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OFFICE OF NUCLEAR REACTOR REGULATION

Division of Reactor Inspection and Safeguards

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Licensee: The Cleveland Electric Illuminating Company
P. O. Box 5000
Cleveland, Ohio 44101

Inspection At: Perry Nuclear Power Plant
Perry, Ohio

Inspection Conducted: March 14-25, 1988

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1.0 INSPECTION SCOPE

The primary focus of the inspection was the safe operation of the Perry Nuclear Power Plant. The inspection effort was concentrated on control room operations and activities that interfaced with operations and supported the safe operation of the plant. As a part of the operations performance evaluation, the team observed 162 hours of shift coverage and conducted random backshift and weekend inspections. In addition to observations of operations, inspections in the areas of maintenance, surveillance, management oversight, safety review, and quality programs were performed.

2.0 DETAILED INSPECTION FINDINGS

2.1 Operations

During the inspection period, the team of nine inspectors observed operating activities in the control room and in the plant to obtain a representative overview of the licensee's conduct of operations. Of the 162 inspector-hours spent in direct observation of activites, 95 hours were spent on backshift and weekend coverage. Sixteen shift turnovers were observed in the control room, involving randomly selected licensed operators serving in the capacity of Shift Supervisor (SS), Unit Supervisor (US), or Supervising Operator (SO). Several turnovers within each shift were observed among licensed operators.

2.1.1 Shift Routine

The team members observed that, during all three shifts control room decorum reflected professional attitudes that emphasized control over the facility and shift activities. The noise level in the general area was sufficiently low that it did not interfere with communications among operators, and traffic control in the horseshoe-shaped control area was adequate to properly restrict access. In every instance, inspectors who entered the horseshoe area, after first obtaining permission from a licensed operator, were challanged by other on-shift personnel. Responses to annunciations were generally thorough, although several team members observed separate examples of operators who cleared alarming annunciators without appearing to look at the annuciator panel to determine the source of the alarm condition.

Control room operators were found to be generally aware of plant status, component condition, and system configuration. Turnovers during shift change were usually thorough, although inspectors did note differences between operating crews in the depth and detail of information passed along to the relieving crew. Inspectors also noted that the oral and written turnovers often lacked a historical update of events and activities. One example was the ongoing diagnosis of problems with steam accumulation in the shutdown cooling portion of residual heat removal (RHR) system piping. Although the operating staff's involvement included temperature monitoring programs, periodic filling and venting procedures, and communication with the Systems Engineering Group, little mention was made of the evolution of the problem among operators. Oncoming shift personnel regularly reviewed logs and other supporting documents, including the active and potential limiting condition for operation (LCO) logs and the work order list, and were observed to walk down the control room panels alone and with the offgoing operator. There appeared to be sufficient time alloted for shift turnovers, and there were no observations of a turnover conducted quickly to permit rapid relief of the offgoing crew.

While shift turnovers were generally thorough and lengthy, within shift turnovers conducted between operators on the same crew were regularly observed to be brief and informal and to rely heavily on the assumption that the relieving operator was fully versed in plant status. In one instance, a relief between SOs lasted an estimated 10 seconds and included 2 items related to tests or evolutions in progress. In another instance, a US being relieved by the SS had been involved in an interview with a team member for approximately 25 minutes prior to his brief turnover. The inspector observed

that while the SS was present in the control room for that period, no communication occurred between the two operators.

