U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Inspection Report 50-244/92-20 **License: DPR-18**

Facility: R. E. Ginna Nuclear Power Plant
Rochester Gas and Electric Corporation (RG&E)

Inspection: December 19, 1992 through January 26, 1993

Inspectors: T. A. Moslak, Senior Resident Inspector, Ginna
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Approved by: W. J. Lazarus, Chief, Reactor Projects Section 3B 2/9/93 Date

INSPECTION SCOPE

Plant operations, radiological controls, maintenance/surveillance, security, engineering/technical support, and safety assessment/quality verification.

INSPECTION OVERVIEW

Plant Operations: A 20 percent turbine runback occurred due to temporary loss of safety grade buses following loss of an offsite electrical supply circuit. Good procedural adherence was observed during plant power changes in support of main condenser maintenance.

Radiological Controls: Radiological controls were conscientiously implemented. Preparations were in progress for offsite transport of irradiated reactor fuel samples.

Maintenance/Surveillance: Timely repair of a nitrogen system relief valve precluded impact on plant operations. The maintenance was adequately controlled.

Security: Security measures were effectively implemented.

Engineering/Technical Support: Procedural control of minor valve alignments remains a concern and is being systematically addressed by the licensee.

Safety Assessment/Quality Verification: The program for cold weather preparation and inspection was examined and found to be adequate.

Evaluation of Changes to Site Environs: The UFSAR adequately addressed current safety hazards around the site. Although the regulatory requirements were met, the licensee did take action to improve the timeliness of communications between the Nuclear Safety and Licensing Department and those departments performing evaluations addressing changes to environs surrounding the site.

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DETAILS

1.0 PLANT OPERATIONS (71707)

1.1 Operational Experiences

The plant operated at 98 percent power through the majority of the inspection period. On December 24, 1992, loss of one of the two offsite electrical power supply circuits resulted in a 20 percent turbine runback when two of the four safety grade 480 volt buses were momentarily deenergized. On January 19, 1993, power was reduced to 48 percent to support plugging main condenser circulating water tubes due to leakage. In both cases, full power operations were restored within one day.

1.2 Control of Operations

Overall, the inspectors found the R. E. Ginna Nuclear Power plant to be operated safely. Control room staffing was as required. Operators exercised control over access to the control room. Shift supervisors consistently maintained authority over activities and provided detailed turnover briefings to relief crews. Operators adhered to approved procedures and were knowledgeable of off-normal plant conditions. The inspectors reviewed control room log books for activities and trends, observed recorder traces for abnormalities, assessed compliance with Technical Specifications, and verified equipment availability was consistent with the requirements for existing plant conditions. During normal work hours and on backshifts, accessible areas of the plant were toured. No operational inadequacies or concerns were identified.

1.3 Turbine Runback Due To Loss of Offsite Power Supply

Normal and emergency electrical power for the Ginna plant is provided by two independent offsite supply lines. These 34.5 kilovolt supply lines, circuits 751 and 767, normally supply station auxiliary transformers 12A and 12B, respectively; however, both circuits are capable of independently supplying either or both of the auxiliary transformers. Along with supplying all normal site loads, these transformers each supply two safety grade (1E) electrical buses (buses 14 and 18 from auxiliary transformer 12A, and buses 16 and 17 from auxiliary transformer 12B) through associated 480 volt stepdown transformers. Two emergency diesel generators (EDGs) serve as backup 1E power sources for the auxiliary transformers. The 1E electrical buses are safety significant in that they supply power to virtually all reactor safety/accident mitigation equipment and instrumentation.

At 4:35 AM on December 24, 1992, circuit 751 lost power, resulting in the loss of 1E buses 14 and 18. Redundant equipment, powered from the other 1E electrical train (buses 16 and 17) started as required, and the "A" EDG started automatically to reenergize the buses within 10 seconds. The brief interruption of power to the two 1E buses nonetheless produced a 20 percent turbine runback. This was a result of the reactor protection system design and the arrangement of power supplies to the power range nuclear instruments (PRNIs). Specifically:

- The reactor protection system uses the four PRNIs for detection of a dropped control rod (that is, a fully withdrawn control rod that, due to electrical or mechanical malfunction, is inadvertently released by its drive mechanism and inserted into the core; continued full power operation in this condition is undesirable because the resultant neutron flux redistribution may result in excessive power generation (and ultimately, fuel damage) in localized portions of the core). A power level indication from any one of the PRNIs that is sufficiently lower than the remaining three generates a rod-dropped signal. In response, the reactor protection system initiates a 20 percent turbine runback by reducing turbine load at 200 percent per minute for six seconds.

