U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Number:	92-24
Docket No.:	50-443
License No.:	NPF-86
Licensee:	North Atlantic Energy Service Corporation Post Office Box 300 Seabrook, New Hampshire 03874
Facility:	Seabrook Station
Dates:	December 22, 1992 - January 25, 1993
Inspector:	Noel Dudley, Senior Resident Inspector Richard Laura, Resident Inspector Fred Paulitz, Electrical Engineer

Approved By: John F Rogge 2-4-93
John F. Rogge, Chief Date
Reactor Projects Section 4B

OVERVIEW

Operations: Operators responded safely to two reactor trips. Fire protection procedures were weak in providing guidance for controlling combustible fire permits. The completion of the five year plant labeling program should result in appropriate labeling of equipment room doors.

Radiological Controls: Health physics department performance was good.

Maintenance/Surveillance: The maintenance department safely completed the major emergent task of replacing a service water pump.

Emergency Preparedness: The transition of emergency response responsibility to Massachusetts organizations indicated good performance.

Security: Security personnel performed routine activities in a meticulous manner and exhibited a proactive approach in maintaining security equipment.

Engineering/Technical Support: The troubleshooting process to identify and correct the cause of the generator electrical ground which caused a reactor trip was well managed. Technical support engineers' efforts to determine the root cause of testing failures of General Electric HEA relays at 70% rated voltage were good. North Atlantic has adequately addressed the concerns of the adverse effect of high environmental temperatures in the pipe chases on the qualified life time of the main steam and main feedwater isolation valves.

Safety Assessment/Quality Verification: North Atlantic's process that identifies performance trends was effective.

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DETAILS

1.0 INSPECTION SCOPE

1.1 NRC Activities

Two resident inspectors and one electrical inspector were assigned throughout the period. The inspectors conducted backshift inspections on January 12 and 20, and deep backshift inspections on January 3, 10, 15, 16, 17, 18, and 24.

1.2 Plant Activities

At the beginning of the period, the reactor was operating at full power. On January 3, operators manually tripped the reactor due to a loss of feedwater flow. The operators brought the reactor critical on January 4 and reached 100% power on January 6.

On January 14, an automatic reactor trip occurred due to the actuation of the generator fault protection circuitry. The operators brought the reactor critical on January 20, and reached 100% power on January 21.

2.0 OPERATIONS (71707, 92701, 93702)

2.1 Routine Plant Operations

The inspector conducted daily control room tours, observed shift turnovers, attended the morning station manager's meeting, and monitored plan-of-the-day meetings. The inspector reviewed plant staffing, safety system valve lineups, and compliance with technical specification requirements. The inspector conducted tours in the primary auxiliary building, the emergency diesel generator rooms, the residual heat removal vaults, the turbine building, the condensate storage tank building, and the circulating water pumphouse. During the tours and attendance at the various meetings, the inspector noted overall good performance by the operations staff.

On January 3, operators manually tripped the reactor due to a loss of feedwater flow. The details and NRC assessment of this event are documented in NRC special safety inspection report No. 50-443/93-01.

On January 14, the operators responded to an automatic reactor trip caused by a generator ground fault. The inspector verified that the operators had stabilized plant conditions following the trip.

Based on industry events involving undetected loss of annunciators, the inspector reviewed the main control room annunciator systems. The annunciator systems consist of a video alarm system (VAS) and six hard wired annunciator panels. The VAS is driven by the main plant computer and the loss of portions of the computer system are alarmed on the VAS.

The loss of the main computer is annunciated on a hardwired annunciator panel. The hard wired annunciators are powered directly from non-vital a.c. or d.c. power panels. A separate loss of power alarm exists for each hardwired panel and is powered from a vital 120 volt a.c. power supply. The inspector reviewed the procedures for loss of annunciator systems. Each of the VAS alarms had a corresponding alarm response procedure that could be displayed on a video screen. Each alarm window on a hardwired annunciator panel had a corresponding alarm response procedure. The procedures directed the operators to the associated power supplies for the panel and provided logic diagrams of the power supplies. The alarm response procedure for the loss of the main plant computer provided directions for what additional surveillance was required to compensate for the loss of the computer. The inspector determined that the annunciator system was not vulnerable to an undetected loss of power and that adequate procedures existed for responding to a loss of power to the systems.

