U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-440/95009

FACILITY

Perry Nuclear Power Plant, Unit 1

License No. NPF-58

LICENSEE

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

DATES

October 21 through December 1, 1995

INSPECTORS

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APPROVED BY

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Reactor Projects Branch 2

AREAS INSPECTED

A routine announced integrated inspection of operations, engineering, maintenance, and plant support was performed. Safety assessment and quality verification activities were routinely evaluated. Follow-up inspection was performed for non-routine events and for certain previously identified items.

RESULTS

Assessment of Performance

OPERATIONS: Overall, plant operations continued to be conducted well. This was demonstrated during a shutdown, startup, and control rod manipulations for leaking fuel localization. Oral communications within operations remained excellent. Prompt identification and correction of a tagging error prevented serious personnel injury. A few other minor personnel errors were again identified this report period, though the significance of the personnel errors declined.

MAINTENANCE: Overall, observed work was performed in a thorough and professional manner. However, several personnel errors were identified which had minor impact on plant operations. Planning and work coordination weaknesses were also evident on occasion. Other identified personnel errors had no impact on plant operation because they were promptly detected by other organizations. One of these, a petcock that was not closed, was a Non-Cited Violation. An example of poor communications with operations was also identified.

ENGINEERING: Good support for maintenance and chemistry groups was provided by engineering during this inspection period. The licensee's Engineering and Technical Support Self-Assessment audit was thorough and effective. This audit identified significant improvements in the quality of design change packages (DCP's) and safety evaluations that were verified by the NRC inspectors. Improvements were also made in the documented basis for temporary modifications and a lower threshold for implementing the corrective action process and reductions in engineering backlogs. However, continued weaknesses in design verifications and some root cause and corrective action weaknesses for equipment failures and anomalies, such as the drop in reactor vessel level when aligning the RHR system for shutdown cooling mode, existed.

PLANT SUPPORT: Overall, plant support activities were good during the inspection period. Good coordination and communications were evidenced between chemistry and radiation protection, and support to engineering for the identification and evaluation of a nuclear fuel leak. Stopping work on two projects that had exceeded the radiation exposure dose estimates was considered good. Good fire protection response was noted to a fire in an emergency lighting panel. However, there was evidence of some minor decline in housekeeping.

SAFETY ASSESSMENT AND QUALITY VERIFICATION: Overall, Quality Assurance and self-assessment activities had a positive impact on station performance. However, problems remained with implementation of the corrective action program, three of which were examples of a violation. Quality assurance (QA) audits and surveillance were effective in identifying areas for improvement and there was excellent QA followup.

Summary of Open Items
Violation: Identified in Section 5.1
Unresolved Items: Not identified in this report
Inspector Follow-up Items: Not identified in this report
Non-Cited Violation: Identified in Section 2.3.

<u>INSPECTION DETAILS</u>

1.0 OPERATIONS

NRC Inspection Procedures 71707, 71500, and 92901 were used to perform an inspection of plant operations activities. No violations or deviations were identified.

1.1 Operations Summary

The plant was operating at full power at the beginning of the inspection and operated at various power levels throughout the remainder of the inspection period. On November 3, 1995, power was reduced to about 63 percent to facilitate identification of a leaking fuel assembly. The plant was restored to full power on November 8, 1995. On November 11, 1995, the licensee conducted a controlled shutdown and cooldown to evaluate failures in both lower drywell cooler fans. Both fans were replaced and the plant was restarted on November 18, 1995. The plant was restored to full power on November 21, 1995. On November 28, 1995, the plant began "coastdown" to the refueling outage and was at approximately 98 percent power at the end of the inspection period.

1.2 Operator Control of Routine Plant Operations Was Good

The inspectors observed routine plant operations and concluded that overall performance was good. Although there were no significant transients during the inspection period there were several major plant maneuvers and minor transients which were handled well. Oral communications by the operators continued to be excellent. However, a licensed operator unintentionally started a stator water cooling pump instead of an electro-hydraulic control system pump and another licensed operator shifted an intermediate neutron monitor range down instead of up during a power increase. These errors had no impact on plant operations, but they demonstrated the additional need for individual attention to detail.