- One bus in each of the two 1E electrical trains (bus 14 in the "A" train and bus 16 in the "B" train) normally supply power to two PRNIs. All four PRNIs can be powered by either 1E electrical train, however, only two are protected against loss of electrical power by automatic bus transfer devices. Therefore, loss of power to a 1E electrical train will result in loss of one PRNI channel until either 1) its power supply is manually transferred to the other 1E train, or 2) normal or emergency power is fully restored to the deenergized train.

- The transition of a PRNI from energized to deenergized while the reactor is at power appears, to the reactor protection system, as a rapid power decrease and is thus processed as a dropped control rod. Therefore, a 20 percent turbine runback is an expected (although unnecessary) response of the reactor protection system to loss of either 1E electrical train.

Following the turbine runback, operators stabilized plant conditions at approximately 77 percent reactor power. Buses 14 and 18 were transferred to circuit 767 and the "A" EDG was returned to its normal standby condition. Generator load increase was commenced and the plant was restored to full power operation.

Licensee investigation revealed that the cause of the loss of power to circuit 751 was a short circuit to ground that had occurred between the offsite supply station (station 204) and the site; this had caused an instantaneous overcurrent trip of the circuit 751 supply breaker at station 204. Although fault locator monitoring equipment had been in service at the time, visual inspection of the overhead line at the indicated fault location identified no evidence of damage. The cause of the short circuit was postulated to be that a tree branch had come into momentary contact with the overhead line as a result of high wind. Following additional inspection and testing, circuit 751 was returned to service on December 26, 1992. Pending further evaluation, however, the licensee elected to maintain offsite electrical distribution aligned with circuit 767 supplying all loads.

Technical specification (TS) 3.7.2.1.b requires that both circuits 751 and 767 be operable and supply their respective auxiliary transformers prior to the plant being taken above 350°F. However, TS 3.7.2.2.a states that operation above 350°F may continue with one offsite

source inoperable, provided all remaining conditions of TS 3.7.2.1 are met. This allowance is made because the original plant design utilized only one source of offsite power (circuit 767); in that the safety analysis was conducted on this basis, the subsequent addition of a second offsite power source (circuit 751) did not necessitate development of a more restrictive specification for power operations. Nonetheless, the requirement to have both circuits in operation prior to exceeding 350°F is based on establishing the most reliable configuration prior to startup; although allowed, operation with a single offsite source of power is now the off-normal case.

At the close of the inspection period, the licensee continued to operate with circuit 767 supplying all offsite power and circuit 751 available but not in service. Additionally, location of the fault to ground on circuit 751 had been confirmed to have been in the overhead portion of the circuit (as originally indicated by the fault monitoring equipment). The licensee is conducting an engineering review to determine the optimum alignment of the offsite power supplies. In light of the existing TS allowance for unrestricted power operations in the present configuration, the inspector considered this to be a conservative approach.

1.4 Power Reduction Due To Main Condenser Circulating Water Tube Leak

As the result of routine tracer gas monitoring for main condenser circulating water tube leakage, chemistry department personnel identified minor leakage in the 1A2 waterbox. Several days later, on January 19, 1993, the leak rate had increased to the point that impurities were detectable in the condensate and steam generators. The concentration of impurities (chloride and sulfate), along with cation conductivity, indicated a leak rate of approximately 1.4 gallons per minute. Placing the 1A2 waterbox out of service for repairs would require that power be reduced to less than 50 percent. Based on 1) the relatively low leak rate and 2) impurity concentrations in the steam generator not rapidly increasing, and contingent on continuation of these trends, the licensee decided to wait until the evening (when the grid power demand would be lower) to reduce plant power.

At 7:00 PM on January 19, 1993, the licensee commenced power reduction at 10 percent per hour. Power was stabilized at 48 percent early the following morning and the 1A2 waterbox was isolated for repairs. A total of eight circulating water tubes were determined to be leaking and were removed from service by plugging. In conjunction with this work, the licensee made further use of the period of reduced power operation to repair a leak from the "B" main feedwater pump (MFP) suction relief valve. Following the completion of maintenance, power escalation was commenced at 8:54 AM. The plant returned to full power operation at 3:06 PM, January 20, 1993.

