System Engineer concerning RH-V-8 and other similar valves in the RHR system. The RES requested that all gate-type vent and drain valves be replaced with globe valves due to the extensive maintenance required for the gate valves. Based on the inspection of RHR train 'A' and in light of the proper documentation for all noted discrepancies, the inspector determined that the system was being effectively maintained and was capable of performing all required ESF functions.

Following the inspection of RHR train 'A', the inspector walked down the RHR 'B' train accompanied by the licensee RHR System Engineer. The purpose of this walkdown was to inspect the modifications made to train 'B' during the system outage. The same modifications had been made to train 'A' during its previous outage. One design change inspected was the addition of a check valve in series with each of two existing check valves that provide isolation of RHR train 'B' from the Containment Building Spray system. This change represents a confirmatory item in the Seabrook Safety Evaluation Report, Supplement No. 8, documenting the licensee commitment to add the additional check valves.

Other modifications inspected were the substitution of a globe valve in place of a gate valve for the RHR pump flow control valve and the correction of a problem relating to pump vibration for the RHR pump impeller. Modification work was found to have been performed effectively and in a controlled manner. No discrepancies were identified. Also inspected during the train 'B' walkdown was the system material condition. With the exception of some piping insulation awaiting installation, the material condition of train 'B' was acceptable and the system appeared ready to be returned to service.

5. Containment Integrated Leakage Rate Test

From November 19 to November 22, 1989, the licensee conducted the containment Integrated Leakage Rate Test (CILRT) for the Unit 1 Containment as required by 10 CFR 50, Appendix J. The test was performed in accordance with station procedure number EX 1803.001, Revision 01, "Reactor Containment Integrated Leak Rate Test - Type A". The test was observed by a region-based inspector and a resident inspector. The inspectors reviewed the test procedure, witnessed preparations for test, and observed various portions of the test. Other documents reviewed include the CILRT test log, instrument calibration records, piping and instrument drawings and test results.

Pre-Test Setup

The inspector verified, on a sampling basis, the positioning of valves identified in station procedure EX 1803.001, Rev. 01. A drain valve, 1-FP-V-0922, at containment penetration X-38 was found not to be closed, which is the required test position. This valve also had 2 test tags on it instead of 1. When informed of this situation, the licensee investigated the cause of the discrepancy and then properly aligned and tagged the valve for the test. Other penetrations walked down were found to be in the required configuration.

The inspector reviewed and found acceptable the results of station procedure EX 1803.004, Rev. 00, "Containment and Containment Enclosure Surface Inspection," which was used to perform the inspection of the containment internal and external surfaces in accordance with 10 CFR 50 Appendix J (V.A.).

Instrumentation

The inspector reviewed the calibration records for the resistance temperature detectors (RTDs), dew cells, pressure detectors and mass flowmeters used for the test. The instruments' calibrations met the accuracy and time requirements of ANSI/ANS 56.8-1987 and were traceable to the National Bureau of Standards. A total of 26 RTDs, 6 dew cells (with 6 back-ups), 2 pressure detectors and 1 mass flowmeter (with 1 backup) were used for the test.

The test data collection and analysis were as follows:

-- The two pressure detectors indicated the containment pressure on the Data Logger at the test center.

-- The 26 RTDs provided input into the data logger and the temperature reading of each RTD could be selected.

-- The dew cells (and backups if selected) provided input into the data logger through 2 "phys-chem" monitors.

-- The data logger transmitted all data to the CILRT test computer at the test center.

-- The computer continually monitored instrument readings, and analyzed and printed test data and calculations every 20 minutes.

No unacceptable conditions were identified.

CILRT Chronology

11/19/89	1800	ILRT measurement system fully operable and ready.
11/20/89	0130	Began containment pressurization.
	1830	Test pressure reached, test boundary isolated from compressors (51 psig).
	1843	Began stabilization period.
	2343	Temperature stabilization criteria met.
	2343	Began ILRT (50.39 psig).
11/21/89	0625	Test terminated because of valve leakage.
	0643	Test restarted.
11/22/89	0643	ILRT ended (24 hour duration).
	0823	Stand. verification flow test. Imposed flowrate of 12.22 scfm (0.15%/day).
	1223	Verification flow completed.
	1223	Test completed.
	1829	Start depressurization.
11/22/89	0845	Exit interview held.
11/23/89	1514	Containment depressurized.