1.3 Operator Response to Drywell Fan Failures Was Good

On November 9, the inspectors observed that the control room had received a 480V Bus Ground Annunciator Alarm for one of two lower drywell area vaneaxial cooling fans. A High Vibration Annunciator had been alarming intermittently on the fan earlier. The standby fan had started, but annunciator alarms indicated air flow was low with intermittent high fan vibration alarms. The operator's response to the indications was prompt and appropriate. Troubleshooting found the fan was drawing only half its expected electric current. Air temperature began to rise in the lower drywell area. The fans are not safety-related and are used to maintain desirable air temperatures in the drywell.

About 3 hours after the first fan had tripped, the second fan also tripped. Both fan power circuits had blown main line fuses and opened thermal overloads. Temperature in the lower drywell area stabilized at about 224 degrees F. Although a design engineering analysis (further discussed in Section 3.5) concluded that continued plant operation was acceptable, plant management conservatively decided to shut down the plant and repair the fans (further discussed in Section 2.1).

1.4 Safety Tagging Errors Recur

The licensee recently revised its safety tagging program to reduce tagging errors. Since this program revision, performance improved in this area. However, on November 17, 1995, an unlicensed operator mistakenly closed an electrical disconnect for a nonsafety-related fan with an active tagout. He intended to close the disconnect for another fan so that its direction of rotation could be checked. The operator promptly identified and reported the error and no one was hurt. Such an error could lead to serious injury or death of plant personnel. There were a few other less significant tagging errors during this inspection period. The licensee initiated appropriate corrective actions. Adequate emphasis on proper safety tagging is especially important now because there will be increased tagging activities during the refueling outage which begins in January 1996.

2.0 MAINTENANCE AND SURVEILLANCE

NRC Inspection Procedures 62703, 61726, and 92902 were used to perform an inspection of maintenance and testing activities. One example of a corrective action violation was identified. Three examples of this violation are consolidated in Section 5.1. No deviations were identified.

2.1 Drywell Cooler Fan Forced Outage

Two lower drywell area ventilation fans (see Section 1.3) were replaced with spare fans. The licensee's preliminary root cause evaluation for the first lower drywell area fan failure was that the most likely cause was increased radial bearing play that allowed the fan blades to contact the housing, resulting in the motor's rotor and stator coming into contact with each other, causing a direct electrical short to ground. Although this fan had an intermittent high vibration alarm for some time prior to failure, the licensee had taken local vibration readings that indicated vibration was within acceptable limits. The inspectors also reviewed lubrication records for this fan, which showed that it had been regularly lubricated. Earlier the licensee had discussed lubrication intervals with the fan vendor and determined that they could increase the lubrication interval from 6 months (recommended in vendor manual) to 18 months. An engineering evaluation of the vibration switches indicated that the switches were not located or designed to provide reliable indication of imminent fan failure. The licensee did not identify any immediate remedy for this design weakness.

The second fan failure was attributed to loss of the fan spinner (a circular metal cone upstream and over the center of the fan blades) retaining bolts, which allowed the spinner to be drawn into contact with the blades. The fan blades were found separated from the hub. Only minor collateral damage was identified and the licensee verified that the fan design was adequate to prevent missile damage to other safety-related equipment. The loss of the blades caused a loss of cooling to the motor and subsequent motor failure. The licensee checked the spinner retaining bolts on the other four drywell cooling fans and found some with lower than required torque and no evidence of thread locking compound. Thread locking compound was applied to those bolts and they were torqued to the proper value.

The inspectors verified that the licensee had noted problems with coordination and work control during the outage, and was planning to evaluate the outage for lessons learned. A maintenance worker wrote a potential issues form (PIF) that identified some of the coordination problems as well as other problems that occurred during the outage. This will be evaluated after the licensees planned critique.

2.2 Installation Error Delays Operability of Safety System

Completion of a reactor core isolation cooling (RCIC) system outage was delayed by about 8 hours because a solenoid valve for a containment and drywell purge system (M14) valve had been installed backwards with an improperly installed compression fitting during maintenance. The solenoid valve was installed some time after October 31, 1995. The licensee identified both problems on November 2, 1995, prior to returning the solenoid valve to service. The RCIC could not be run for post maintenance testing without M14 operating due to the potential loss of access to containment as radioactive noble gas concentrations increased. The compression fitting compression nut had been installed without internal ferrules and tightened up against the body of the fitting. This was a fundamental error in fitting assembly because a properly assembled fitting would have had a clearly visible gap between the compression nut and the fitting. This was a recurrence of an improper fitting assembly that had been identified by the NRC on an emergency diesel generator on April 1, 1994. The licensee's failure to implement corrective actions sufficient to prevent recurrence is an example of a violation and is discussed further in Section 5.1 along with other examples of corrective action problems.