During a plant tour, the inspector noticed that doors leading into equipment rooms were labeled with door numbers and other identification but were not labeled to identify the equipment in the room. Workers had used magic markers and pencils to designate class 1E battery, residual heat removal, safety injection, and containment spray room doors. The inspector reviewed North Atlantic's administrative procedure SM 7.2, "Station Labeling Program," dated June 8, 1992, and an internal memorandum, and held discussions with the operations engineer responsible for the labeling program. The labeling program is extensive, labeling room or area entrances with an equipment location map that delineates the major pieces of equipment located in the room. North Atlantic's five year labeling program was scheduled to be completed in 1996. The inspector concluded that completion of the labeling program should result in appropriate labeling of equipment room doors.

2.2 Fire Protection

On January 5, 1993, the inspector observed that two combustible fire permits located in the fuel building had expired on December 31, 1992. The inspector interviewed the fire fighting personnel responsible for implementing administrative requirements in the "Station Fire Protection Manual." The fire fighters maintained a log of all combustible material permits and had prepared two new permits, C 30001 and C 30002, for the fuel building. Permit number C 30001 was signed on January 5, 1993, and posted by January 12, 1993. Permit number C 30002 was signed on January 7, 1993, but was not posted until after January 12, 1993. An expired permit number, C 10086, was attached to a wooden box containing control rod drive mechanism unlatching tools. The work supervisor never signed this permit and the expiration dates were changed by lining through the old date and adding a new date. The expiration dates have been changed every six months since November 5, 1991. The inspector reviewed procedure FP 2.2, Rev. 1, "Control of Combustible Materials," and determined that there was no guidance for controlling combustible material permits.

The fire fighter supervisor stated that procedure FP 2.2 would be revised to clarify the requirements for signing fire permits, to define the requirements for renewing fire permits, and to establish a formal process for updating fire permits. The inspector concluded that the

lack of guidance for controlling combustible material permits was an administrative weakness that was being addressed by the fire fighter supervisor.

2.3 Cooling Tower Fans in Pull-to-Lock: Violation 92-80-01 (Closed)

In order to prevent damage to the mechanical draft cooling tower fans due to automatic starts in icy conditions, the operations department had operated the fan control switches in pull-to-lock since December 8, 1988. During an NRC team inspection, the NRC noted that this practice violated Technical Specification 3.7.5.b which required the fans to automatically start on a tower actuation signal. North Atlantic immediately placed the cooling tower switches in the automatic position and subsequently implemented contingency procedures to preclude ice or snow damage during automatic fan starts.

The inspector reviewed North Atlantic's letter (NYN-92148) issued on October 30, 1992, written in response to the violation. North Atlantic determined that the root cause for the violation was the performance of an inadequate review by North Atlantic personnel in the development and certification of the Seabrook Station Technical Specifications. The licensing department cancelled technical clarification TS-070 that supported leaving control switches in the pull-to-lock position. The inspector noted that licensing engineers performed an inadequate evaluation of the associated license requirements when they issued technical clarification TS-070.

North Atlantic requested a license amendment to Technical Specification 3.7.5 in a letter (NYN-92127) dated September 4, 1992. The NRC issued Technical Specification Amendment No.18 on November 27, 1992. The amendment removed the automatic fan actuation as a technical specification surveillance requirement and modified Technical Specifications 3.7.5 to explicitly define fan operability as the capability of the fan to be manually started from the main control board.

The inspector verified that the switches to the cooling tower fans had remained in the normal position until the NRC issued Amendment No. 18. The inspector noted that prior to the issuance of the violation, sufficient engineering analysis had been completed to provide a basis for operating the fan switches in the pull-to-lock position. The inspector concluded that Amendment No. 18 resolved the issue of cooling tower fan operability. This violation is closed.