The team evaluated the accuracy and effectiveness of control room log-keeping by reviewing the unit log maintained by the SO, the active and potential LCO logs, and special logs for data collection on RHR shutdown cooling system piping. Midnight unit log entries, which provide a daily plant status summary, were generally thorough and detailed. While the unit log was formally maintained, team members often found it to be lacking in depth and detail. For example, team members who had followed two major events during the inspection period, RHR problems and one inoperable main steam isolation valve (MSIV), were able to reconstruct the basic elements of the two events in sequence, but the detail contained in the unit log entries was insufficient to permit analysis of the event or aid in its diagnosis. Team members identified discrepancies in the thoroughness of unit log entries by comparing the inspector's knowledge of an event that had been observed with the unit log entry used to document that occurrence. For example, for the March 28 power decrease resulting from isolation of one MSIV, no explanation of the event was documented. Likewise, the procedural deviation described in section 2.1.2 of this report that occurred during venting and filling operations on RHR piping on March 22 was not mentioned, nor was the verification of the position of the valve that was incorrectly operated. Despite the personnel errors and procedural deviations the unit log recorded only that the venting and filling evolution had been completed satisfactorily. Both these examples describe incidents in which the requirements of procedure OAP-1702, "OPS Section Rounds, Logs, and Records," were not met. Additionally, although the procedure requires the unit log to be a "hardbound, sequentially numbered document," inspectors observed that the unit log was being maintained on individual sheets inserted in a three-ring loose-leaf binder and that on two occasions individual sheets had torn at the three holes and become separated from the binder. Licensee personnel indicated the intention to return to the use of a hardbound document. The above examples of failure to properly maintain the unit logs is an observation (440/88200-01).

Team members observed that the LCO logs, were disorganized and contained entries that appeared to offer only a sketchy explanation of a condition that led to an LCO. Nonetheless the logs were useful for those who used them regularly. The operators interviewed were consistently able to identify and describe equipment deficiencies, plant conditions, and applicable time constraints related to the LCO. Further, the effectiveness of the LCO tracking system was an apparent contributor to the reduced number of LCO violations since the facility's startup test phase.

Data collection logs associated with RHR piping problems were thoroughly kept in accordance with temporary instructions.

Status boards mounted in the horseshoe area were observed to be effectively utilized by shift personnel. The emergency core cooling system (ECCS) status board was maintained current, and accurately reflected the degraded condition of RHR system piping. While the new electrical lineup status board was maintained, the unofficial "note pad" style status board used by the US was not generally maintained current. Interviews with shift personnel indicated that the board was a wall-mounted equivalent of a note pad and was not relied upon for accurate plant status. Operators appeared to be familiar with the use of the computers available in the control room and the status information

available, particularly the computerized work order list used as the only reliably maintained list of work in progress. In addition to generally being current with regard to plant status, operators were usually found to be knowledgable regarding equipment operating characteristics and peculiarities of control room instrumentation and how those characteristics could affect plant operation. For example, operators were aware of the difference between the indicated and actual level on RHR heat exchanger A.

Licensee personnel were, in general, effective in their control of not-in-service (NIS) and information tags. Implementation of procedures for both types of tagging was evaluated by checking approximately 200 tags against the requirements of Plant Administrative Procedure (PAP) 1401, "Safety Tagging," Revision 3, and through inspection of the tag logs, tag placement, and operator interviews. The team confirmed that the required supervisory reviews and approvals and periodic audits were made and that the tags were properly logged. The licensee has emphasized minimizing the number of active NIS tags by timely repair of out-of-service instruments and annunciators, and progress was routinely reported in the monthly management trend reports. During the inspection period, active NIS tags numbered six per month for 1987 and three per month for 1988. A review of the declining long-term trend indicated that continued management emphasis on timely equipment repair was effective.

Inspectors reviewed the control of jumpers and lifted leads by evaluating the effectiveness of alterations made during the inspection period on the high pressure core spray (HPCS) test return valve 1E22F011. Tag orders and the associated 10 CFR 50.59 applicablity checks were found to be in compliance with the requirements of PAP 1402, "Control of Lifted Leads, Jumpers, Electrical Devices, and Mechanical Foreign Items," Revision 5. A review of the modified system configuration showed that the intended purpose of the alteration, that of maintaining certain HPCS related annunciators operable, had been met without undesirable side effects. Although isolated examples of minor record keeping discrepancies were identified, the team concluded that licensee personnel were generally effective in controlling lifted leads and jumpers.

The team observed deficiencies in the communications equipment available in the Unit 2 control room area for use by the SO to supervise the nonlicensed plant operators. Those deficiencies had been previously identified by the licensee and installation of communications equipment comparable to that in Unit 1 was planned for the future. The team concluded that this additional equipment should enable the SO to communicate directly with plant operators without funneling communications through the SO at the controls of Unit 1 and permit the control of certain equipment common to both units from the Unit 2 control room.