2.3 Poor Control of Plant Equipment

The licensee identified a drain valve in an intermediate position that should have been closed. The valve was associated with a filter drain on a subloop of one of two hydraulic power units for the recirculation flow control valves. Given the location and orientation of the valve, the licensee suspected the valve had been "bumped" during work on the Inclined Fuel Transfer System. The valve was closed and reoriented to minimize the potential for recurrence.

Another valve was also identified by operations as mispositioned after maintenance activities on the Division II Emergency Diesel Generator (EDG). The valve was a small petcock used to drain an EDG day tank fuel oil filter casing. A nonlicensed operator noticed fuel draining from the petcock as he opened valves that had been closed to isolate the filter casing for maintenance. Maintenance personnel had not adequately checked the position of the petcock as they completed maintenance. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy (60 FR 34380, June 30, 1995). The petcock was closed and restoration of the EDG was completed. The licensee wrote a PIF to evaluate and track corrective actions.

In a similar vein, operations was not informed of the removal for test purposes of an emergency service water motor operated valve (MOV) limit switch cover until more than an hour after the removal. During earlier discussions of the work the operators had concluded that removal of the cover might make the valve inoperable and therefore the operators' intent was to declare the valve inoperable upon notification that the cover removal was imminent. This was an excellent conservative approach to test activities by operations that was overcome by inadequate communications. Once operations was informed, the situation was promptly identified using the corrective action system and engineering promptly determined that the valve was operable with the cover removed.

The operators also identified a case where surveillance testing and MOV testing on the containment relief system were scheduled such that there was a potential to violate containment integrity for a relief penetration. The operators stopped the work until the schedule could be corrected.

Because they were identified promptly, these problems had no safety significance other than as indicators of continuing problems with communications, work scheduling, and control of valve positions.

3.0 ENGINEERING

NRC Inspection Procedures (IP) 37550, 37551, 40501, and 92903 were used to perform onsite inspections of the engineering function. Three examples of a corrective action violation were identified and consolidated in Section 5.1. No deviations were identified.

3.1 Engineering and Technical Support Self-Assessment

As discussed in NRC Inspection Report No. 440/95008, the licensee performed a self-assessment of engineering and technical support (E&TS) under their Quality Assurance Audit No. PA 95-25. The licensee's October 30, 1995, Audit Report concluded that engineering performance was adequate in the conduct of routine and reactive activities and in providing support to other Perry departments. The audit also concluded that recent initiatives addressing previously identified weaknesses had produced positive results; however, several programmatic weaknesses required further actions.

A multi-disciplined NRC team evaluated the licensee's E&TS self-assessment effort to confirm the completeness of their review, to determine whether the self-assessment sample provided a reasonable basis to support their conclusions, and to review the proposed corrective actions. In addition to the items included in the self-assessment, an independent sample of other design change packages (DCPs) and corrective action documents were reviewed by the NRC team.

Based on these reviews, the NRC team concurred with the conclusions reached in the licensee's self-assessment. Most importantly, the team noted a significant improvement in the quality of the DCPs and safety evaluations compared to those reviewed in the previous NRC E&TS inspection. The extensive changes made to the design change program since the last refueling outage were considered to be effectively implemented with only limited problems. In addition, the NRC noted improvements in the documented bases for temporary modifications, in the lowered threshold for the corrective action process, and in engineering backlog reductions. However, the continuing weaknesses in design calculation verification, identified by both the self-assessment and NRC teams, demonstrated the need for continued improvement in this aspect of engineering fundamentals.

The E&TS self-assessment identified several programmatic weaknesses including no specified controls for Engineering Design Guide issuance, the lack of required design verification within the temporary modification process, and the return-to-service of partially implemented DCPs without proper evaluation or package closure. The NRC team considered these to be good findings, concurred with the evaluations that they did not cause significant safety concerns, and agreed with the proposed corrective actions. Also, the NRC team viewed the licensee's recently initiated Engineering Assessment Review Team, which will integrate the corrective actions from several previous self-assessments, as a very positive action.