Test Performance and Control

Tours were made by the inspector before and during the CILRT to ensure that test activities were being conducted in accordance with the test procedure and within regulatory requirements. Test boundaries were surveyed for evidence of leakage and proper valve positions. The inspector observed that the licensee's quality control group was monitoring the test and keeping abreast of situations.

During a walkdown of test boundaries with test personnel, a major leak was identified at penetration X-36 through vent valve RMW-V-94. This leak was determined to be coming through containment isolation valve RMW-V-30. The licensee evaluated the leak and elected to terminate the test, isolate the leak, and re-start the test. The inspector verified that this was accomplished within the scope of the station's procedure. The inspector independently examined the penetration area and then reviewed the last Local Leak Rate Test results of the leaking containment isolation valve (RMW-V-30). (See Findings paragraph below.)

CILRT Results

The containment successfully passed the "As-left" Integrated Leak Rate Test, demonstrating containment acceptability for power operation. The calculated leak rate using the "Mass Point Analysis" method was 0.0545 wt %/day (0.75 La is 0.1125 wt %/day). The "As Found" leak rate was indeterminate as described below.

Findings

The containment leak rate met the acceptance criteria for power operation in the "As-left" condition. The "As-found" condition is still indeterminate because of a need to add in subsequent LLRT data for RMW-V-30. The implications of these results were discussed with the licensee and the inspector confirmed that they were understood by the licensee. The test was performed within the guidelines of the procedure. All test personnel interviewed were knowledgeable and competent to perform their duties. The licensee's quality control organization monitored on-going testing. A review of the previous Type C test results of containment isolation valve RMW-V-30 showed "As-found" leakage as "undetermined" and "As-left" leakage of 5.54 scfh (after repairs). Since the problems with leakage of valve RMW-V-30 appear to be recurrent and have not been corrected by prior repairs, a root cause evaluation and determination of proper corrective action, beyond another valve repair, are warranted to ensure effective resolution. "As-found" leakage implications will be further assessed during routine review of the CILRT report.

6. Installation and Testing of Design Modifications

The inspector reviewed the documentation for and observed portions of the installation and testing of design coordination request (DCR) 86-481. This design change provides a high speed, automatic, static transfer switch between inverters UPS-I-1E and 1F and their respective maintenance supplies. The switch allows for uninterruptible transfer of power to vital instrument buses 1E and 1F, from inverter to maintenance supply and vice versa.

The uninterruptible power supplies (UPS) for buses 1E and 1F are the normal sources of power to the distribution panels that make up each bus. Each UPS unit consists of two major components: an AC-to-DC rectifier type power supply that converts 480 VAC power to 125 VDC and a DC-to-AC inverter that changes the 125 VDC to 120 VAC. On a loss of the 480 VAC supply or a failure of the rectifier, backup 125 VDC power is supplied to the inverter by the vital DC distribution system. If the UPS is not operational or malfunctions, the static transfer switch was to be installed to provide an alternate source of 120 VAC power. This power is supplied by a motor control center powered from the same emergency bus as the UPS, through a stepdown transformer and the static transfer switch to the power panel. The switch automatically selects between the inverter output or the alternate power source, whichever is most reliable. Once shifted to the alternate power source, the switch will automatically shift back to the inverter output when the UPS is functioning properly. The transfer switch can also be controlled manually using control pushbuttons located on the switch.

Prior to inspecting the installation, the inspector reviewed the documentation in the DCR package. This included the technical requirements and specifications for the UPS from the vendor, the Elgar Corporation, the licensee's engineering evaluation, the DCR implementation plan, and the DCR functional test requirements. Also reviewed as part of the DCR package was the 10 CFR 50.59 safety evaluation. DCR documentation was extensive and complete. The installation and test procedures were clear and thorough in their precautions and directions.

The installation of the static transfer switch involved mounting the switch, running additional conduit and cable from the vital instrument power panel to the transfer switch, and from the switch to the inverter, and UPS internal wiring modifications. The modifications were all contained within the essential switchgear room. Over a four day period, the inspector observed the completion of the UPS-I-1F static transfer switch installation and portions of the functional testing of the switch. The inspector noted that, during the installation and testing, the licensee maintained an adequate staff in the switchgear room to accomplish all work in a safe manner. As a minimum, an electrician, a work group supervisor, the system engineer and a quality control supervisor were present. The inspector inspected the modifications made to the 1F vital instrument power panel and to the 1F UPS cabinet and was satisfied that all work had been performed in an acceptable manner.

