U. S. NUCLEAR REGULATORY COMMISSION

REGION 1

050272-841014	050311-841004
050272-841019	050311-841213
050272-841020	
050272-841022	
050272-841106	
050272-841111	
050272-841118	

Report Nos. 50-272/84-42
50-311/84-42

Docket Nos. 50-272
50-311

License Nos. DPR-70
DPR-75

Licensee: Public Service Electric and Gas Company
80 Park Plaza
Newark, New Jersey 07101

Facility Name: Salem Nuclear Generating Station - Units 1 and 2

Inspection At: Hancocks Bridge, New Jersey

Inspection Conducted: October 17 - December 14, 1984

Inspectors: for J. C. Linville, Senior Resident Inspector — 1.8.85 date

for R. J. Summers, Resident Reactor Inspector — 1.8.85 date

Approved By: L. J. Norrholm, Chief, Reactor Projects Section No. 2B, Projects Branch No. 2, DPRP — 1/9/85 date

Inspection Summary:
Inspections on October 27 - December 14, 1984 (Combined Report Numbers 50-272/84-42 and 50-311/84-42)

Areas Inspected: Routine inspections of plant operations including: status of previous inspection items, review of periodic and special reports, licensee event report review, operational safety verification, surveillance observations, maintenance observations, ESF system walkdown, operating events and IE Bulletin followup. The inspection involved 264 inspector hours by the resident NRC inspectors.

Results: Two violations were identified: one involving failure to comply with 10 CFR 50.59 requirements for not having a written safety evaluation for changes to the facility involving scaffolding (paragraph 5c); the other involving failure to comply with 10 CFR 50 Appendix B criterion V for not providing adequate procedures to control a safety related maintenance activity (paragraph 7). Other concerns discussed requiring licensee action include: additional response to NRC concerns about issues surrounding the operability of valve 1CV69 (paragraph 2); updating the corrective action for Unit 1 LER 84-21 to include Limitorque maintenance procedure changes to prevent recurrence (paragraph 4); resolving reactor coolant system unidentified leakage determination (paragraph 5b); continuing licensee efforts to identify the cause of the apparent EHC problems (paragraph 10a); and completing actions per the licensee's revised response to IE Bulletin 84-03 regarding refueling cavity seal integrity.

DETAILS

1. Persons Contacted

Within this report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activity.

2. Status of Previous Inspection Items

(Closed) Inspector Followup Item (311/84-08-04) This item involved a modification to bus bar bracing in GE 4160 volt metal-clad switchgear to assure adequate support under design short circuit conditions based on a deficiency identified at the Shoreham facility. The inspector verified that the bracing modification was installed in accordance with the General Electric final report dated October 12, 1983 on selected cubicles in the 2C vital bus during the bus outage.

(Closed) Violation (50-272/84-36-01) This item was described in NRC Inspection Report 50-272/84-36; however, a Notice of Violation was not issued at that time. Subsequent to the issuance of the referenced report and the licensee's Unit 1 LER 84-22, which detailed the same event, additional information became available which has resulted in withdrawal of the violation. It was determined that valve 1CV69 had not failed a leak rate test as previously stated and therefore was operable when the operators used it on October 18, 1984 as the containment isolation valve. This item is considered closed for administrative purposes. However, related issues as discussed in our letter dated December 6, 1984 are still outstanding. First, the failure of the licensee's program to identify status of this equipment to the operators. On October 19, 1984, the operators did not know whether 1CV69 had successfully passed a leak rate test and again, on November 27, 1984, the operators were still unsure of the status. No guidance had yet been provided to preclude inadvertent use of 1CV69 as an isolation valve after December 10, 1984, when the current leak test surveillance interval expires. Second, although the Technical Specifications permit testing of either CV68 or CV69, the decision not to test CV69 following an inconclusive test on April 9, 1984 was questionable. Even though a problem was subsequently identified with the test boundary valves, a prudent course of action for resolution of a questionable unsatisfactory test for a safety-related component would have included a subsequent retest of that component to determine its acceptability. Third, the length of time it took for the licensee to establish the facts surrounding this event was a concern. The acceptability of CV69 as an operable isolation valve was not determined until after it had been erroneously documented, in Unit 1 LER 84-022, that it had failed a leak rate test. The need for better documentation is evident in this case. In addition, Unit 1 LER 84-22 is no longer valid. The licensee response to these issues will be reviewed during a future inspection (272/84-42-01).