The inspector concluded that operations to support maintenance on the 1A2 condenser waterbox and the "B" MFP were well planned and controlled. The inspector observed portions of the power reduction, conducted in accordance with operations (O) procedure O-5.1, "Load Reductions," and of the power escalation, conducted in accordance with O-5.2, "Load Increases." Good procedural adherence was observed in both cases.

1.5 Licensee Action on Previous Inspection Findings

1.5.1 (Closed) Inspector Follow Item (50-244/92-01-01) Verification of Plant Records

The inspector reviewed licensee actions regarding improving auxiliary operator (AO) watchstanding practices and enhancing individual accountability for rounds performed. In response to shortcomings identified in operations procedure O-6, "Operations and Process Monitoring," site management developed and implemented a separate procedure delineating AO responsibilities. The inspector reviewed the new procedure, O-6.1, "Auxiliary Operator Rounds and Log Sheets," revision 0, effective December 2, 1992, and determined that strong administrative controls are in effect that specifically detail AO round frequencies, round assignment areas, round duration, accountability for actions, and management oversight responsibilities. The inspector had no additional questions on this matter.

2.0 RADIOLOGICAL CONTROLS (71707)

2.1 Routine Observations

The inspectors periodically confirmed that radiation work permits were effectively implemented, dosimetry was correctly worn in controlled areas and dosimeter readings were accurately recorded, access to high radiation areas was adequately controlled, and postings and labeling were in compliance with procedures and regulations. Through observations of ongoing activities and discussions with plant personnel, the inspectors concluded that radiological controls were conscientiously implemented.

2.2 Preparations For Shipment of Irradiated Reactor Fuel

As discussed in inspection report 50-244/92-15, the licensee has prepared selected fuel rods from two irradiated test fuel assemblies for offsite laboratory examination. On January 19, 1993, the inspector observed operations to transfer these fuel rods into a shipping cask, and subsequent preparation of the cask for transport. Results of this inspection are presented in inspection report 50-244/93-01. At the close of the inspection period, the licensee had completed preparation of the cask for transport. Shipment of the cask will be examined in a future inspection.

3.0 MAINTENANCE/SURVEILLANCE (62703, 61726)

3.1 Corrective Maintenance

3.1.1 Repair of Nitrogen Inlet to Accumulators Relief Valve

On the evening of January 25, 1993, the nitrogen inlet to accumulators relief valve, V-8621, lifted while attempting to adjust pressure in the "B" overpressure protection accumulator. The cause was apparently a pressure transient that occurred during system alignment in

preparation for charging nitrogen. In any case, operators subsequently found that V-8621 continued to relieve with the system at normal operating pressure. Due to system configuration, the valve cannot be isolated while the nitrogen header is in service; therefore, charging nitrogen to the overpressure protection and safety injection (SI) accumulators would not be possible until the valve was repaired. While not an immediate concern with respect to the overpressure protection accumulators (which are only in use during cold shutdown), inability to make up for gradual nitrogen leakage could compromise SI accumulator operability.

Work to repair V-8621 commenced on the morning of January 26, 1993. Following removal and disassembly, the cause of failure was found to be a dislodged O-ring. The valve was reassembled using a new O-ring and reinstalled in the nitrogen charging system. Following completion of an operational leak check, the system was returned to service on the evening of January 26, 1993.

The inspector examined the work site following valve removal. While adequate, the inspector considered that precautions against entry of foreign material through the disconnected piping could have been more secure. This was discussed with the licensee for information. Additionally, the inspector noted that an electrical conduit to one of the solenoid operated instrument air valve (SOV-14280S) associated with the containment depressurization valves (AOV-7971) had been pulled out of a connection box which was located in close proximity to the work site; the condition of the associated wiring could not be readily determined by visual inspection. When informed, the shift supervisor promptly cycled AOV-7971 to verify its operability. A work request was subsequently submitted to reattach the conduit to the connecting box.

Through review of the work package (Work Order 9300138) and system isolation, inspection of the work site, and discussions with personnel, the inspector concluded that the repair of V-8621 was adequately controlled. The inspector had no additional concerns.