The testing portion of the DCR was intended to demonstrate operability of both the UPS and the newly installed transfer switch by a performance test. The test included loaded transfers of the static switch and UPS, as well as the placement of intentional grounds on the 480 VAC bus and the 125 VDC bus feeding the UPS. The placement of the grounds verified that the static switch/UPS output was not interrupted as a result of grounding. Through direct observation of the testing, the inspector determined that the tests were conducted in a controlled and safe manner. Proper barriers were placed around the work area and access to the switch gear room was controlled. Communications were established with the control room, and the DCR test procedures were rigorously followed. At one point during the testing, the system engineer had a question concerning a procedure step. After discussing the matter with the shift superintendent, the conservative decision was made to convene a Station Operation Review Committee (SORC) to resolve the question rather than take the chance of changing or violating the procedure.

The inspector identified no inadequacies in the licensee implementation of this DCR for UPS-I-1F. DCR implementation for UPS-I-1E is scheduled to be performed in conjunction with the required 'A' train electrical system outage.

7. Quality Assurance/Corrective Action Activities

7.1 Low Power Test Program Audit

As discussed in NRC Region I Inspection Report 50-443/88-12, inspectors noted that the licensee QA department had not formulated any plans for providing a level II oversight review of the facility's proposed startup test program. As a result of this NRC concern, the licensee committed to performing a test surveillance program during low power tests. NHY QA Audit Report No. 89-A-05-OS, "Low Power Test Program," dated August 15, 1989, summarizes the results of an audit designed to evaluate the licensee's compliance and implementation of the Low Power Testing Program.

The inspector reviewed the QA audit report. The report fulfills the commitment made by the licensee documented in Inspection Report 50-443/88-12. The audit provided broad coverage including review of control room activities and administrative controls associated with mode changes, housekeeping, chemistry, health physics and security. The multidisciplined team conducted the audits over a two month period and identified no deficiencies. However, the audit report did provide recommendations to enhance program performance. The inspector concluded that an adequate audit of the Low Power Test Program was conducted.

7.2 Corrective Action Plan Review

Item 1.C-1: revise policy on control room access to establish the maximum number of personnel allowed in the control room and the horseshoe area of the control room.

Operations Management Manual (OPMM) Revision 18 included changes to Chapter 3, Shift Operations, regarding control room manning and access. Subsection 1.F, Watch Station Conduct, has been revised to indicate that additional operators may be assigned to perform specific functions during complex evolutions. It further specifies that each operator be informed of the presence of additional personnel and be made aware of their function and limits. The revision also requires that access be limited to persons with official business or management authorized activities.

The authority and responsibility for controlling access is assigned to the control room commander (defined elsewhere in the OPMM). Examples of persons with official business in the control room are given. Additionally, requirements on Special Testing Activities and termination of those activities, along with provisions for handling observers and visitors, are specified. Specific numerical limits for observers and visitors have been established. These numbers may only be exceeded with written authorization of the Operations Manager, who will specify by name personnel permitted access as observers and visitors for a specific activity. Authority and responsibility for controlling access to the horseshoe or "sacred" area is assigned to the senior on-shift operator. The inspector reviewed Revision 23 to the OPMM, dated November 10, 1989 and confirmed that the requirements have been carried over in subsequent revisions.

2.A-6: review the event evaluation procedure to determine if enhancements are required concerning the post-trip review, assignment of personnel, post-trip critiques and written chronologies.

The inspector reviewed Revision 2 to New Hampshire Yankee Procedure 12830, Event Evaluation and Reduction Program. The procedure has been strengthened. It now clearly states, as a requirement, that personnel are to receive training in the evaluation program prior to being called upon to perform an evaluation. The most significant improvement is the requirement to perform a critique for any event on site. This critique is to be conducted with all personnel who participated in or witnessed the event. This critique is to be conducted prior to releasing personnel from the site. The critique includes written descriptions of the event by all involved personnel and the generation of a synopsis and chronology by the Event Team Leader. This will ensure that the information is gathered and collated while it is still fresh in the minds of the participants.