Of the areas that the self-assessment noted as needing improvement, the failure to meet the expectations given in the recently issued system engineering handbook was notable. This was one of the major actions taken under the Perry Course of Action to "improve system engineering involvement in the plant work process." Although overall improvements had been noted in system engineering's performance, based on the audit results, additional efforts appeared warranted to either reinforce the existing guidelines or modify the expectations.

During the independent review of items within the scope of the licensee's self-assessment, the NRC team identified additional concerns or did not concur with the characterization of some issues.

Specifically:

- temporary modification 1-95-0016 was not correctly posted against drawing B-208-222-283;
- installation tolerances were not specified for the valves' angular orientation in DCP 94-0027;
- the initial lack of a system performance post-modification test for DCP 94-0027 was only considered an example of insufficient technical documentation instead of a DCP process failure.

While these shortcomings were not positive reflections on the self-assessment effort, the NRC team did not consider them significant enough to indicate an overall lack of thoroughness on the part of the licensee's team.

During reviews of items outside the scope of the licensee's self-assessment, the NRC team identified several issues that were indicative of additional problems. These are discussed separately below.

3.2 Inadequate Evaluation of Reactor Vessel Water Level Decrease

As discussed in NRC Inspection Report 440/95008, the conclusions drawn in the licensee's report regarding unexpected reactor vessel water level changes were not supported by their evaluation. Although the evaluation documented a vessel level decrease between 1 and 2 inches (which represents 200 to 400 gallons of water), the report concluded that level changes did not occur when aligning the residual heat removal (RHR) system in the shutdown cooling (SDC) mode. This contradicted operator's statements given in July 1994, that a 5 inch level drop was routinely observed when aligning RHR in SDC mode. The report addressed neither the causes of nor the hydraulic transient response to the apparent ongoing 25 to 50 cubic feet void in the RHR system and did not evaluate the system for the potential effects from the more significant July 1994 event. See Section 5.1 of this report for disposition of this issue.

As further contradiction to the report's conclusions, on November 13, 1995, an estimated 5 inch reactor water level decrease occurred when the RHR outboard SDC isolation valve was opened, and a banging or popping noise was reported by proximate personnel. The licensee initiated PIF 95-2301 to document and investigate the occurrence. The cause of the event was characterized as a design deficiency and was attributed to the formation of steam voids in the SDC piping due to thermal conditions. A design evaluation of the thermal and mechanical loads was performed and concluded that the RHR piping and supports remained adequate for restart from the forced outage. The licensee instituted procedural changes to minimize the hydraulic transient and proposed SDC suction line monitoring to validate their resolution of the issue. The NRC inspectors acknowledged these interim measures and will evaluate the licensee's long term resolution of this issue.

3.3 Calculational Discrepancies Not Documented In Corrective Action Program

Calculation No. E21-4, "1E21C002 Water Leg Pump Performance Related to Keepfill," dated May 9, 1995, noted that the original calculation had several deficiencies which resulted in the available system head falling short by 13.5 feet of water. The original calculation used the wrong temperature, did not consider the keepfill function for the highest elevation, and did not properly consider the atmospheric pressure for the available head pressure. The new calculation revised some of the conservatism in the original calculation and demonstrated that even with additional head loss due to the modification, the design was acceptable.

From a technical perspective, the NRC inspector considered the identification of deficiencies in the original calculation as an excellent example of a questioning attitude on the part of the designer. However, this deficiency was not documented in the corrective action program until November 16, 1995, when PIF 95-2355 was issued. See Section 5.1 of this report for disposition of this issue.

3.4 Inverter Failure Mode Not Recognized And Evaluated

As discussed in NRC Inspection Report No 440/95008, two recent reactor scrams resulted from an inverter failure in the Division 2, 24 VDC power supply for the RCIC trip units. While investigations into earlier inverter failures concentrated on the failure causes, the licensee's recent investigation focussed on the failure consequences and why a single component failure caused a RCIC initiation/main turbine trip/reactor scram. By design, RCIC initiation causes a main turbine trip due to moisture carry-over concerns; however, the loss of an individual inverter should not, by design, have caused a RCIC initiation. The licensee's investigation found that on an inverter loss, the energy stored in the power supply capacitors was sufficient to momentarily energize the trip units, seal-in the signal, and initiate RCIC. This failure mode had apparently not been considered in the original design and the trip logic design did not compensate for it.

