U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-440/90020(DRP)

Docket No. 50-440 License No. NPF-58

Licensee: Cleveland Electric Illuminating Company
Post Office Box 5000
Cleveland, OH 44101

Facility Name: Perry Nuclear Power Plant

Inspection At: Perry Site, Perry, Ohio

Inspection Conducted: September 20 through November 16, 1990

Inspectors: P. Hiland
G. O'Dwyer
A. Hsia
P. Pelke
D. Schrumm
R. Musser
F. Maura

Approved By: R. D. Lanksbury, Chief
Reactor Projects Section 3B

12/12/90
Date

Inspection Summary

Inspection on September 20 through November 16, 1990 (Report No. 50-440/90020(DRP))

Areas Inspected: Routine unannounced safety inspection by resident and regional inspectors of licensee event report followup; monthly surveillance observations; monthly maintenance observations; operational safety verification; engineered safety feature walkdown; onsite followup of events; and plant status meeting.

Results: Of the seven areas inspected, one violation was identified. The violation involved inadequate corrective actions (paragraph 2.a) and concerned the licensee's failure to prevent recurring, and worsening, leakage of the main steam lines. The licensee has continued to have problems with the as-found leakage rate of the four main steam lines, the main contributors being the main steam isolation valves. The licensee has not demonstrated an aggressive engineering, surveillance, and maintenance program to identify the root cause and correct the problem. This violation was receiving appropriate licensee attention at the close of the report period.

9012280064 901214
PDR ADOCK 05000440
Q PDR

For this report period, the area of plant operations was considered adequate based on the inspectors observations of plant evolutions and response to events. The area of maintenance and surveillance was considered a weakness due to failures of main steam lines and other containment penetrations to pass their local leak rate test surveillances. Of particular note was the detailed investigation into a rod scram time failure that occurred early in the report period.

In general, the inspectors found the areas of security and emergency preparedness to be a strength based on routine observations. The area of radiological controls was considered adequate; however, continued licensee management attention appears warranted to improve housekeeping in general and improve radiological practices at entries to contaminated areas. The inspectors noted that senior licensee management personnel were addressing the concerns in this area.

DETAILS

1. Persons Contacted

   a. Cleveland Electric Illuminating Company (CEI)

      +R. Miller, Chairman, Centerior Energy Corporation
      +R. Farling, President, Centerior Energy Corporation
      +M. Edelman, Executive Vice President, Centerior Energy Corporation
      #+M. Lyster, Vice President, Nuclear-Perry
      #+R. Stratman, General Manager, Perry Nuclear Power Plant (PNPP)
      * +M. Gmyreck, Operations Manager (PNPP)
      #+M. Cohen, Manager Maintenance Department (PNPP)
      #+V. Higaki, Manager, Outage Planning Section (PNPP)
      # D. Cobb, Operations Superintendent (PNPP)
      #+S. Kensicki, Director, Perry Nuclear Engineering Department (PNED)
      # V. Concel, Manager, Technical Section, (PNED)
      *#+F. Stead, Director, Perry Nuclear Support Department (PNSD)
      # H. Hegrat, Compliance Engineer (PNSD)
      *#+R. Newkirk, Manager, Licensing and Compliance Section (PNSD)
      *#+E. Riley, Director, Perry Nuclear Assurance Department (PNAD)
      * +W. Coleman, Manager, Perry Nuclear Assurance Department (PNAD)
      S. Cashell, Compliance, PNSD
      S. Seman, MSIV Activity Coordinator
      R. Boyles, Diesel System Engineer
      R. Wolf, Radiation Protection
      J. Krylow, Radiation Protection

   b. U. S. Nuclear Regulatory Commission

      +C. Paperiello, Deputy Regional Administrator, RIII
      +H. Miller, Director, Division of Reactor Projects, RIII
      +R. Lanksbury, Section Chief, RIII
      +J. Hannon, Director, Project Directorate III-3, NRR
      +R. Hall, Project Manager, NRR
      +P. Hiland, Senior Resident Inspector, RIII
      *#+G. O'Dwyer, Resident Inspector, RIII
      * R. Musser, Acting Senior Resident Inspector, RIII
      +P. Pelke, Project Engineer, RIII

   * Denotes those attending the exit meeting held on November 16, 1990.