Team members touring the plant noted that plant cleanliness was generally adequate. The material condition of unpainted carbon steel piping located inside the containment was, however, of concern to team members, who noted scaling and flaking rust on welded joints in RHR low pressure coolant injection (LPCI) piping and other piping in nonsafety-related systems. Exterior surfaces of the piping in the vicinity of welded joints had, in some locations, deteriorated to the point that pits were visible.

With the possible exception of the interface between operations personnel and the Systems Engineering Group, the team determined that the operations interface with other licensee organizations was generally efficient and productive.

Maintenance personnel, for example, regularly adjusted the aggressive cyclical maintenance schedule to address problems which had the potential for adversely impacting plant operation or causing an LCO. Likewise, the Reactor Engineering Group worked with the operators to prepare a visually displayed power/flow map that was used regularly. Interviews with operations personnel revealed frustrations with the operations/systems engineering interface that appeared to be rooted in the operator's desires to be active contributors to the resolution of problems affecting plant operation. Interviews with licensee management determined that this interface problem was well-known to management and was under review.

The team concluded that licensed operators on watch in the control room had professional attitudes, displayed pride in the quality of their performance, and had appropriate concern for safe facility operation. Through interviews and observation of interaction with other licensee personnel the team concluded that operators clearly understood that the license carried with it both the responsibility and authority to supervise and direct the activities of others in the interest of safe reactor operation. Team members frequently observed an interest among operators in the events that occurred during the inspection period and a desire to contribute toward the prompt resolution of equipment problems that impacted operation. Such interest was indicative of good morale among the operating staff. Licensed operators appeared to have a sound understanding of integrated plant operations, as evidenced by their understanding of the relationship between the RHR, reactor water cleanup, and condensate transfer systems during the diagnosis of RHR system malfunctions.

Likewise, observations and interviews with nonlicensed plant operators indicated enhanced understanding of facility layout, design, and operation when compared with their general knowledge level during the plant's startup test phase. Plant operators seemed to be familiar with the operating characteristics of individual plant components and with the general administrative and record-keeping requirements associated with nuclear plant operation. Plant operators also appeared to have a reasonable understanding of integrated plant operations, as illustrated by one plant operator's understanding of why the HPCS room floor drain could not be left partially open to permit continuous draining of the sump without impacting the operation of other systems located in separate rooms. Plant operators seemed to display an appropriate sense of responsibility and concern for the material condition of the facility and the impact of the material conditions on safe plant operation, as evidenced by the manner in which plant operators were observed checking bearing temperatures, draining air dryers, and changing annunciator panel light bulbs. Plant operators appeared to be current on the status of maintenance activities ongoing in the plant and responsive to off-normal conditions. For example, one plant operator who heard what may have been a water hammer in RHR piping notified the control room and investigated in the area for pipe hanger damage.

2.1.2 Procedural Control

As team members observed activities in the control room and in the plant, operator actions were compared with the requirements of the appropriate approved procedures applicable to the activity. The procedures were found to be maintained in a current condition, and observations in the control room indicated that the applicable procedure was utilized as a reference or working document for even the most routine evolutions. Procedural content was complete

and all numerical values and setpoints were present, indicating that the transition from construction and startup test phases to the operational phase was reflected in the body of the procedures. Interviews with operators indicated that the numerical values, setpoints, and equipment operation guidance contained in the procedures reflected the actual operational characteristics of the plant and not simply the design characteristics, thus adding to their usefulness as working documents on which operators could rely. Each procedure appeared in general to be sufficient in that it contained all the necessary acceptance criteria, supporting data and formulas, and administrative controls, such as sign-off verifications.

The volume of temporary changes to procedures appeared to be managable for operators using the document in the field. The potential for confusion caused by temporary changes was greatly diminished by incorporating the changes into the body of the procedure by replacement of an entire revised page rather than attaching a temporary change to the front of the procedure. Using margin bars to note the changes helped operators stay aware of temporary changes. The team did not identify any appreciable time lags in the management approval or administrative processing of permanent procedural changes.