3.0 RADIOLOGICAL CONTROLS (71707)

During routine tours of the plant, the inspector observed proper radiological controls implemented for personnel entering, exiting, and working in the radiological controlled area (RCA). Health physics (HP) technicians properly updated the radiation and contamination survey maps at the health physics (HP) control point, on a weekly basis. The HP technician stationed at the RCA control point closely monitored personnel entering and exiting the RCA to ensure personnel had the required dosimetry and properly used the automatic

contamination checking equipment. The inspector verified proper posting of radiation and contaminated areas, calibration of radiological monitoring equipment, and the locking of high radiation area doors. In summary, the inspector noted good performance in the area of radiation protection.

4.0 MAINTENANCE/SURVEILLANCE (61726, 62703)

The inspector observed the repair of a leaking safety injection pump discharge flow transmitter test valve, SI-V76. Boric acid residue had indicated leakage where the valve stem threaded into the test block assembly. Instrument and control (I&C) technicians performed the work per work request 93W000040. The technicians isolated the discharge flow transmitter in accordance with the routine surveillance procedure, RTS10562301. They tightened the valve stem assembly approximately one flat and successfully performed a leak check of the mechanical joint using a calibration pressure pump to pressurize the joint to system operating pressure. The inspector assessed that the technicians properly performed this safety related maintenance and retest. The repair was an example of North Atlantic personnel's sensitivity to the identification and repair of small mechanical joint leakage.

The inspector observed portions of the replacement of the 'C' service water pump. Mechanics replaced the centrifugal two-stage vertical deep draft pump due to unacceptable vibration levels. The pump shaft is approximately 60 feet long and water is pumped up through a pump column that contains bearings to support the shaft. To identify the cause of the high vibration levels, mechanics uncoupled the motor from the pump shaft. The motor ran unloaded with minimal vibration, which indicated a pump problem. The mechanics, working with crane operators, divers, electricians, security officers, and operators removed the 60-foot pump column and the 'C' service water pump. The mechanics installed a rebuilt pump and pump column. Electricians reinstalled the pump motor and the mechanics coupled the pump shaft to the motor. After completing the maintenance, operators ran the new pump to verify the vendor head curve information. The new pump exhibited acceptable vibration levels, flow rates, and pressures. The licensee initiated a root cause evaluation to determine the reason for the high vibration levels. Mechanics had replaced the 'C' service water pump during the previous outage as a routine preventive maintenance item.

The inspector noted that the emergent task of the pump replacement was a complex job requiring multiple departmental interfaces. The inspector determined that maintenance management and supervisory oversight were focused and effective. The inspector concluded that North Atlantic performed the major maintenance activity safely.

5.0 EMERGENCY PREPAREDNESS (71707)

On December 30, the Massachusetts Emergency Management Agency (MEMA) accepted the responsibility for implementing the Massachusetts Radiological Emergency Response Plan (MARERP). The Federal Emergency Management Agency had reviewed and approved the MARERP. On an interim basis, the Seabrook Station Offsite Response Organization (ORO)

agreed to provide assistance, as needed, to Massachusetts emergency organizations in the event of a Seabrook Station emergency. The inspector assessed that the turnover indicated good performance.

6.0 SECURITY (71707)

The inspector observed various routine security activities. The inspector noted that a guard stationed in the secondary alarm station (SAS) was alert and knowledgeable of ongoing security activities. Security personnel properly performed routine protected area zone checks and building operability checks. Security guards posted at the service water intake and discharge buildings were alert and aware of their responsibilities. Due to the identification of one cracked 12 volt battery located inside a terminal transmission panel (TTP), instrument and control technicians (I&C) inspected the other TTP batteries. The I&C technicians found other cracked batteries and replaced all of the TTP batteries. The TTP battery routine surveillance was enhanced to require the change out of the batteries on a periodic basis. The inspector determined that security personnel performed routine activities in a meticulous manner and exhibited a proactive approach in maintaining security equipment.