   # Denotes those attending the Plant Status meeting on October 17, 1990.

   + Denotes those attending the public SALP exit meeting on October 30, 1990.

2. In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities (90712)

a. (CLOSED) Licensee Event Report No. 90-025 (440/90025-LL): All four main steam line (MSL) penetrations failed their local leak rate tests (LLRTs). On October 16, 1990, the licensee reported that all four MSLs had exceeded their allowable Technical Specification limit of 25 standard cubic feet per hour (SCFH). Table 1 shows the history of MSL reported leakage rates. The Main Steam Isolation Valves (MSIVs) at Perry are 26 inch Y-pattern stop valves manufactured by Atwood and Morrill.

Table 1 - History on MSL As-Found Leakage Rate

Leakage rate, in SCFH

	MSL A	MSL B	MSL C	MSL D
July 1987	>42.4	>42.4	32	>42.5
Sept. 1987	Not tested	610	Not tested	Not tested
Feb.-Mar. 1989	261	64	265	45
Sept. 1990	Indeterminate	4360	14,453	73
	>10,600*	>13,300*	1851*	95*

*After valve cycling

Additional testing showed that the main contributors to the MSL leakage were the "A" and "D" inboard and outboard MSIVs, the "B" and "C" outboard MSIVs, the leakage control system isolation valves in MSL "B" and "D", and the "A" outboard MSIV drain valve.

Table 1 shows that this is the third consecutive time the MSLs have exceeded their allowable leakage rate, and that the leakage rates are getting larger. During the 1989 refueling outage the inspectors reviewed the MSIV's maintenance records (Inspection Report No. 50-440/89012(DRS)) and noted that repairs consisted mostly of machining or lapping the valve seats, replacing two valve stems, and the repair of guide ribs on two valves. Valve measurements such as radial clearances between the valve bore and the disc/piston assembly were not taken. This lack of valve data, on parameters which may have an effect on proper valve operation and leak tightness, makes it more difficult to determine the root cause of the repeated failures.

Repairs this outage have been similar in nature to those performed previously. No major design changes have been incorporated. The licensee stated that valve internal measurements were taken this outage.

The licensee has been unable to implement a successful corrective action program which would result in MSLs as-found leakage rates being within the Technical Specification acceptance criteria. Further, it was noted that the licensee apparently has not pursued adjustments to the surveillance testing program, or the preventive maintenance program, to ensure that MSIVs will perform their safety function throughout an entire fuel cycle. This failure to demonstrate adequate corrective actions is a violation of 10 CFR 50, Appendix B, Criterion XVI (440/90020-01(DRS)).

No deviations were identified; however, one violation was identified.

3. Licensee Event Report Followup (92700)

Through direct observations, discussions with licensee personnel, and review of records, the following licensee event reports (LERs) were reviewed to determine that reportability requirements were fulfilled, that immediate corrective action was accomplished and that corrective action to prevent recurrence was accomplished in accordance with Technical Specifications. The LERs listed below are considered closed.

a. (Closed) LER 89-001-00/89-001-01: Oxidation of Division 2 Fuel Oil Resulted In Division 2 Diesel Generator Being Inoperable When Division 1 Diesel Generator Was Out For Planned Maintenance.

On January 5, 1989, a truckload of fuel oil was added to the Division 2 fuel storage tank. The fuel had passed the required tests prior to being discharged to the tank. However, the tank sample, drawn for the seven and fourteen day analyses, failed due to a high concentration of insolubles. On January 11, 1989, the Division 2 diesel generator was declared inoperable due to the condition of the fuel. During this time, the Division 1 diesel generator was out of service for planned maintenance. The Division 3 diesel generator was also placed in an inoperable state for 15 minutes for prestart checks.

Licensee's Evaluation of Cause and Corrective Actions

Root Cause

The licensee determined that the fuel oil problem was caused by normal fuel aging. Most of the fuel in the tank was four years old when the normal shelf-life was one year for number two fuel oil.

Also, a programmatic weakness existed in that licensee had not established any controls to prevent removing the other diesels from service for maintenance, etc., while waiting for the diesel fuel tests for the seven/fourteen day test samples.