3.2 Surveillance Observations

Inspectors observed portions of surveillances to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to Limiting Conditions for Operation (LCOs), and correct system restoration following testing. The following surveillances were observed:

- Performance test (PT)-2.2M, "Residual Heat Removal System - Monthly", revision 1, dated June 8, 1990, observed January 14, 1993

- PT-12.2, "Emergency Diesel Generator 1B", revision 71, dated April 17, 1992, observed January 15, 1993

-- On data sheet 5, "Local Readings," the technician records the 16 cylinder exhaust pyrometer readings, and then transcribes the highest and lowest readings for determination of maximum differential temperature. In this case, the lowest recorded temperature was 250°F, but the value transcribed for determining differential temperature was 260°F. This error did not affect the acceptability of the results, and was noted and corrected during subsequent supervisory review.

- PT-32B, "Reactor Trip Breaker Testing - "B" Train", revision 13, dated October 30, 1992, observed January 25, 1993

The inspector determined through observing this testing that Results and Test personnel adhered to procedures, equipment operating parameters met acceptance criteria, and redundant equipment was available for emergency operation.

4.0 SECURITY (71707)

4.1 Routine Observations

During this inspection period, the resident inspectors verified that x-ray machines and metal and explosive detectors were operable, protected area and vital area barriers were well maintained, personnel were properly badged for unescorted or escorted access, and compensatory measures were implemented when necessary. Adequate compensatory measures were provided to support ongoing site security upgrade modifications. No unacceptable conditions were identified.

5.0 ENGINEERING/TECHNICAL SUPPORT (71707, 92701)

5.1 Procedural Control Of Safety System Valve Alignments

As part of a routine safety inspection, the inspector conducted a walkdown of the residual heat removal (RHR) system to verify system operability. In light of problems noted during the previous inspection period with control of valve alignments for system components associated with testing, the inspector expanded the scope of the inspection beyond the major flow paths to include such components. A total of six valves were found to be out of their normal positions as specified on the RHR system piping and instrumentation diagram (P&ID), drawing number 33013-1247. All of the out-of-position valves were associated with detectors that are used only for testing, and thus had no effect on system operability. Additionally, all of the valves in question were verified to be in positions established by applicable procedures. In that, prior to these findings, action had already been initiated by the licensee to resolve the disagreements between the applicable procedures and the P&ID, the inspector considered that questions regarding RHR valve positions had been adequately resolved.

The inspector noted following additional discrepancies between the RHR system P&ID and actual plant conditions:

-- The P&ID showed temperature indicators TI-680 and -681 at the RHR pump suctions; actually installed were temperature elements (for remote indication), labeled TE-684A and B.

-- The P&ID showed the RHR pump discharge flow elements as FE-683A and -683B; the labels on these components indicated FE-670 and -671.

-- A valve, installed downstream of the RHR header to loop "B" outer sample isolation valve (2780A), was not labeled and was not shown on the P&ID.

-- The P&ID showed the RHR heat exchanger room wall to be between the "B" heat exchanger and valve 697B; the wall is actually on the opposite side of V-697B.

The licensee was informed of these findings and corrective action was expeditiously initiated for all noted discrepancies.

On January 12, 1993, while performing PT-16M-B, "Auxiliary Feedwater Pump B - Monthly," the technician found valve 4308B (root valve to AFW pump B discharge pressure gauge) to be open whereas the procedure indicated that it should be shut. This valve isolates a pressure gauge which is used only for testing; therefore, its position had no effect on system operability. Investigation determined the cause to be that the gauge had been calibrated after the previous completion of PT-16M-B, and that the calibration procedure had left the valve open.

In summary, control of minor valve alignments remains a concern. Inconsistencies were noted between 1) the initial system lineup procedures and subsequently used testing or operating procedures, and 2) P&ID drawings and procedures. The inspector will continue to track the licensee's corrective actions as coordinated by corrective action report (CAR) 2069 and will further examine the issue in a future inspection.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (90712, 90713, 92701, 40500)

6.1 Periodic Reports

Periodic reports submitted by the licensee pursuant to Technical Specification 6.9.1 were reviewed. Inspectors verified that the reports contained information required by the NRC, that test results and/or supporting information were consistent with design predictions and performance specifications, and that reported information was accurate. The following report was reviewed:

- Monthly Operating Report for December 1992

No unacceptable conditions were identified.