The team noted that the actual total number of procedures was approaching 4000 and still growing as the plant's first refueling outage approached. This substantial volume of procedural guidance could become difficult to administratively control and utilize effectively; but nonetheless the team was unable, with the assistance of operators, to identify a single example of duplication, contradiction, or confusion among procedures. Operators consistently demonstrated their ability to identify and effectively utilize the appropriate procedure. This performance led the team to conclude that the seemingly excessively large volume of procedures had not detracted from safe or efficient plant operation.

Standing instructions were evaluated, and they appeared to effectively fill the time lag between management's decision to alter a particular operating practice and publication of the actual procedure change. For example, pending a procedural change to require operators to accept an RHR shutdown cooling isolation rather than attempt a bypass of the reactor protection system (RPS) during certain surveillance tests, a management directive was immediately distributed to operators via a standing instruction, that permitted the RPS bypass.

Compared with skills observed during the startup testing phase, operators had made significant progress in the use of the technical specifications as a working document, as evidenced by the decrease over the last year in the number of missed surveillance tests and LCO violations.

Team members saw evidence in two instances that, while procedures were routinely and effectively used in the control room, activities with the capacity to affect facility safety were being conducted in the plant without benefit of procedural control. In the first instance on, March 22, 1988, two plant operators attempted to vent and fill RHR system piping but incorrectly attached the vent hose to a valve in a separate portion of RHR piping located near the correct vent valve. Venting through the incorrect valve did not yield the expected discharge of steam and hot water. The plant operators did not, however, question the apparent inconsistency, even though this activity had been conducted before and the expected results had been obtained. The entire

evolution was conducted without written procedural guidance and without guidance from the SO in person or via radio, even though a surveillance procedure existed to perform the filling and venting operation. The evolution was successfully completed after the team members investigated and discovered the incorrect valve lineup. The above failure to exercise proper procedural controls is an observation (440/88200-02).

In addition to the absence of appropriate procedural controls, factors contributing to this incident included:

- invalid assumptions on the part of each plant operator that the other was fully versed in the evolution,
- operator unfamiliarity with the piping configuration,
- a willingness to readily accept unreasonable and unexpected results without further investigation,
- absence of supervisory control on the scene or via radio.

The filling and venting activity was completed successfully approximately 3 hours later using an appropriate procedure, but still without SO supervision. No mention of the incident or verification of the correctly restored valve lineup was inserted in the unit log. No condition report (CR) was generated until two days later when a team member raised the question.

In a second instance on March 23, 1988, the team member on the scene in the RHR room did not observe the use of procedural guidance during valve manipulations. The confusion among plant operators and the absence of SO involvement was again apparent to the inspector.

2.1.3 Operator and Station Qualifications

Based on observation and interviews with licensed operators staffing the control room, the team concluded that both the quantity and quality of operators appeared adequate to ensure safe facility operation. Operator knowledge of component design, construction and operation, system configuration, and integrated system operation was determined to be generally high. The team saw evidence that as the design characteristics of components and systems were revised to reflect operating experience, operators had an active interest and integrated that new knowledge into their operating strategies. The team expects the operator knowledge level to improve as the plant moves toward routine full-power operation. Likewise, the team concluded that the quantity and quality of nonlicensed plant operators was sufficient to support plant operation and emergency response.

The team expressed concern over the role of the SO as fire brigade leader. While fully supporting the licensee's decision to have a licensed operator making operational decisions during a fire emergency, the team considered that the designated fire brigade leader should not be the SO at the controls of the reactor so as to provide for prompt brigade leader response without the need for a within-shift SO turnover. During the inspection period, the licensee made a commitment to revise PAP-0301, "Conduct of Operations," to change the

manner in which the brigade leader is designated so that the designated SO would not be the SO at the controls of the facility. In addition, the licensee will revise the method by which the fire brigade attack team leader is designated to ensure that a trained and qualified individual is assigned. The licensee also agreed to provide all attack team leaders with training comparable to that provided to the fire brigade leader through modification of PAP-1917, "Fire Protection Training Programs." This action addressed the team's reasoning that the attack team leader directing fire fighters at the scene of the fire should be able to fully assess the situation and provide appropriate information to the brigade leader at the command post location physically removed from the fire scene.

The team regarded the depth of fire-fighting experience among personnel in the security and fire protection sections as a strong asset to support plant operations. The licensee's emphasis on fire protection training was considered to be a strength.