Corrective Actions

- A dispersant agent was added to the Division 2 fuel storage tank to help break up the insolubles in the fuel oil. The dispersant agent was also added to the Division 1 tank. Division 1 and 3 fuel were tested as satisfactory.

- Division 1 diesel generator maintenance was completed and the diesel put back in service.

- Fuel oil samples were sent off-site for additional analysis.

- All three diesel fuel tanks were pumped down and refilled during the on-going refueling outage.

- An instruction was written to add a biocide, dispersant, and stabilizer to extend the shelf-life of the new fuel.

- A Technical Specification (TS) change was pursued to go to a higher grade diesel fuel oil with a longer shelf-life. The TS change was required due to a lower energy per unit volume and the additional fuel storage requirement and to change the American Petroleum Institute (API) gravity requirement.

- The diesel maintenance schedules were revised to ensure that they are not performed during outstanding surveillances.

- The System Operating Instruction (SOI) was revised to prevent prestart check requirements from being implemented if both the Division 1 and 2 diesel generators are inoperable.

Inspector's Review

By interview and review of records it was determined that the licensee has a well-structured inspection, sampling, and test program for the diesel fuel. Samples were being taken according to plant procedures and TS requirements. The test results were being tracked on data sheets which also indicated the trend of degradation of fuel over time.

The indicated licensee corrective actions had been performed to mitigate future problems with fuel aging. The licensee obtained the TS change to upgrade to the premium #2 fuel oil and during the 1990 refuel outage washed out the three diesel fuel tanks and day tanks, and refilled the tanks with premium #2 fuel oil.

The plant had two procedures, SOI-R45 and SOI-45/E22B, that required operations to ensure that the chemistry group had added biocide to the diesel fuel prior to the addition of new diesel fuel to the diesel generator storage tanks. Chemistry procedure OM12C.CHI-26 directed the chemistry technician to add one gallon of Betz GCP-983 biocide for every 1000 gallons of new fuel oil to be added to the storage tank. See LER 90-005-00/90-005-01 of this report for changes being made due to a biocide problem.

By review of system drawings, the inspector verified that system strainers exist between the fuel oil storage tank and the diesels to mitigate the effects of degraded oil. These strainers are cleaned on a repetitive basis via two procedures, SVI-R43-TS197 and SVI-E22-TS212. Differential pressure gauges/alarms existed for these strainers to alert operators that the strainers are plugging up and to switch to a parallel strainer. A work order would then be issued to clean the clogged strainer.

Based on the corrective actions taken as stated above and the additional corrective actions taken for LER 90-005-01, this item is considered closed.

b. (Closed) LER 90-005-00/90-005-01: Fuel Oil Degradation Causes Inoperability of High Pressure Core Spray System

On April 5, 1990, the High Pressure Core Spray system was declared inoperable due to the Division III diesel generator fuel oil being out of specification for sediment greater than 72 hours.

Licensee's Evaluation of Cause and Corrective Action

Root Cause

The fuel oil degradation was caused by a calcium contaminant found in the biocide additive. The calcium in the biocide reacted with the phosphate in the stabilizer in the fuel oil tank to form an insoluble calcium phosphate precipitate. Contributing to the problem was dissolved lead from the protective internal coat of paint of the fuel oil storage tank. The lead in the fuel oil helped to catalyze fuel oil degradation.

Corrective Actions

- During the 1990 outage (currently in progress), the three fuel tanks were pumped out and the fuel replaced with a premium #2 fuel oil.
- The contaminated biocide additive was removed from the site and future alternative fuel oil additives are being evaluated.
- The lead in the new fuel oil will be monitored to determine if the tank lining will be replaced during a future outage.
- The licensee was investigating the option of on-site filtering of fuel oil and other methods of improving the fuel storage.

Inspectors Review

Based on the comprehensive actions taken as stated for LER 89-001-00/89-001-01 of this report and the licensee's corrective actions for this fuel problem, this item is considered closed.

No violations or deviations were identified.