Based upon the licensee's implementation of actions to address the control room access/work control and event evaluation concerns raised in Correction Action Plan items 1.C-1 and 2.A-6, no additional NRC inspection effort of this issue is required. Routine inspection of control room activities and the event analysis and evaluation process in the future will monitor the effectiveness of these corrective measures.

8. Follow-up of Licensee Reports and Open Items

8.1 Licensee Event Reports (LERs)

(Closed) LER No. 89-009, Technical Specification Surveillance Not Properly Performed and LER No. 89-013, Noncompliance with Technical Specification Action Requirements. Both of these LERs involved a violation of technical specification action statements caused by separate personnel errors. In the first case, a chemistry technician incorrectly performed the analysis of an effluent sample taken from the primary component cooling water (PCCW) head tank. Since the PCCW head tank rate of change alarm was out of service, sampling was required every twelve hours by a technical specification 3.3.3.9 action statement. Correctly analyzed samples taken before and after the subject sample indicated no actual activity problems, but the time duration between these valid samples exceeded the allowable technical specification duration. Hence, the violation was reported as a licensee event under 10 CFR 50.73.

In the second case, a portable monitor, installed to meet the action statement of technical specification 3.3.3.1 with the containment post-LOCA monitor out of service, was mistakenly unplugged for approximately five hours. The HP technician who unplugged the monitor to use the electrical receptacle for another purpose was not familiar with the technical specification requirements or aware of the consequences of unplugging the portable monitor.

In both cases, the technicians involved were counseled, additional training was conducted within the departments, and procedures were reviewed to ensure accuracy and clarity of directions provided to the technicians performing the work. A caution as to the consequences of unplugging energized equipment within the plant was also discussed in a station newsletter disseminated throughout the site and caution tag usage for electrical power cords was incorporated into health physics procedures for portable equipment.

The inspector reviewed the LERs and the licensee corrective action and determined that the discretionary criteria of 10 CFR 2, Appendix C, section V.G.1 have been satisfied. Based upon licensee identification, reporting and initiation of comprehensive corrective measures with respect to both of these examples of noncompliance with technical specification requirements and also in consideration of the minimal safety significance of the actual events, these violations are not being cited. Non-cited violation number 89-13-02 documents identification of this issue, which is hereby closed.

8.2 10 CFR 21 Report

(Closed) 10 CFR Part 21 Report No. 89-00-01: Potential Failure of Rosemount Transmitters. As discussed in NRC Region I Inspection Report 50-443/89-01, a potential defect involving the loss of oil in the transmitter sensing module was identified by Rosemount, Inc., for certain transmitters manufactured prior to July, 1989. The licensee's review has found 61 of the subject Rosemount Model 1153 and 1154 transmitters installed at Seabrook.

Since the problem with potential oil loss occurs slowly over time, the licensee's corrective action plan includes a special calibration program, transmitter performance trending, and replacement of the pressurizer pressure transmitters and any spare Rosemount transmitters in stock on a schedule which is consistent with the support of station activities. The inspector verified that all the subject transmitters had been or were being calibrated in a manner which would check for any degradation due to oil loss. The inspector also reviewed the Rosemount 10 CFR 21 notification, dated February 7, 1989, and evaluated the licensee's plan for addressing the stated concerns, based upon Rosemount's discussion of how the transmitters would exhibit reduced performance. It was also noted that testing by Rosemount, Inc. was conducted to determine limits in the performance degradation and methods in the detection of affected transmitters. The inspector confirmed that the licensee has reviewed and evaluated all of the latest relevant Technical Bulletin and report information from Rosemount, Inc., on this potential problem.

The inspector determined that licensee response and corrective action planning for this Rosemount Part 21 report to be both timely and comprehensive. Given the slowly developing nature of the potential problem, the licensee's monitoring program was assessed as adequate. Quarterly channel checks, overrange tests and normal calibrations of the subject transmitters should indicate performance degradation prior to component failure. Special calibrations, recently accomplished, provide adequate indication of transmitter acceptability and a baseline for future performance. The inspector considers licensee measures to address this vendor identified problem to be extensive and conducive to the identification of any actual hardware problems in the future.