(Open) Unresolved Item (50-311/84-35-01) This item involved the apparent failure to conduct special steam generator tube inspections in accordance with Technical Specification surveillance requirement 4.4.6.3c following a reactor coolant system (RCS) depressurization event on July 25, 1984. The bases for the surveillance requirement did not specify the size of the LOCA that would require the special inspections. The licensee has conducted eddy current examinations during the current refueling outage to satisfy the surveillance requirement. Although a total of 6 defective tubes were identified, these were a result of additional focused examinations of peripheral and first row tubes due to problems with vibrating tube lane blocking devices and loose parts that were found by visual examination. These defective tubes were apparently not a result of the July 25th event. The required examination, which has been conducted, showed that no apparent RCS pressure boundary degradation has occurred. However, the item is still unresolved pending determination whether the July 25th event was one that required the special examinations.

3. Review of Periodic and Special Reports

Upon receipt, the inspectors reviewed periodic and special reports. The review included the following: inclusion of information required by the NRC; test results and/or supporting information consistent with design predictions and performance specifications; planned corrective action for resolution of problems, and reportability and validity of report information. The following periodic reports were reviewed.

-- Unit 1: Monthly Operating Report - October 1984
   Monthly Operating Report - November 1984

-- Unit 2: Monthly Operating Report - October 1984
   Monthly Operating Report - November 1984

No violations were observed.

4. Licensee Event Report (LER) Review

The inspectors reviewed LER's to verify that the details of the events were clearly reported. The inspectors determined that reporting requirements had been met, the report was adequate to assess the event, the cause appeared accurate and was supported by details, corrective actions appeared appropriate to correct the cause, the form was complete and generic applicability to other plants was not in question. Details of onsite followup are included, if applicable.

Unit 1

84-21 Containment Isolation Valve 1CC131 Inoperable

This report details an event which caused an inadvertent automatic closure of valve 1CC131. Subsequently, while returning the valve to its normal, open position, the Limitorque operator failed. This made the valve inoperable and required the shutdown of the reactor from Mode 2 (Startup) in accordance with the Technical Specifications. Corrective actions did not include steps to be taken by maintenance personnel to prevent future similar Limitorque failures. However, based on discussions with Maintenance Department management, additional corrective measures are being developed. When these are completed, a revised LER will be issued to better detail the cause of the limitorque failure and the additional corrective actions. In addition, a supplemental report will be issued following an engineering review of the plate type component cooling heat exchanger "flexing phenomena" which initiated the event. The inspector will review the revised LER when issued (272/84-42-02).

84-22 Containment Isolation Valves 1CV68 and 1CV69 Inoperable

Followup of this event is documented in paragraph 2 of this report.

84-23 Reactor Trip From 8% Power During Testing

This report detailed a reactor trip from 8% power during overspeed turbine testing. Initial followup of this event is documented in NRC Inspection Report 50-272/84-36; 50-311/84-35. The reactor trip occurred due to a failed turbine impulse pressure transmitter, in coincidence with the turbine trip, as expected during the test. The failed transmitter was replaced with that of a different design to prevent future similar failures. In addition, the test procedure was revised to verify that the required permissives were made up prior to initiating the turbine trip to avoid future unnecessary challenges of the Reactor Protection System.

84-24 Engineered Safety Feature Actuation System - Feedwater Isolation Malfunction

This report detailed a partial Feedwater Isolation that apparently resulted from an ESFAS malfunction. The unit was subsequently shutdown from 5% power in accordance with the Technical Specifications when initial testing could not determine the cause. Following additional testing, no cause was identified and the event could not be reproduced. Since no prior similar malfunctions have occurred and the event could not be reproduced during testing, appropriate corrective actions to prevent future events could not be determined. Although failure to identify the cause of the event is a concern, the inspector had no additional questions at this time based on information available.

84-25 Reactor Trips from 91% and 93% Power

This report detailed reactor trips that occurred November 6 and 11, 1984 as a result of apparent malfunctions of the Electro-Hydraulic Control (EHC) System. On both occassions unexplained rapid load rejections caused a "shrink" in steam generator levels resulting in reactor trips due to low-low level in No. 13 Steam Generator. Additional details of these events are discussed in paragraph 10A of this report.