4. Monthly Surveillance Observation (61726)

For the below listed surveillance activities the inspectors verified one or more of the following: testing was performed in accordance with procedures; test instrumentation was calibrated; limiting conditions for operation were met; removal and restoration of the affected components were properly accomplished; test results conformed with technical specifications and procedure requirements and were reviewed by personnel other than the individual directing the test; and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

Surveillance Test No.	Activity
SVI-C51-T0027A	"APRM A Trips Channel Functional"
SVI-B21-T1402	"RWCU Isolation Logic Channel Functional Test"
SVI-P87-T9413	"Type C Local Leak Rate Test of 1P87 Penetration P413"

No violations or deviations were identified.

5. Monthly Maintenance Observation (62703)

Station maintenance activities of safety-related systems and components listed below were observed/reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with technical specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented.

Work requests were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which may affect system performance.

The following specific maintenance activities were observed:

W. O.	Subject
90-4985	Replaced Agastats for SVI-B21-T1402

90-165	Weld on Emergency Service Water [illegible] pipe support
89-6565	Replaced Division 3 diesel air start motor 1E22-C5000A
89-6566	Replaced Division 3 diesel air start motor 1E22-C5000B
89-6567	Replaced Division 3 diesel air start motor 1E22-C5000C
89-6568	Replaced Division 3 diesel air start motor 1E22-C5000D
90-4828	Lubricating oil heater (1R47-D004A) removed from Division 1 diesel
89-7129	Changed oil and filters for Division 1 diesel
89-7135	Replaced fuel injectors for Division 1 diesel

No violations or deviations were identified.

6. Operational Safety Verification (71707)

General

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during this inspection period. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified tracking of Limiting Conditions for Operation associated with affected components. Tours of the intermediate, auxiliary, reactor, and turbine buildings were conducted to observe plant equipment conditions including potential fire hazards, fluid leaks, and excessive vibrations, and to verify that maintenance requests had been initiated for certain pieces of equipment in need of maintenance. The inspectors by observation and direct interview verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls.

No violations or deviations were identified.

7. Engineered Safety Feature (ESF) Walkdown (71710)

During this inspection period, the inspectors performed a detailed walkdown of the accessible portions of "A" train of the Emergency Closed Cooling (ECC) System. The system walkdown was conducted using Valve Lineup Instruction (VLI)-P42, and the controlled Piping and Instrumentation Diagrams (P&IDs) for the ECC System.

During the walkdown, the licensee identified the "A" train as operable. The inspectors took into account that during the walkdown the "A" train was in various modes of operation and therefore in various valve lineups.

During the system walkdown, the inspectors directly observed equipment conditions to verify that hangers and supports were made up properly; appropriate levels of cleanliness were being maintained; piping insulation, heaters, and air circulation systems were installed and operational; valves in the system were installed in accordance with applicable P&IDs and did not exhibit gross packing leakage, bent stems, missing handwheels, or improper labeling; and, that major system components were properly labeled and exhibited no leakage. The inspectors verified that instrumentation associated with the system was properly installed, functioning, and that significant process parameter values were consistent with normal expected values. By direct visual observation or observation of remote position indication, the inspectors verified that valves in the system flow path were in the correct positions as required by the various modes of operation that were required; power was available to the valves; valves required to be locked in position were locked; and, that pipe caps and blank flanges were installed as required.

No violations or deviations were identified.

8. Onsite Followup of Events at Operating Power Reactors (93702)

a. General

The inspectors performed onsite followup activities for events which occurred during the inspection period. Followup inspection included one or more of the following: reviews of operating logs, procedures, and condition reports; direct observation of licensee actions; and interviews of licensee personnel. For each event, the inspectors reviewed one or more of the following: the sequence of actions; the functioning of safety systems required by plant conditions; licensee actions to verify consistency with plant procedures and license conditions; and verification of the nature of the event. Additionally, in some cases, the inspectors verified that licensee investigation had identified root causes of equipment malfunctions and/or personnel errors and were taking or had taken appropriate corrective actions. Details of the events and licensee corrective actions noted during the inspectors' followup are provided in Paragraph b. below.

b. Details

(1) Excessive Secondary Containment Bypass Leakage

On September 19, 1990, at about 11:00 a.m. (EDT), while the plant was in cold shutdown during the second refueling outage, the licensee determined that the Secondary Containment Bypass Leakage was greater than the 5051.74 standard cubic centimeters per minute (sccm) allowed by Technical Specification 3.6.1.2.d.