After identifying this issue, the licensee prepared a modification to prevent a RCIC initiation due to trip signals from only one Division. The NRC inspectors were concerned because the root cause evaluations and corrective actions from previous inverter failures were not broadly based and did not identify this design weakness earlier.

3.5 Engineering Support of the Drywell Fan Forced Outage

As a result of the failed drywell lower area fans, Design Engineering analyzed the effects of increased drywell temperatures on the structures and instrumentation in the affected areas. The maximum average temperature was 224 degrees F and the limiting component impacted was determined to be the bioshield wall interface, with a maximum allowable temperature of 296 degrees F. The highest single recorded temperature was 232.5 F. The analysis concluded that continued plant operation was acceptable. However, plant management decided to shut down the plant and replace the fans. Good continuous engineering support was provided during the outage to preserve failure cause information and resolve problems identified during the fan replacements (see Section 2.1).

3.6 Engineering Support of Fuel Leak Location Was Good

On October 22, 1995, chemistry personnel determined that sample analysis results for xenon-133 indicated the possibility of a nuclear fuel leak. This information was promptly documented and turned over to reactor engineering for evaluation. Chemistry personnel increased their sampling frequency for xenon-133 and then conducted the extensive sampling program recommended by reactor engineering and provided the data necessary to allow the leak to be located and suppressed. These actions were completed before there was any measurable increase in dose effective iodine.

4.0 PLANT SUPPORT

NRC Inspection Procedures 71750, 81700, 84750, and 92904 were used to perform an inspection of Plant Support Activities. No violations or deviations were identified.

4.1 Radiation Protection Performance

Earlier in the year the licensee had conservatively lowered its self-imposed collective radiation dose limit for the year from 95-person rem to 51-person rem. During this inspection period higher dose limits were necessary due in part to emergent work items. However, the new limits were still exceeded in four of the six weeks. Work was stopped on two jobs when dose exceeded 125 percent of the estimated dose for the job. Stopping work was a positive action to minimize dose. The process for estimating dose for work activities will be reviewed by Region III health physics inspectors during the next inspection period.

The licensee identified recurring minor problems with electronic dosimeters and a high radiation area that was not properly posted. These items will be reviewed by Region III health physics inspectors during the next inspection period.

4.2 Fire Protection Response Was Good

On October 24, 1995, a nonlicensed operator observed smoke coming from emergency lighting panel 1R71-P022. He also observed flames inside the panel. The licensee had just restored DC electrical power to the panel during post-maintenance testing after completion of a new repetitive task. The licensee promptly called out the fire brigade and deenergized the panel. The smoke and flame stopped when the panel was deenergized and no fire suppression was required. The fire had involved the DC solenoid-operated power transfer switch inside the panel. The switch was designed to auto-transfer the lighting circuit to a DC source when the AC source was lost and auto-transfer the circuit back to the AC source when AC again became available. The solenoid was designed to be energized only momentarily during transfers and drew less current than the lighting circuit. Mechanical binding caused the solenoid to remain in the energized position and overheat. The protective circuit breaker for the circuit did not open because the lights were not energized and the solenoid alone did not draw abnormal current for the circuit.

The licensee promptly determined that the new repetitive task could be improved and increased its scope to include inspection and manual operation of the transfer switch. The original repetitive task required that the panel be inspected with only the outer door open. The transfer switch, behind an interior metal panel, was not visible. Both AC and DC power sources were isolated from the panel when the task was performed. The post maintenance test was similar to emergency operation of the transfer switch because DC power was restored before AC power was restored. Although the licensee developed the original repetitive task before there were any equipment problems, the fire indicated that if the AC to DC transfers had been required due a loss of AC power earlier, there may have been multiple failures of transfer switches which would have left the operators to face partial loss of lighting and multiple indications of fires in the plant at the same time they might have had challenges coping with other results of loss of AC power. If the repetitive task had been developed sooner and had it been more complete the possibility of solenoid failure would have been reduced.