6.2 Winterizing Inspection

The inspector reviewed the programmatic, maintenance, and operational aspects of the licensee's program of protective measures for extreme cold weather. Maintenance procedure M-1306.1, "Ginna Station, Maintenance Department, Winterizing Inspection Program," revision 5, effective August 7, 1992, is the controlling procedure for the cold weather protection program. Areas inspected per this instruction include heat trace circuits, piping insulation, motor winterizing, window and ventilation supply openings, screenhouse overflow weirs, area heaters, and equipment in the cooling water inlet flowpath; specific equipment and location identified as susceptible to freezing are identified under each area. The inspector reviewed the completed M-1306.1 for 1992. Sixteen work requests had been generated as a result of the winterizing inspections, the majority of which were for minor deficiencies, such as insulation improvements on service water system piping and area heater repairs.

Operations department responsibility within the cold weather protection program is specified in Administrative (A) Procedure A-54.4.1, "Cold Weather Walkdown Procedure," revision 14, effective November 14, 1992. On January 25, 1993, the inspector performed a plant cold weather walkdown in accordance with this procedure and compared the results against the two most recently completed licensee walkdowns. No significant operational deficiencies were noted. The inspector noted some minor administrative weaknesses which were discussed with the licensee and have since been satisfactorily resolved.

In summary, the cold weather protection program at Ginna was reviewed and found to be of adequate scope and effectively implemented.

7.0 REVIEW OF LICENSEE EVALUATIONS REGARDING CHANGES TO THE ENVIRONS AROUND LICENSED REACTOR FACILITIES (30702B)

(Closed) TI 2515/112: This inspection was conducted to determine if the licensee's programs are adequate for evaluating public health and safety issues resulting from changes in population distribution or through the introduction of new industrial, military, or transportation hazards near the site.

During this inspection, the following documents were reviewed:

-- Updated Final Safety Analysis Report (UFSAR) Chapters 2, 3, and 13

-- License Amendment Request for Change of License Expiration Date, dated October 5, 1989.

-- NUREG-0944, Safety Evaluation Report related to the full term operating license for R. E. Ginna Nuclear Power Plant, dated October 14, 1983, and supplement.

-- Letter from Dennis M. Crutchfield (NRC) to John E. Maier (RG&E) dated July 17, 1981 regarding Systematic Evaluation Program (SEP) Topic II.1.A, "Exclusion Area Authority and Control."

-- Letter from Dennis M. Crutchfield (NRC) to John E. Maier (RG&E) dated July 21, 1981 regarding SEP Topics II-1.B, "Population Distribution" and III-4.D, "Site Proximity Missiles."

-- Letter from Dennis M. Crutchfield (NRC) to John E. Maier (RG&E) dated September 29, 1981 regarding SEP Topic II-1.C, "Potential Hazards Due to Nearby Transportation, Institutional, Industrial, and Military Facilities."

-- Evacuation Travel Time Estimates for the Robert E. Ginna Nuclear Power Station Emergency Planning Zone, dated September 1992, prepared by Parsons Brinkerhoff-FG, Inc.

-- Community Data Statistics compiled by the town of Ontario, New York, for September, 1992.

-- Semiannual Radioactive Effluent Release Reports for 1990 and 1991.

-- Chemistry-Environmental (CE) Procedure CE-9, Land Use Census, Revision 4.

-- Emergency Plan Implementing Procedure (EPIP) 5-6, Annual Review of Nuclear Emergency Response Plan (NERP), Revision 0.

-- Administrative Procedure-(A)-65, Preparation, Review, and Approval of Changes to the Updated Final Safety Analysis Report.

Through review of the listed documents and through discussions with licensee personnel and local community representatives, the inspector found that the applicable chapters in the USFAR describing the local area around the reactor site were periodically updated with new information when appropriate. In support of the October 5, 1989, application for an extension of the expiration date for the Ginna operating license, RG&E obtained 1984 population data for the thirteen county area included within a 50 mile radius of the plant. The population in this area had slightly increased (about 3% overall) since 1970 which was below RG&E initial estimates. Wayne County, in which the site is located, continues to be a sparsely populated, rural area with little industrial activity. There are no substantial population centers, industrial complexes, transportation arteries, parks or other recreational facilities near the plant. The use of land within a 5 mile radius surrounding the plant is checked annually by the licensee, through implementation of procedure CE-9, "Land Use

Survey," to determine if any changes have occurred, as required by Technical Specification 3.16 and 4.10.2. The most recent annual survey conducted by the site environmental department, concluded that there were no significant changes in land usage.