7.0 ENGINEERING/TECHNICAL SUPPORT (71707, 37055)

7.1 Reactor Trip - Ground Fault

On January 14, with the facility operating at 100% power, the reactor tripped due to a turbine trip. The turbine trip resulted from the generator protective circuits responding to a ground fault condition. The inspector reviewed the post trip review activities, attended planning meetings, and observed troubleshooting activities.

Technical support engineers and electricians inspected the electrical bus bars between the generator and the generator step-up transformer, and tested the associated potential transformers and ground fault detectors. Two days after the trip, the operators and electricians began to establish plant conditions to support high voltage testing of the main generator stator windings.

Four days after the trip, a quality control engineer discovered that a back-draft damper in the generator bus duct cooling system had failed. The back-draft damper was contained within the cooling air supply piping, downstream of the fan discharge. The damper prevented air flow from short circuiting through an idle fan. The plastic damper blade pivoting pins failed allowing four 71 cm [28 inch] by 10 cm [4 inch] aluminum damper blades to be carried up the air supply piping to the electrical bus bar. One damper blade shorted the bus bar to the bus duct causing the generator ground fault trip.

Technical support engineers developed minor modification 93-0504, "Iso-Phase Bus Duct Cooling Unit Dampers." The minor modification provided directions for replacing the

plastic pivot pins with steel pins, reinforcing the damper frame, relocating the damper blade linkage assembly, and installing a steel debris screen above the damper. Mechanics machined the new pivot pins, built the debris screen, and installed the redesigned damper.

The inspector reviewed the minor modification and held discussions with maintenance managers. The planners developed a methodical troubleshooting work flow schedule and coordinated activities between the maintenance, technical support, and quality assurance departments. The minor modification was through and extensive. The inspector concluded that the troubleshooting process was well managed and that the design changes to the iso-phase backdraft damper were extensive.

7.2 Safety-Related Lockout Relay

On January 4, 1993, a General Electric (GE) HEA lockout relay failed to trip during a routine maintenance test of a class 1E breaker. The inspector held discussions with technical support engineers and determined that the testing failure was the 15th failure of a GE HEA relay to trip at 70% rated voltage. The GE HEA relays perform electrical tripping functions when activated by protective devices on the switchgear. The relays are mounted on the rear side of the switchgear front with the reset handle located on the front of the switchgear. Because of the length of the contact portion, the contact portion is located in a vertical position and the reset handle is in a horizontal position. This arrangement requires the use of 90 degree gearing.

There are 38 class 1E HEA relays that the licensee tests, on a staggered three year period, using maintenance procedure LS0563.19, "G.E. Type HEA Lockout Relay Inspection, Testing, and PM." LS0563.19 requires the HEA relays to be tripped at 70% rated voltage (IEEE/ANSI Standard C37.90) and also to be functionally tripped by manual movement of the protective relay contact. In mid 1991, seven class 1E HEA relays installed in switchgear SWG-E5 failed testing as specified by procedure LS0563.19. An additional relay failed on March 2, 1992. Electricians conducted on-site bench testing from March 31, 1992, through April 23, 1992, to determine root cause of the failures. Technical support engineers contacted GE for technical assistance.

North Atlantic initiated station information report (SIR) 92-15 to determine reportability as required by 10 CFR Part 21. In the resulting engineering report, "GE HEA Relay Failures for 10 CFR Part 21. Reportability," issued on May 14, 1992, the licensee determined that the HEA relay test failures did not fall within the 10 CFR Part 21 reporting requirements. The report determined there was a low probability of an electrical fault, redundant equipment was available, and there was no apparent manufacturing defect. The inspector agreed that these test failures did not have to be reported in accordance with the requirements of 10 CFR Part 21.