10 CFR 21 Report No. 89-00-01 is closed.

8.3 Licensee Action on Previously Identified Items

(Closed) Unresolved item 89-08-01: Unmonitored Release from the Turbine Building Sump. The inspector reviewed the licensee analysis of technical specification action statement requirements relative to Station Information Report SIR 89-042. The specific incident involving bypass of the turbine building sump radiation monitor was evaluated from both design basis and control adequacy standpoints. While it was determined that the turbine building sump was not intended to be dedicated solely to processing radioactive effluents, the program used to control temporary sump pump usage and coordinate action statement status requirements with control room operators required improvement. A procedure for the installation of temporary pumps was issued on October 5, 1989 to delineate the necessary administrative controls and coordination requirements. The use of Temporary Pump Request forms was formalized.

The inspector reviewed station operating procedure UN0599.047 governing temporary pump controls and checked other operating procedures affected by its issuance. Temporary Pump Requests were spot-checked, both in-process in the control room and in their final documented closeout format. Technical specification action statement coordination and clearance were noted to be properly controlled for the times the temporary turbine building sump pump was installed. The inspector also determined that the program of controls established by the licensee to address the original problem was broad enough in scope to adequately cover all temporary pump usage within the protected area.

Licensee controls in this area have been strengthened and procedural compliance with the new program of controls was checked by the inspector. The inspector identified no concerns with the licensee's current program for installing temporary pumps within the station and no specific problems were found with the use of the temporary turbine building sump pump. This unresolved item is closed.

(Closed) Unresolved item 89-09-03: Failure to Perform Technical Specification Surveillances. The inspector reviewed the licensee's reportability determination for SIR 89-061, in which it was documented that certain radioactive liquid effluent and gaseous effluent monitoring instrumentation surveillances had not been performed in the time intervals required by the technical specifications. Although repetitive task sheets (RTS) had been issued to conduct monthly source checks of the subject radiation monitors, these surveillance activities are redundant to the automatic source check accomplished by the monitors on a daily basis. This daily source check is logged into the plant computer and an alarm would be generated if the check were not completed.

The inspector discussed the automatic source check feature of the radiation monitors with licensee personnel, verifying that failure of the check would alarm similar to a monitor failure. In fact, the monthly RTS work requirements actually use the daily source check feature in the performance of the technical specification surveillance activities. The inspector also spot-checked the computer logging history for certain radiation monitors to confirm evidence and documentation of daily instrument source checks.

Based upon the fact that the internal source check design feature of the radiation monitors provides compliance with surveillance requirements, the licensee's failure to complete the RTS activities represents neither a technical specification noncompliance nor a reportable event. This issue is therefore resolved and closed.

However, as discussed in section 8.1 of this inspection report, a non-cited violation resulted from personnel errors leading to noncompliances with technical specification action requirements. While no noncompliance resulted from the failure to perform the radiation monitor RTS surveillance discussed in this section, the cause of the failure to perform a scheduled RTS activity should be analyzed by the licensee in the same vein as the personnel errors resulting in the non-cited violation.

9. Physical Security Plan Implementation and Controls

Protected Area Barrier

On November 7, 1989, NRC on-site review of the protected area barrier (PAB) identified a need to upgrade the PAB between Unit 1 and Unit 2 to meet the criteria for a permanent PAB for Unit 1. Existing compensatory measures were found adequate. On November 8, 1989, the following exceptions relative to NRC criteria for a PAB were identified to the licensee.

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Following a discussion of the above concerns, the licensee committed to submit, within 10 working days, a schedule for completing an engineering study to resolve the concerns, and a revision to the Plan to update the Plan and incorporate additional compensatory measures. The licensee also committed to provide a schedule for implementation of the separation barrier upgrades upon completion of the engineering study. The engineering study would also investigate the possible existence of additional separation barrier weaknesses, other than those discussed above, and address their resolution.

10. Management Meetings

At periodic intervals during the course of this inspection, meetings were held with licensee personnel to discuss the scope and findings of this inspection. An exit meeting was conducted on December 12, 1989, to discuss the inspection findings during the period. During this inspection, the NRC inspector received no comments from the licensee that any of their inspection items or issues contained proprietary information. No written material was provided to the licensee during this inspection.