The inspector toured the vicinity surrounding the site. No new safety considerations were identified which were not already addressed in the UFSAR. Several small businesses, private homes, and a small scale (22 lot) housing development were recently constructed within a 5 mile radius. Through discussions with local planning officials, the inspector determined that no large scale housing developments or large industrial projects were anticipated for the future.

In addition to reviewing the activities of the site environmental department, other site and corporate departments were contacted to determine how the licensee remained cognizant of changes to the environs around the facility.

The RG&E Emergency Preparedness Department representatives schedule frequent meetings with Monroe and Wayne County emergency management representatives. These meetings primarily focus on emergency plan implementation, but changes to the areas surrounding the plant that could impact the emergency plan and related evacuation planning are discussed. Additionally, to comply with the recommendations of NUREG-0654/FEMA REP-1, "Criteria for Preparations and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," RG&E, through Parsons Brinkerhoff-FG, Inc., prepared updated evacuation travel time estimates in September 1992. This report, an update of an evacuation time estimate report prepared in December 1986, incorporated 1990 Census Data for the population within the 10 mile radius of the Emergency Planning Zone. The data compiled in this study will be incorporated in the updated RG&E Nuclear Emergency Response Plan (NERP) following review and approval of the revised NERP by the site Plant Operations Review Committee (PORC) and the Nuclear Safety Audit and Review Board (NSARB). This mandatory review is performed in accordance with EPIP 5-6, "Annual Review of Nuclear Emergency Response Plan (NERP)." Any significant changes in demographics and industrial transient population identified in this study are evaluated in the review cycle by the responsible departments within the RG&E organization and the UFSAR is revised accordingly.

In reviewing the licensee's procedures that directly address evaluating changes to the environs surrounding the facility, specifically CE-9 and EPIP 5-6, the inspector noted that there is no direct formal communication with the licensee's Nuclear Safety and Licensing (NSL) Department to inform NSL that a change to the UFSAR may be warranted following completion of these procedures. Presently, it is left to the judgement of the individual department implementing their respective procedures to make this determination. Licensee representatives acknowledge this procedural shortcoming and are revising the relevant procedure to assure that NSL is promptly informed of data that could result in UFSAR changes.

Upon identification of an issue that could potentially result in a change to the UFSAR, plant personnel would initiate the process for evaluation and UFSAR revision through use of A-65, "Preparation, Review, and Approval of changes to the Updated Final Safety Analysis Report." Procedure A-65 is generally implemented during procedure changes of by plant modifications which require reviews specified by 10 CFR 50.59. Reviews which identify the need for UFSAR revisions are forwarded to NSL for processing. Proposed UFSAR revisions are then compiled in the UFSAR revision and submitted to the NRC.

The inspector reviewed pertinent sections of chapters 2, 3, and 13 of the UFSAR relevant to the licensee assessing changes to plant environs. RG&E has periodically updated the UFSAR with additional information in support of license amendment requests, changes to plant characteristics and changes in emergency planning measures.

In conclusion, the inspector found that the applicable chapters in the UFSAR addressed the pertinent safety considerations around the site. While regulatory requirements were met, improvement could be made in communicating data gathered by the site environmental section and emergency preparedness departments to the licensee's nuclear safety and licensing organization to facilitate a determination of revising appropriate sections of the UFSAR.

8.0 ADMINISTRATIVE (71707, 30702, 94600)

8.1 Backshift and Deep Backshift Inspection

During this inspection period, a backshift inspection was conducted on January 19, 1993. Deep backshift inspections were conducted on January 7 and 22, 1993.

8.2 Exit Meetings

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of inspections. The exit meeting for inspection report 50-244/93-01 (radiological waste processing and transportation inspection, conducted January 19-22, 1993) was held by Mr. James Noggle on January 22, 1993. The exit meeting regarding licensee evaluations of changes to the environs was held by Mr. Thomas Moslak on January 22, 1993. The final exit meeting for this inspection report was held on January 27, 1993.