On July 23, 1992, technical support engineers modified procedure LS0563.19 based on GE recommendations and on the electrician's on-site bench tests. The applied test voltage was

changed to 70% rated voltage from gradually increasing the applied voltage that caused increased coil temperature and resistance. As specified by the IEEE/ANSI standard C37.90, the supply voltage was required to be regulated so that ripple voltage did not exceed 5%. The engineers added a precaution from GE's instruction bulletin, GEH-2058D, to not rotate the relay reset handle against the latch, which could cause the relay to fail to trip. Since revising the testing procedure, seven additional HEA relays have failed during testing.

In September 1992, two failed HEA relays, one from the 'A' feedwater pump and one from the 'B' service water pump, were sent to an independent laboratory for evaluation of root causes of failure. The laboratory, NTS, conducted extensive root cause determination testing in accordance with the requirements of NTS/Northeast's Quality Manual to ensure program compliance to applicable provisions of 10 CFR Part 21, and Part 50, Appendix B. NTS report No. 60123-93N, dated October 8, 1992, concluded that friction associated with the latching rollers and bearing was the most probable cause of the test failures. The report noted that other factors contributing to the relay test failures were under torqued tie rods, dried grease lubricants in the right angle drive assemblies, and misaligned coil housings.

The 15 HEA relays that failed to trip 70% rated voltage during testing have been replaced from Unit 2 stock. Testing during the last two years included 32 relays of the 38 total relays. No relays have failed during actual demand situations or during 100% rated voltage testing. None of the relays replaced from Unit 2 stock have failed to trip when tested. The electricians continued to bench test relays to ascertain whether lubrication of the latching rollers and bearings would reduce friction and the number of testing failures. If a relay fails to trip with tripping voltage greater than 70%, the licensee proposed to add a 0.015 inch shim under the trip coil, to decrease the air gap between the trip coil pole face and the trip latch. Shimming the trip coil is in accordance with GE instructions.

The licensee purchased new HEA relays from GE and noted differences from the old relays. The latching roller diameter of the new relays was larger and the latch bar had an indent. GE informed the licensee that the noted changes were to improve manufacturing. The licensee believed the design modifications would improve relay performance.

The inspector reviewed the root cause of the HEA relay failures to trip during testing remained inconclusive; however, the inspector concluded that the licensee was making a good effort to determine the root cause of failure.

7.3 Equipment Environment Qualification

During a plant walkdown in the west steam and feedwater pipe chase, the inspector observed temporary air ducts directing air toward a component of the main steam (MS) and feedwater (FW) isolation valves. The inspector held discussions with operations and technical support personnel. Operations personnel did not know the function of these temporary air ducts; however, technical support personnel stated that the air ducts were installed to lower the temperature of the MS and FW isolation valves.

In July 1990, the licensee installed exhaust fans at the south end louver of the east and west MS and FW pipe chases to reduce the temperature within the pipe chases. Safety-related equipment has estimated qualified lifetimes based on equipment components being subjected to a maximum environmental temperature. Exposure to higher environmental temperatures reduces the expected lifetime of safety-related equipment. In July 1992, the licensee installed cooling coils at inlet fans using circulating water from a fire hose and a temporary pump to further reduce the inlet air temperature. In January 1993, the setpoint of the temperature control switch in the west chase was lowered from 90 to 70 degrees F to reduce room temperatures. The licensee added insulation to the MS and FW isolation valve bonnets to reduce the temperature of the limit switches and actuators. The licensee plans to conduct an infrared temperature survey to identify hot spots and insulation degradation. The licensee plans to balance the ventilation system to provide cooling to safety related components within the pipe chase. The temporary air ducts will remain for the present time.

The licensee developed a procedure EQ 2.4, "Ambient Temperature Verification," dated June 1, 1992, for monitoring and tracking component temperatures. Monitored temperatures would be used to determine the qualified life based upon a form of Arrenhius Equation detailed in Administrative Procedure EQ 2.2, "Qualified Life Extension Calculation," dated June 1, 1992.