84-27 Service Water Leaks Inside Containment

This report detailed two separate service water system leaks into containment on November 18, 1984, which were reportable in accordance with IE Bulletin 80-24. The apparent cause of the leaks was due to failures in carbon steel, cement lined vent lines as a result of external surface corrosion due to condensation and some galvanic effects at the valve flange mating areas resulting from dissimilar metals. Temporary repairs were made, replacing the carbon steel pipe with 316 stainless steel pipe. Upon receipt of materials (carbon steel pipe) and an outage of sufficient duration, a permanent repair will be made. In addition, a test procedure is being developed for the service water piping in containment to aid in early detection of the degraded pipe. The inspector will follow the licensee's actions to make the permanent repairs (272/84-42-03).

5. Operational Safety Verification

a. Control Room Observations

Daily, the inspectors verified selected plant parameters and equipment availability to ensure compliance with limiting conditions for operation of the plant Technical Specifications. Selected lit annunciators were discussed with control room operators to verify that the reasons for them were understood and corrective action, if required, was being taken. The inspectors observed shift turnovers biweekly to ensure proper control room and shift manning. The inspectors directly observed operations to ensure adherence to approved procedures.

b. Shift Logs and Operating Records

Selected shift logs and operating records were reviewed to obtain information on plant problems and operations, detect changes and trends in performance, detect possible conflicts with Technical Specifications or regulatory requirements, determine that records are being maintained and reviewed as required, and assess the effectiveness of the communications provided by the logs.

During a review of the results of the SP(O)4.4.6.2d Reactor Coolant

System (RCS) Water Inventory Balance data for November 28-30, 1984 the inspector noted some inconsistencies. The purpose of the RCS Inventory Balance is to determine the total reactor coolant system leakage. From the RCS Inventory Balance identified leakage to the pressurizer relief tank (PRT), the reactor coolant drain tank (RCDT) and other measured RCS leaks are subtracted leaving a remainder which the licensee calls Unclassified Intersystem Leakage. While Intersystem Leakage is a term described in Regulatory Guide 1.45, Reactor Coolant Pressure Boundary (RCPB) Leakage Detection Systems, it is not defined in the facility Technical Specifications.

On November 28, 1984 the unclassified intersystem leakage was 0.354 gpm excluding 0.12 gpm measured leakage from the PRT. On November 29 and 30, 1984 the unclassified intersystem leakages were 0.903 and 0.88 gpm respectively again excluding 0.12 gpm leakage from the PRT but based on no observed level change in the PRT during the test. It appeared that the PRT leakage from November 28 had been carried over to November 29 and 30. In discussing this possibility with one licensed reactor operator, the inspector found that different operators may use different PRT level indicators to perform the test. The computer point provides indication to the nearest one tenth of one percent while the panel bezel indicator is divided into 2 percent increments. The procedure did not specify which indicator to use. Discussion with another licensed reactor operator who performed one of the tests in which an error in PRT leakage was made revealed that he considered it acceptable to use PRT level data from an earlier test. While the procedure does not specify that PRT data from the same time period during which the RCS inventory balance is being conducted be used to calculate PRT leakage, it implies it by requiring that the PRT data be recorded.

On December 1, 1984, the licensee made repairs to 1CV8 in an effort to reduce unclassified intersystem leakage, but it remained close to 1 gpm until the licensee identified and quantified 1.25 gpm leakage by drain valve 1CV346 to the RHR sump on December 10, 1984.

The NRC Region I position is that the difference between the RCS inventory balance and identified leakage, as defined in the Technical Specifications, is unidentified leakage. Identified leakage is defined as:

a. Leakage (except controlled leakage) into closed systems such as pump seal or valve packing leaks that are captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary leakage, or

c. Reactor Coolant systems leakage through a steam generator to the secondary system.

Controlled leakage is that seal water flow from the reactor coolant pump seals. Unidentified leakage is all leakage which is not identified leakage or controlled leakage.