The team identified an apparent need for greater SO involvement in directing the activities of nonlicensed plant operators performing duties in the plant. The team concluded that, while plant operators performed routine duties thoroughly, they did not demonstrate the knowledge of conservative, integrated plant operation necessary to conduct evolutions without appropriate guidance and supervision. The incident involving venting from the incorrect RHR valve described in section 2.1.2 is an example. In that event, the involvement of the SO in ensuring that the operation was carried out safely and successfully was conspicuously absent. The SO did not provide the plant operator with the available procedure, review the procedure requirements with the plant operator, or rehearse the activity. Nor was the SO present on the scene or in radio contact. The SO was not visibly involved in verification of the restored valve lineup once the incorrect lineup was discovered. During the second performance of the venting and filling activity, approximately three hours later, the SO prepared procedural guidance for use by the plant operator but was still absent from the scene and not in radio contact. This failure of SOs to direct ongoing activities is an observation (440/88200-03).

There was an observed need for plant operators to improve attention to detail while in the plant, including enhanced attention to radiological control practices and the ALARA concept. For example, while touring in containment, the team observed that plant operators failed to notice significant leakage from a maintenance project in progress. While performing RHR venting and filling activities, plant operators ignored water that had leaked onto the floor. That water was later found to be slightly contaminated. In another instance an operator reached across a roped radiological barrier to use, as a writing desk, the top of a drum identified as containing contaminated clothing.

In addition to considering that the SO supervising plant operators should spend more time in the plant, the team identified a need for managers above the SS level to regularly tour the facility. Inspectors reviewed security computer records from the last quarter of 1987 that documented access through entry doors into the control room, the radiologically controlled area (RCA), and containment for eight managers above the SS level. With two notable exceptions, the management group visited the control room infrequently, rarely made RCA entries, and virtually never entered containment. Supporting data are not presented in this report because the licensee determined that these data were

safeguards information. The licensee informed the team, however, of a newly implemented program to require increased management touring in the plant.

The inspectors observing control room activities identified as a significant concern the administrative burden placed on the US as the SRO-licensed individual required to approve all work and surveillance activities in the plant. The paperwork demand on the US was observed to be so time consuming as to potentially impede his ability to supervise control room operations. The administrative burden distraction for the US was considered by the team to be extreme during the day shift, difficult during the evening hours, and manageable on the midnight shift. The inspectors noted and supported the licensee's decision to have one licensed supervisor authorize and control all work, but expressed concern that this duty seriously detracted from the ability of the US to perform other supervisory duties considered important to safe facility operation. Those individuals interviewed indicated that the US and SO rarely toured in the plant.

The demanding workload on the US was passed along in great part to the SO at the controls because nearly all technicians, maintenance personnel, and contractors who receive work authorization from the US must then interface with the SO in order to actually accomplish the authorized work. The distracting demands on the SO were exacerbated by the volume of surveillance tests, requests for keys and information, and required telephone notifications of work such as welding. Like the load on the US, the day shift SO had the greatest burden. Inspectors on several occasions observed that the SO suspended all contact with nonoperators and turned to the control panels to assess plant conditions.

The team concluded that the recently implemented corporate smoking policy has resulted in the occasional absence of licensed on-duty operators from the control room. Because the closest designated smoking area was well-removed from the control room, the team's concern focused on the absence of key watchstanders from the control room for a nonplant-related activity. The team concluded that any time essential licensed personnel were absent from the control room the crew's ability to respond to emergencies was diminished. In one observed instance, a US was absent from the control room for a smoking break for 19 minutes. The US provided only a brief turnover to the SS relieving him, and did not carry a radio. However, there were public address speakers in the designated smoking area. The team emphasized the importance of maintaining a full shift complement readily available and the need to minimize absences not related to operation of the facility.

2.1.4 Shift Overtime

The team reviewed the licensee's controls for approval of overtime for personnel performing safety-related functions and key maintenance activities. PAP-0110, "Shift Staffing and Overtime," Revision 2, established the guidelines and requirements for the approval of overtime for key personnel. PAP-0110, Section 6.5, "Overtime Guidelines," required that prior to making an overtime assignment, any supervisor shall review the individual's overtime hours for compliance with the overtime guidelines and shall initiate an overtime deviation request when needed.