Technical support engineers began recording temperatures of the MS and FW isolation valves on October 30, 1992, and plan to continue to record temperatures until the qualified life of the equipment is well established. Technical Support engineers made preliminary calculations of the qualified life of the MS isolation valve actuators and limit switches based upon exposure of one year at 160°F and the remainder of the life at 130°F. The estimated qualified life remaining from November 1, 1992, was 6.7 years for the actuators and 5 years for the limit switches.

The inspector concluded that the licensee has addressed the concerns identified in NRC Information Notice 89-30, "High Temperatures at Nuclear Power Plants," through procedures EQ 2.2 and EQ 2.4, ongoing temperature reduction effort, temperature monitoring, and qualified life calculations.

7.4 Motor Operated Valve Torque Switch Setting: Unresolved Item 91-81-01 (Closed)

During the NRC motor operated valve (MOV) team inspection, the team reviewed the licensee's calculation SBC-447, "Refueling Outage 1 MOV Min/Max Torques Switch Settings," and noted that valves SI-V77 and SI-V102 were determined to have inadequate actuator torque capability under degraded voltage conditions. Calculation SBC-447 referred to test results that had been conducted by Limitorque that indicated an adequate torque margin existed at 80% degraded voltage conditions. The NRC team reviewed Westinghouse letter, NAH-3219, dated February 19, 1987, and determined that there was no auditable documentation, on site, that specified the test method used or how actuator output capability was measured.

The test method used by Westinghouse to determine actuator output capability was transmitted to Seabrook in Westinghouse letter, NAH-92-3847, dated January 13, 1992. Westinghouse Specification 565682, Rev. H. specified the test procedure that Limitorque Corporation used.

Westinghouse reviewed the required operating loads for valves and the Limitorque test results for valve actuators. Westinghouse selected an actuator that was acceptable for the intended application of the valve. The actuator was installed on the valve and Westinghouse functionally tested the MOV prior to shipment. Westinghouse used Limitorque test data in conjunction with actual valve testing performed at 80% and 100% of nominal voltage to verify, within the constraints of the test facility, that the valve and actuator would function as required.

Westinghouse submitted the original test data for 14 of 50 Limitorque operators to Seabrook in their letter NAH-92-3903, dated April 28, 1992. In an internal engineering memorandum, "NRC MOV Inspection at Seabrook Westinghouse MOV Sizing Methodology," dated November 9, 1992, an engineer stated that "Seabrook plans to obtain and review Westinghouse test data for all Westinghouse motor-operated valves."

The inspector met with the engineering personnel responsible for the design-basis operability of safety related MOVs as required by Generic Letter (GL) 89-10 and Supplements. North Atlantic's program to address GL 89-10 recommendations is described in Station Procedure ES1850.000, "Motor-Operated Valve Performance Monitoring."

North Atlantic obtained MOV data from Westinghouse and Limitorque for the MOVs that were testing during the first two refueling outages. North Atlantic used the Westinghouse methodology to calculate MOV thrust/torque loads until half way through the first refueling outage. North Atlantic then began to use the more conservative Limitorque methodology. After the third refueling outage, North Atlantic planned to use the Limitorque methodology to retest the MOVs that were tested based upon the Westinghouse methodology calculations. The licensee stated that the MOVs tested using the Westinghouse methodology will function under the maximum design basis conditions.

The inspector determined that North Atlantic has an extensive and complete program to validate the safety-related design basis and diagnostic testing of MOVs. North Atlantic has obtained auditable documentation that specifies the test methods and techniques used to measure actuator output capability. This unresolved item regarding MOV torque margins at 80% degraded voltage condition and auditable documentation is closed.

7.5 Thermal Barrier Heat Exchanger: Unresolved Item 92-80-03 (Closed)

The NRC identified that the design specification for the tube side of the thermal barrier cooling water (TBCW) system heat exchanger used an environmental design temperature of 200°F. The TBCW system heat exchanger separates the component cooling water system

from the TBCW system which cools the thermal barriers of the reactor coolant pumps. The NRC questioned how the tube side of the heat exchanger could function as a closed system for containment isolation purposes since the containment environmental design temperature is 300°F. North Atlantic began evaluations to qualify the heat exchanger to the containment design temperature.