On November 14, 1995, an instrument and controls (I&C) technician observed smoke coming from a small control power transformer inside Fire Protection Panel 1M36-N031B in the offgas building. The I&C technician was performing a repetitive task in the panel a few inches from the transformer at the time. The technician promptly notified the control room of the smoke and the control room directed the fire brigade to respond. An inspector responded to the control room and observed operator response. No flame was observed and the smoking stopped when the transformer was promptly deenergized. No fire suppression was required. A Perry Township Fire Department truck arrived at the plant, but did not enter the protected area because no assistance was required. The Perry Fire Chief entered the protected area and briefly discussed the event with the plant fire brigade leader. The licensee's response to the report of the smoking transformer was prompt and appropriate. At the conclusion of the inspection report period the licensee had not completed its evaluation for the transformer failure.

4.3 Housekeeping Declined

The inspectors noted that the amount of loose material (i.e., tools, face shields, extension cords, loose trash, etc.) in the plant had increased during the inspection period. Also, several minor leaks were found by the inspectors (i.e., pump casing warmup line leaking, roof equipment hatches leaking, waterleg pump oil leaking) that had not been identified with appropriate actions taken. Some of these items were the result of increased work activity by contractors and the recent forced outage. However, a number of the items had existed for an extended time. Licensee personnel identified similar conditions independent of the inspectors. Licensee management directed personnel to increase clean up activities and directed managers to improve their inspections of the plant.

4.4 Chemistry Support of Fuel Leak Location Was Good

On October 22, 1995, chemistry personnel determined that sample analysis results for xenon-133 indicated the possibility of a nuclear fuel leak. The communications, coordination, and support to operations, engineering, and radiation protection were good. This issue is discussed in greater detail in Section 3.6.

5.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (SAQV)

NRC Inspection Procedures 40500, 92720, 92901, 91902, 91903, and 91904 were used to perform an inspection of Safety Assessment and Quality Verification activities. One violation with three examples of inadequate or untimely corrective actions was identified. No deviations were identified.

5.1 Corrective Actions Were Sometimes Untimely and Ineffective

As discussed in Section 3.2, as of December 1, 1995, the licensee had not completed an evaluation that was adequate to determine whether a condition adverse to quality that had been identified on July 12, 1994, was significant. Therefore corrective action for the condition was not prompt. The condition identified was related to a 10-inch drop in reactor pressure vessel water level observed on July 11, 1994, while the plant was shut down. This is an example of a violation (50-440/95009-01a) of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," which required, in part, that measures be established to assure that conditions adverse to quality, such as failures and deficiencies, were promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition was determined and corrective action taken to preclude repetition.

As discussed in Section 3.3, the licensee did not promptly use the measures established to formally identify a condition adverse to quality (errors in safety-related calculations) in that errors observed on May 9, 1995, were not formally identified in the corrective action system until November 16, 1995. This is an example of a violation (50-440/95009-01b) of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," which required, in part, that measures be established to assure that conditions adverse to quality, such as failures and deficiencies, were promptly identified.

As discussed in Section 2.2 the licensee did not assure that corrective actions would preclude repetition of improper assembly of a compression fitting for safety-related tubing, a significant condition adverse to quality. Following an improperly assembled fitting discovered by the NRC on April 1, 1994, another similar improperly assembled fitting was identified on November 2, 1995. The second fitting was assembled sometime after October 31, 1995. In both cases the fitting compression nut was tightened so that it was in contact with the fitting. This is an example of a violation (50-440/95009-01c) of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," which required that measures be established to assure that conditions adverse to quality, such as failures and deficiencies, were promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition was determined and corrective action taken to preclude repetition. There was evidence that some personnel were sensitive to the proper installation of compression fittings since the M14 example was promptly identified and other personnel promptly identified improperly vendor-assembled fittings on a secondary system sample skid.

5.2 Identifying and Responding to Anomalies in the Plant

Problems in this area had been identified in recent inspection reports. Three significant examples are discussed in Section 5.1 above. There were other, less significant, examples as well. The licensee identified a case where a PIF was not forwarded after being brought to the control room. The PIF identified a problem with dew point determination for a temporary instrument air system and operations resolved the issue with engineering. However, the PIF should have still continued through the corrective action process. In another case the inspectors reported finding an individual's security badge and thermoluminescent dosimetry in the drywell and determined that no PIF was written. In this case there was confusion among licensee personnel on the facts of the identified situation and whether a PIF had been written.