Licensee personnel determined by local leak rate tests (LLRTs) that the inboard and outboard containment isolation valves for the Reactor Recirculation and Reactor Water Cleanup sample lines for the Post Accident Sample System (PASS) leaked, resulting in containment penetration P413 being assigned an as-found leakage of about 4870 sccm. The Secondary Containment Bypass Leakage prior to testing these valves was 2380.62 sccm and after was 8250.62 sccm. Licensee personnel planned work orders to repair the valve and documented their internal investigation on condition report 90-260.

The licensee reported this event to the NRC Operations Center via the Emergency Notification System (ENS) about 1:00 p.m., September 19, 1990, in accordance with 10 CFR 50.72(b)2(i) and (iii). The inspectors will review the forthcoming LER during a future inspection period.

(2) Loss of Shutdown Cooling Caused By Division 2 Containment Isolation - Reportable Event Number 19579

On October 10, 1990, at 8:50 p.m. (EDT), while the plant was in the refueling mode during core alterations, a Division 2 containment isolation occurred resulting in the "A" Residual Heat Removal (RHR) subsystem, which was in the Shutdown Cooling Mode (SDCM), isolating. The "B" subsystem of RHR was unavailable for shutdown cooling. The containment isolation occurred when the "B" and "D" Electrical Protection Assemblies (EPA's) on the output of the "B" Reactor Protection System (RPS) Motor Generator (MG) opened for unknown reasons and de-energized the "B" RPS bus. The EPA's were essentially circuit breakers and had under-voltage, over-voltage and under-frequency trips. The Division 2 containment isolation shut the inboard containment isolation valve on the common suction line for subsystems "A" and "B" of the SDCM of RHR. Operators reset the EPA's, restored power to the "B" RPS MG bus, and restored RHR "A" Loop of shutdown cooling at 9:11 p.m. Graphs generated by the Emergency Response Information System computer indicated that reactor coolant temperature had remained stable at 75 degrees F during the loss of shutdown cooling. A half-scram on the "B" and "D" channels and an isolation of the Fuel Pool Cooling and Cleanup (FPCC) system had also been received. By 9:30 p.m. all systems had been returned to the normal shutdown lineup. Core alterations (fuel shuffle) had been halted after the containment isolation and were resumed at 9:30 p.m. The cause for the EPA's opening was under investigation by licensee personnel and will be documented under condition report 90-317.

The licensee reported this event to the NRC Operations Center via the ENS about 10:40 p.m. on October 10, 1990, as an Engineered Safety Feature actuation in accordance with 10 CFR 50.72(b)2(ii). The inspectors will review the forthcoming LER during a future inspection period.

In addition to the events described above, a drywell isolation valve, 1G61-F030, also failed to isolate as designed upon the unexpected loss of logic power. Licensee personnel identified that when the normally-energized Agastat EGP control relay in the valve control circuitry was deenergized that the core apparently stuck due to age-related thermal degradation and did not shift. The licensee indicated that about 750 normally-energized EGP or FGP Agastat relays are installed in safety-related circuits in the plant and that the fail-safe operation of these relays may be impaired due to this thermal end-of-life failure mode. About 250 of these relays perform a safety-related protective or control function (e.g. to cause a scram, a containment isolation, or an Emergency Core Cooling System to start and inject) and about 500 perform a safety-related alarm or indication function. At least two additional Agastat relay failures at Perry have been attributed to the end-of-life thermal-related phenomenon. One type of thermal-related failure mechanism for these relays had been previously established and documented in IE Information Notice 84-20, NUREG/CR-4715, and NUREG/CR-5181. The information Notice further stated that the life expectancy of the relays was 4.5 years. In 1985 at Perry, the majority of the currently operating EGP or FGP relays were installed to replace GP series relays which were original design. Therefore, most of the relays now in question have been operating for greater than 4.5 years. The licensee has never assigned a service life for these relays and had no program to replace these relays except when they failed. Further, the licensee also apparently has no program for replacing the relays that are not continuously energized prior to the end of their service life.