Technical Specification 3.4.6.2 limits unidentified leakage to 1 gpm, identified leakage to 10 gpm and controlled leakage to 40 gpm in modes one through four. Action statement b. requires that with leakage greater than any of those limits, that the leakage be reduced to limits within 4 hours, or be in at least hot standby within the next 6 hours and in cold shutdown within the following 30 hours. The Technical Specification 4.4.6.2 Surveillance Requirements are that RCS leakage be demonstrated within these limits by:

a. monitoring the containment atmosphere particulate radioactivity monitor at least once per 12 hours,

b. monitoring containment sump inventory at least once per 12 hours,

c. measurement of controlled leakage from reactor coolant pump seals once per 31 days,

d. performance of RCS water inventory balance at least once per 72 hours with the plant at steady state conditions, and

e. monitoring reactor head flange leakoff system at least once per 24 hours.

The licensee's position is that intersystem leakage is not unidentified leakage since it is not RCS leakage into the containment and it does not interfere with the operation of leakage detection systems such as the sump pumps or containment particulate radioactivity monitors. In addition, since Technical Specification 3.4.6.3 permits as much as 5 gpm leakage from each of 25 check valves connected to the RCS, the licensee maintains that it is unreasonable to limit total leakage through these paths to 1 gpm unidentified leakage. This item is unresolved pending further NRC review (272/84-42-04).

c. Plant Tours

During the inspection period, the inspectors made observations and conducted tours of the plant. During the plant tours, the inspectors conducted a visual inspection of selected piping between containment and the isolation valves for leakage or leakage paths. This included verification that manual valves were shut, capped and locked when required and that motor operated valves were not mechanically blocked.

The inspectors also checked fire protection, housekeeping/cleanliness, radiation protection, and physical security conditions to ensure compliance with plant procedures and regulatory requirements.

--At about 9:20 a.m. on November 5, 1984, the licensee identified a leak of contaminated liquid from an overhead vent duct on the 100' elevation of the Unit 2 auxiliary building near the auxiliary feedwater pumps. This event was documented in LRC 84-243. Subsequent licensee investigation showed that this was reactor coolant which had backed up from a letdown line drain valve, 2CV12, while draining to lower reactor vessel level while in Mode 5. It appears that 2CV12 was opened to drain the letdown line penetration for Local Leak Rate Testing of valves 2CV3, 4, 5, and 7. After the penetration was drained 2CV12 was inadvertently left open. Prior to performance of the test, Tagout No. 027126 for the test which had been completed on November 4, 1984 was temporarily released to permit draining of the reactor vessel. Since 2CV12 had not been tagged, it remained open causing the spill.

The licensee personnel who identified the spill immediately isolated the area and stopped the spill by closing the drain valve. As a result of Operations Department review of the event a memo was drafted to all Operations Department personnel reminding them of their responsibilities to tag vent and drain valves repositioned for draining operations. This is a licensee identified violation of Administrative Procedure 15, the Safety Tagging Procedure, which requires that vent and drain valves which could result in an energy release be tagged.

--During a tour of the Service Water Intake Structure on December 14, 1984, the inspector observed that scaffolding had been erected in the Unit 1 Service Water pump bays, directly above all six pump strainers. The scaffolding was erected to support implementation of Design Change Package (DCP) 1EC-1475; this design change involves painting and identifying all overhead cranes. The scaffolding was erected over safety related equipment required to be operable. No written safety evaluation was developed to justify erecting the scaffolding which is a temporary modification to the structure as defined in the FSAR.

On November 7, 1984, the inspector observed that scaffolding had been erected in the Unit 1 4KV vital switchgear room. This scaffolding was erected in support of implementing DCP 1EC-1678. As with the case detailed above, this scaffolding also potentially affected safety related equipment required to be operable and no written safety evaluation was developed. Failure to provide written safety evaluations stating the basis for determining that erection of scaffolding near safety related structures, systems and components required to be operable **does not** constitute an unreviewed safety question is a violation of 10 CFR 50.59 (272/84-42-05).

In addition, this problem had been previously identified in NRC Inspection Report 50-272/84-32; 50-311/84-32. At that time, the licensee stated that all scaffolding would be removed by September 14, 1984, or justified by a safety evaluation. The licensee removed the scaffolding in the electrical penetration area that was in question prior to returning the unit to service from a refueling outage. However, no apparent steps have been taken to control use of scaffolding in the operating unit's safety related areas as indicated by the two examples above.

d. Tagout Verification

The inspectors verified that selected safety-related tagging requests were proper by observing the positions of breakers, switches and/or valves.