The engineering department completed document revision request (DRR) 92-134, "Thermal Barrier Heat Exchanger Qualification," which included a 10 CFR 50.59 evaluation and calculation C-S-1-45254. The inspector reviewed DRR-92-134. Calculation C-S-1-45254 demonstrated the structural integrity of the thermal barrier heat exchanger, and the piping associated with the heat exchanger nozzles at an environmental temperature of 300°F. The only calculations that did not assume a 300°F temperature for qualification of the heat exchanger and the associated piping to the heat exchanger nozzles were the seismic analysis and code calculation for the heat exchanger. Engineers marked up the original calculation using an assumed environmental design temperature of 300°F instead of 200°F. The stress on the nozzles, shells, and supporting material for the heat exchanger was recalculated and compared to the allowed stresses for faulted conditions. The component with the lowest design margin was the heat exchanger baseplate.

The engineering department reviewed closed systems designed to general design criteria (GDC) 57 to ensure components in the systems were qualified for containment design temperature. Other closed systems besides the component cooling water system have normal process temperatures exceeding the containment design temperature. The engineering department concluded that components in closed systems are qualified for containment isolation in accordance with GDC 57 criteria.

The inspector verified that the calculated stresses for the thermal barrier heat exchanger were within the allowable stresses and that the actual thickness of components were greater than the calculated thickness required for faulted conditions. The inspector concluded that calculation C-S-1-45254 qualified the thermal barrier heat exchanger for 300°F. This item is closed.

8.0 Safety Assessment/Quality Verification (71707, 92701)

8.1 Refueling Outage Assessment

The quality assurance group conducted an exit meeting on January 13 that concerned the audit findings made during the second refuel outage. The inspector reviewed the information package that was presented at the exit meeting. The audit package documented various trend analyses and specific audit findings.

The trend graphs compared the total number of the different types of audit findings made during the first and second refueling outages. The root cause distribution between equipment, personnel error, and tools was approximately the same. The total number of

audit findings was consistent with the first refueling outage, except that there were 56 operating information reports (OIRs) generated as compared to 20 OIRs generated during the first outage. The quality assurance group attributed the increase to a lower reporting threshold. The inspector considered the lower reporting threshold to be positive since it allows management to identify potentially adverse trends before they become a more significant problem.

In summary, the inspector assessed that North Atlantic has an established process in place that effectively identifies performance trends.

8.2 Reactor Trip Due to Low Steam Generator Water Level: LER 92-17 (Closed)

During a shutdown to commence the refuel outage on September 7, 1992, a low-low water level in steam generator 'C' initiated a reactor trip. The event was documented and assessed in NRC Inspection Report No. 50-443/92-15. The inspector reviewed the licensee event report, the station information report, the post trip review package, the root cause evaluation, and the human performance enhancement system evaluation. The inspector agreed with the North Atlantic root cause that operator error caused the reactor trip. Operators did not effectively coordinate actions between the primary and secondary plant operators in a manner to maintain stable steam generator water levels at low reactor power.

The inspector assessed that North Atlantic took adequate corrective actions to prevent recurrence of this event. Although the LER listed four other occurrences where high-high steam generator level resulted in a feedwater isolation, the LER did not develop the applicability or effectiveness of past corrective actions. The inspector considered this a weakness.

9.0 MEETINGS (30702)

The scope and findings of the inspection were discussed periodically throughout the inspection period. An oral summary of the inspection findings was provided to the station manager and his staff at the conclusion of the inspection period.

The resident inspector conducted the following exit meeting during this time period.

DATE	SUBJECT	REPORT NO.	INSPECTOR
Jan.20	Special Inspection	93-01	R. Laura N. Dudley F. Paulitz