A review of the Operations, Maintenance, and I&C Departments' overtime and attendance records for the three months preceding the inspection identified eight instances in which the overtime guideline limit had been exceeded but had not been approved and one instance in which blanket authorization to exceed the overtime guideline limit was approved.

In the first instance, the team found that three power plant operators (PPO) and two I&C technicians had exceeded 72 hours in 7-days (excluding shift turnover) without an overtime deviation request authorization. One PPO had exceeded 24 hours in a 48-hour period without an overtime deviation request authorization.

In the second instance, the team noted that a memorandum from the Maintenance General Supervisor to the Operations Department Manager, dated January 15, 1988, was used as a blanket overtime deviation request to exceed the 72 hours in 7-days guideline because of outage work. In this case, the individuals exceeding the overtime guideline limit were not identified, nor was there evidence that the potential impact on plant safety was considered for the individual's overtime work activities.

In both instances the requirements of PAP-0110 were not observed. Further, this practice was inconsistent with the published NRC policy statement, dated February 11, 1982, "Policy on Factors Causing Fatigue of Operating Personnel at Nuclear Reactors." The team recognized that the licensee's Quality Assurance (QA) Department had previously identified the blanket overtime deviation request as a problem. In response to the QA finding, the Maintenance Group Supervisor made a commitment to provide an itemized list in the overtime deviation request prior to individuals exceeding the overtime guideline limit.

The team was concerned that excessive or unmonitored overtime could significantly reduce the effectiveness of operating personnel. During this inspection, the licensee acknowledged the team's concern and indicated that improvements were needed in this area. These examples of excessive or unmonitored overtime constitute an observation (440/88200-04).

2.2 Maintenance

The team reviewed the measuring and test equipment (M&TE) program, selected maintenance procedures, selected completed work requests, and examined the work planning and scheduling processes. Overall, the team found these areas to be adequately administered and controlled. The following strengths and weaknesses were noted in the maintenance functional area.

2.2.1 Work Planning and Scheduling

The scheduling and planning of preventive and corrective maintenance, surveillance testing, and design changes (modifications) were found to be an integrated activity. The licensee utilized a coordinated approach by removing a train or portion of a system from service on a scheduled quarterly basis for maintenance, surveillance testing, and modification work. Consequently, the disabling of safety systems was minimized by accomplishing all planned maintenance in a relatively brief period of time. At the time of this inspection, the licensee was in the first cycle of the quarterly schedule. Some minor problems were noted with the implementation of the quarterly maintenance schedule but were

considered to be typical program startup problems. For example, approximately 21 percent of the planned work from week 11 of the 13-week schedule was carried into over week 12. If this problem persisted, the potential cascade effect of excessive carryover from week to week would negate the usefulness of the quarterly maintenance approach. The team noted, however, that there was virtually no carryover from week 12 to week 13.

Based on a review of plant procedures and personnel interviews, the team considered the practice of integrated planning and scheduling of preventive maintenance, corrective maintenance, surveillance testing and design changes to be a strength.

2.2.2 Measuring and Test Equipment (M&TE) Program

The team reviewed the licensee's program for the control and administration of M&TE. Overall, the team was favorably impressed with the qualifications and knowledge level of the M&TE staff and the laboratory. One significant weakness in the licensee's M&TE program was evident. Administrative procedure PAP-1201, "Control of Measuring and Test Equipment," Revision 3, provided for the control of M&TE used in obtaining and establishing a high degree of confidence in the accuracy of safety-related measurements, as required by ANSI N18.7 and 10 CFR 50, Appendix B. Section 6.6 of PAP-1201, "Nonconformance of Perry Plant M&TE," Revision 3, required that whenever M&TE had been issued and later found to be out of calibration, the past reliability of the M&TE must be determined. PAP-1201 also required that an out-of-calibration report (PNPP Form 5861/A) be sent to each responsible user or issue point if the M&TE in question had been used on plant instruments. The lead supervisor or engineer for the responsible user group was then required to perform an evaluation to determine whether any plant equipment in service was potentially affected. If the operability of any plant system was in question, the lead supervisor or engineer was required to immediately notify the shift supervisor. The lead supervisor or engineer was then required to ensure that a work order was issued, or that a retest was performed to correct the potential problem.