6. Surveillance Observations

The inspectors observed portions of the surveillance procedures listed below to verify that the test instrumentation was properly calibrated, approved procedures were used, the work was performed by qualified personnel, limiting conditions for operation were met, and the system was correctly restored following the testing:

-- 1PD 2.6.020 Channel Functional Test 1LT-459 Pressurizer Level Protection - Channel I

-- 1PD 16.2.011 Channel Functional Test - Nuclear Instrumentation - Source Range Channel 1N31

-- 1PD 16.2.007 Channel Functional Test - Nuclear Instrumentation - Power Range Channel 1N41

-- 1IC 16.4.047 Nuclear Instrumentation - Miscellaneous Procedure, Bypass Channel 1N44

-- M16E, Local Leak Rate Test Program - testing containment electrical penetrations

7. Maintenance Observations

a. The inspectors observed portions of various safety-related maintenance activities to determine that redundant components were operable, these activities did not violate the limiting conditions for operation, required administrative approvals and tagouts were obtained prior to initiating the work, approved procedures were used or the activity was within the "skills of the trade," appropriate radiological controls were properly implemented, ignition/fire prevention controls were properly implemented, and equipment was

properly tested prior to returning it to service.

b. During this inspection period, the following activities were observed:

-- Troubleshooting EHC per Work Order 009901437-8

-- Replacing No. 12 Charging/Safety Injection pump speed increaser per Work Order 009912559-5

-- Repairing No. 13 Service Water Pump - packing leak per Work Order 84-11-23-066-0

-- Replacing No. 11 Service Water Pump Expansion Joint per Work Order 84-11-26-012-7

With respect to maintenance on the service water (SW) expansion joint a number of issues were discussed with the licensee. First, the work observed was conducted using the general troubleshooting and repair procedure M11E. This procedure is not adequate, due to omission of detailed installation tolerances recommended by the manufacturer of the component which include axial compression and extension, and lateral deflection. However, since the supervisor in charge of the job was knowledgeable of the axial compression and extension requirements, the replacement was done without exceeding them by installing a spacer.

Documentation of recent expansion joint replacements for Unit 1 and work in progress for Unit 2 was reviewed to see if the installations were adequate. Catalytic personnel replaced a number of the 24 and 30 inch SW expansion joints and although installation within the manufacturer's tolerances could not be independently verified, the procedure required a signoff step stating that axial compression and extension were not exceeded. Specific guidance on the installation including axial and lateral tolerances and precautions to prevent overstressing the components through improper support were not addressed in the procedures.

In addition, for a number of the spare joints used, the recommended shelf life time had expired. The licensee justified use of these materials by conducting the same hydrostatic test used by the vendor per Word Order MD 947253-2401. Following this test the licensee did not specify a new expected service life for the joints beyond the vendor recommendation based on newly manufactured expansion joints. The installed joints that were stored in excess of the vendor recommended shelf life, were therefore not evaluated to determine the proper replacement time.

The licensee identified the need for adherence to the manufacturers installation tolerances as a result of a failure of a joint on November 19, 1984, which had just been installed on about October 29, 1984.

Prompt, effective corrective actions were not taken to ensure that subsequent work was acceptable. Failure to provide adequate procedures, for maintaining and installing Service Water expansion joints, which include quantitative acceptance criteria, such as service life criteria and installation tolerances, is a violation of 10 CFR 50 Appendix B Criterion V and Section 17.2.5 of the Salem Generating Station UFSAR. These acceptance criteria are necessary to determine that important activities affecting quality, such as replacing the expansion joints, have been satisfactorily accomplished (272/84-42-06; 311-84-42-01).

8. Engineered Safety Feature (ESF) System Walkdown

The inspector verified the operability of the selected ESF system by performing a walkdown of accessible portions of the system to confirm that system lineup procedures match plant drawings and the as-built configuration, to identify equipment conditions that might degrade performance, to determine that instrumentation is calibrated and functioning, and to verify that valves are properly positioned and locked as appropriate. The Unit 1 Control Room Ventilation System was inspected. No adverse conditions were identified; however, direct access to the ventilation system from the control room is not available which is not consistent with the description of the system layout provided in the FSAR. A change to the FSAR is necessary to better describe the current configuration.