5.3 Quality Assurance (QA) Audits and Surveillances

The inspectors reviewed several QA audits and surveillances and concluded that they were thorough and technically sound. Good findings were documented in a variety of areas. One example was an audit of environmental qualifications. Several problem areas were identified and QA personnel followed up with additional observations of similar plant equipment to ascertain that there were no other examples of those problems. This included observations in the drywell when that area became accessible during a forced outage. Another example was the audit of cold weather preparations which identified programmatic problems as well as implementation problems. Although the audit was excellent, the problems identified should have been corrected as a result of related problems identified the previous year.

6.0 LICENSEE ACTION ON PREVIOUSLY OPENED ITEMS (Violations, Unresolved Items, Inspection Followup Items)

NRC Inspection Procedures 92720, 92901, 92902, and 92903 were used to perform follow-up inspection of the items below.

(Closed) Inspection Follow-Up Item (50-440/93019-02): "Prioritization of Responsible System Engineer (RSE) Workload for the Short and Long Term Support of Plant Systems." Perry Course of Action Item No. 3.5.2.5 included the issuance of a system engineering work practice instruction outlining management's expectations for RSE's day-to-day activities. The System Engineering Handbook was issued in June 1995, which listed time allocation goals and system work prioritization. Based on a review of this document, this item is closed. See Paragraph 3.1 of this report for additional discussion of this topic.

(Closed) Violation (50-440/93019-04): "Failure to Take Appropriate Corrective Actions for Room Coolers and Waterhammers in the Radwaste System. The licensee's actions to correct the specific issues discussed in this violation were considered to be adequate. With respect to the actions taken to avoid further violations, the licensee stated that the need for overall improvement in the corrective action program was recognized within the Perry Course of Action and that actions and activities were identified to address this issue. Although improvements have been noted in the overall effectiveness of the corrective action program, continued weaknesses have been identified in the program implementation. See Paragraph 5.2 of this report for additional discussion. This item is closed.

(Closed) Violation (50-440/94011-03): "Safety Evaluations Fail to Provide Bases for Determination that a Change Did Not Involve an Unreviewed Safety Question." Based on the reviews performed during the E&TS inspection documented in Paragraph 3.1 of this report, the programmatic corrective actions taken by the licensee appeared to be effective. This item is closed.

(Closed) Violation (50-440/94011-04): "Design Controls Fail to Verify the Adequacy of the Design." Based on the reviews performed during the E&TS inspection documented in Paragraph 3.1 of this report, the programmatic corrective actions taken by the licensee appeared to be effective. This item is closed.

(Closed) Inspector Followup Item (50-440/93019-01(DRS)): Implementation of a deficiency tagging program. The inspectors observed that the licensee had implemented a deficiency tagging program that used green tags or labels to identify plant deficiencies at or near the deficiency. The tagging form also included a work request form. The program had been effective in improving the identification and visibility of deficiencies. This item is closed.

(Closed) Inspector Followup Item (50-440/95005-01(DRS)): Evaluate corrective action for inadequate condition report investigation. The inadequate investigation was for an improperly installed tubing compression fitting on an emergency diesel generator (EDG). This inspection report includes a violation for inadequate and untimely corrective actions. One example of that violation was recurrence of improper installation of a compression fitting. The inspectors will review the corrective actions for the EDG fitting during their review of the licensee's response to the violation. This item is closed.

7.0 Persons Contacted and Management Meetings (Exit)

The inspectors contacted various licensee operations, maintenance, engineering, and plant support personnel throughout the inspection period. Senior personnel are listed below.

At the conclusion of the inspection on December 1, 1995, the inspectors met with licensee representatives (denoted by *) and summarized the scope and findings of the inspection activities. The licensee did not identify any of the documents or processes reviewed by the inspectors as proprietary.

D. C. Shelton, Senior Vice President
R. D. Brandt, General Manager Operations
N. L. Bonner, Engineering Director
R. W. Schrauder, Nuclear Services Director
K. R. Pech, Nuclear Assurance Director
*M. B. Bezilla, Operations Manager