Licensee personnel have removed and examined about 56 Agastat relays and decided to replace all normally energized Agastat relays that perform a safety-related protective function (about 250) before restart from the second refueling outage.

Licensee personnel plan to replace all safety-related normally-energized Agastat relays that perform an indication or alarm function prior to July 1, 1991. Region III management has been and will continue to discuss with the licensee its investigation and replacement plans. The resident inspectors will review the forthcoming LER during a future inspection period.

(3) De-energization of Emergency Operations Facility (EOF) Reportable Event Numbers: 19600 and 19839

On October 13, 1990, while the plant was in a refueling outage, normal electrical power to the EOF was secured at about 5:20 a.m. (EDT) for about 24 hours while temporary power was connected. This transfer was necessitated by planned maintenance on the normal supply. The licensee reported its intention to perform this transfer to the NRC Operations Center via the ENS about 12:30 a.m. (EDT), on October 13, 1990, in accordance with 10 CFR 50(b)(1)(v).

On November 11, 1990, at about 3 p.m. (EST), while the plant was in a refueling outage, temporary power was secured to the EOF for about 4 hours, while normal power was re-connected, after completion of planned maintenance on the normal supply. The licensee reported its intention to perform this transfer to the NRC Operations Center via the ENS about 3 p.m. (EST), on November 11, 1990, in accordance with 10 CFR 50(b)(1)(v).

The NRC had no concerns with the above-mentioned activities.

(4) Excessive Bird Impaction
Reportable Event Number: 19768

On November 2, 1990, at 10:00 a.m. (EST), while the plant was in a refueling outage with the cooling tower system drained for maintenance, licensee personnel found the carcasses of 54 small birds of various species in the Unit 1 cooling tower basin. On October 29, 1990, when the sludge removal from the basin was completed, no bird carcasses were found. The cause of the excessive bird impaction was unknown and was under investigation by the licensee.

The licensee reported this excessive bird impaction to the NRC Operations Center via the ENS about 5:00 p.m. the same day, and within the 24 hours, as specified in the Perry Operating License, Appendix B, Environmental Protection Plan (Nonradiological), Section 4.1. The inspectors will review the forthcoming written report for this event during a future inspection period.

(5) Combined Leakage Rate Greater Than 0.60 La

Reportable Event Number: 19869

On November 15, 1990, at about 4:30 p.m. (EST), during the second refueling outage, licensee personnel determined that the Primary Containment Leakage Rate exceeded the 0.60 La combined leakage rate required by Technical Specification 3.6.1.2.b. This occurred when the inboard primary containment isolation check valve 1C11-F122 (for the control rod drive hydraulic system) was determined to have excessive leakage (127.0 standard liters per minute (SLM) +6.0 SLM). This was the fourth consecutive failure of this valve during LLRT testing.

The licensee reported this event to the NRC Operations Center via the ENS at about 10:28 a.m. on November 15, 1990, in accordance with 10 CFR 50.72(b)(2)(i) and (iii). The inspectors will review the forthcoming LER during a future inspection period.

9. Plant Status Meeting (30702)

NRC Management met with CEI management on October 17, 1990, at the Perry plant, and discussed: the status of the second refueling outage which started September 7, 1990; repairs and design modifications to the Main Steam Isolation Valves and the hydraulic control unit solenoid pilot valves to prevent future failures; and events of interest since the last plant status meeting of August 7, 1990.

NRC management acknowledged the licensee's plans and current plant status.

10. 'ALP MEETING

On October 30, 1990, from about 1 p.m. (EDT) to 3 p.m., NRC management (notably the Director of the Division of Reactor Projects, Hubert J. Miller) presented the results of Report No. 50-440/90001(DRP), Perry's tenth Systematic Assessment of Licensee Performance (SALP) to CEI's management (notably the Chairman of Centerior Energy Corporation, Richard A. Miller) during a meeting attended by some members of the public and local media.

11. Exit Interviews

The inspectors met with the licensee representatives denoted in Paragraph 1 throughout the inspection period and on November 16, 1990. The inspector summarized the scope and results of the inspection and discussed the likely content of the inspection report. The licensee did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.

During the report period, the inspectors attended the following exit interview:

Inspector	Exit Date
Maintenance Inspection Team	October 12, 1990