9. Refueling Preparations

The inspector reviewed the procedures for receipt, inspection and storage of new fuel. No deficiencies were noted during observation of receipt inspection and storage of two new fuel assemblies in the new fuel storage vault.

10. Operating Events

A. Unit 1

At 6:46 a.m. on November 6, 1984, the unit tripped from 91 percent power due to low low level in No. 13 Steam Generator. All safety systems responded normally. After the trip, the control room operator inadvertently tripped all operating condensate pumps causing a water hammer in the condensate system piping which broke a pipe hanger, damaged piping insulation, and broke a condensate bypass valve positioner. The licensee inspected the system, radiographed the feedwater flow nozzles and repaired the damage prior to restart except the insulation which was repaired during operation. The unit was returned to service on November 9, 1984. At 1:09 a.m. on November 11, 1984, the unit tripped from 93 percent power due to low-low level in No. 13 Steam Generator. Preliminary licensee investigation indicated

that the cause was an EHC system malfunction involving closure of the governor valves similar to that which caused the November 6 trip.

Investigations of the EHC following both events did not identify the root cause of the failure. Suspect circuit cards in the EHC were replaced; however, conclusive evidence of failure could not be determined. Additional steps such as monitoring EHC outputs have been implemented to identify the failure. The unit is currently being operated with the EHC system in turbine manual with the Overspeed Protection Circuit (OPC) in the "overspeed test" position to prevent future inadvertent reactor trips until the root cause can be identified and corrected. A safety evaluation was conducted for operations in this manner, which concluded that there were no safety concerns provided that certain conditions were met such as testing of the mechanical overspeed trip device and implementing the turbine valve test requirements that are required for Unit 2. The inspector will continue to follow the licensee's actions to identify the root cause of the EHC problem and eventual return to normal mode of turbine control (272/84-42-07).

Following a 10 day outage to investigate problems associated with the EHC system and to make repairs for reactor coolant and service water leaks in the containment, the reactor was taken critical at 7:40 p.m. on November 20, 1984. Following repairs to the No. 12 Charging/Safety Injection pump speed increaser, the licensee synchronized the unit to the grid and began power escalation at 11:48 a.m. on November 22, 1984.

B. Unit 2

The licensee has decided to replace the Westinghouse Generator, which tripped on October 4, 1984 due to a failed coil header cap, with the General Electric generator originally intended for the cancelled Hope Creek Unit 2. The unit was in Cold Shutdown at the end of the report period with preparations for refueling in progress.

At 12:00 p.m. on December 13, 1984, 253 contractor personnel (Pipe-fitters) working at Salem NGS during the Unit 2 refueling outage, walked off the job due to a dispute over work assignments to Millwrights. The dispute involved contractor support only and no participation by the IBEW, which represents the station employees. All personnel returned to the job site on December 14, 1984 and negotiations resolved the issues. Normal plant operations were not affected.

11. Licensee Action on IE Bulletins

The inspectors reviewed the licensee's submittal, dated November 21, 1984 for IE Bulletin 84-03, Refueling Water Cavity Seals. The initial

submittal did not adequately assess or justify the continued use of the Salem cavity seals. The response included a safety evaluation which attempted to justify use of the present seal configuration through a qualitative assessment which concluded that seal failure was unlikely. The inspectors raised a concern during a meeting with the Engineering Department on December 7, 1984, about the lack of supporting data or analyses, such as actual seal test data in the response. In addition, other NRC concerns were identified in correspondence from R. Starostecki to R. Uderitz dated December 12, 1984. The licensee responded to these concerns by conducting quantitative tests on a sample of seal material which showed that sufficient safety margin existed, and revising the safety evaluation to address other concerns such as the consequences of dropping a heavy load like a fuel cell on the seal and the application of defense-in-depth philosophy to the seal configuration. At the end of the inspection period, only a draft copy of this safety evaluation was available for review. The inspector will continue to follow the licensee's actions in response to this Bulletin, including review of the final revised response and of procedures to provide a response for a cavity seal failure event (272/84-42-08; 311/84-42-02).

12. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. The unresolved item identified during this inspection is discussed in paragraph 5b.

13. Exit Interview

At periodic intervals during the course of this inspection, meetings were held with senior facility management to discuss inspection scope and findings. On December 14, 1984, the inspectors met with licensee representatives and summarized the scope and findings of the inspection as they are described in this report.