At the time of this inspection, 123 out-of-calibration reports had been issued in 1988. Thirty-seven of the 123 reports were issued for M&TE that had not been returned to the M&TE laboratory for recalibration. In these cases, the M&TE was in calibration when it was issued; however, it had not been returned to the laboratory before its calibration due date expired.

The out-of-calibration report form provided seven evaluation codes to document the disposition of the work affected by the M&TE in question, as follows:

No Action Required Because:

A1 Affected range(s) was(were) not used.

A2 The error did not cause any test result/calibration to exceed equipment allowable tolerances.

A3 Instrument would not function, failure time and cause were known, and past reliability of the instrument was evaluated as being acceptable providing reasonable assurance that the instrument was in calibration prior to failure.

A4 Other: Attach specific remarks on the attached list or on a separate sheet of paper.

Based on the Evaluation:

B1 The equipment listed on the attached list as marked required to be rechecked/recalibrated.

B2 The equipment listed on the attached list was rechecked/recalibrated and no further action is required.

B3 Other: Attach specific remarks on the attached list or on a separate sheet of paper.

The team reviewed approximately 63 completed out-of-calibration reports to determine the acceptability and thoroughness of the evaluations. The team found that 10 of 15 reports for equipment that had not been returned to the M&TE laboratory had been disposed of inappropriately. Evaluation codes A1 - A3 were used routinely but incorrectly for the following reasons:

1. If an instrument was lost or not turned in, the "as found" calibration data were not available to identify the affected range (A1),

2. If an instrument was lost or not turned in, the "as found" calibration data were not available to identify the magnitude of the M&TE instrument error (A2),

3. If an instrument was lost or not turned in, there was no record of a review of past calibration data to support the contention that an instrument had failed in the field, that the failure time was known, or that the instrument had failed to function (A3).

The team was concerned about the failure to properly dispose of work affected by M&TE that was out of calibration. In some instances, the affected M&TE was used to perform surveillance tests, safety-related maintenance, and post-maintenance testing.

The team was also concerned with the licensee staff's apparent willingness to use equipment that was known to be out of calibration to obtain data. For example, out-of-calibration report 88-0078, dated February 24, 1988, was issued for equipment that had not been returned for calibration. The M&TE in question, a digital thermometer, was issued on November 5, 1987, and its calibration expired on November 20, 1987. However, this instrument had a quarterly calibration frequency. On March 8, 1988, out-of-calibration report 88-0078 was disposed with the following statement: "Equipment still in use in field. Engineering using to obtain data." The approval signature (responsible lead engineer or supervisor) for the disposition was made by the I&C Department supervisor. In response to the team's concerns, the M&TE in question was returned to the M&TE laboratory and recalibrated satisfactorily.

During the inspection, the process of evaluating work affected by out-of-calibration M&TE was discussed with the licensee. Cognizant licensee

staff personnel acknowledged the team's concern and indicated that improvements in the review and approval of out-of-calibration reports would be implemented.

2.3 Surveillance Testing

The team inspected the surveillance testing program, including program controls, implementation, scheduling, procedures, and post-surveillance data review. Several surveillance tests were observed, personnel associated with the program were interviewed, and plant records were reviewed to verify proper implementation of the program.

2.3.1 Organization and Scheduling

The licensee implemented the surveillance testing program under PAP-1105, "Surveillance Test Control." This procedure described the organization, responsibilities, and program controls in effect to ensure that required surveillance testing was completed in a proper and timely manner.

The Technical Specification Surveillance Instructions (SVIs) were developed and maintained by Technical Administrative Procedure TAP-0503, "Preparation of Technical Specification Surveillance Instructions." Full coverage of Technical Specification surveillance requirements was tracked by using the Technical Specification/Surveillance Instruction Cross Reference Matrix maintained by the Surveillance Coordinator.

Surveillance testing was scheduled by the repetitive task function of the Perry plant maintenance information system (PPMIS), which tracked the required due dates for surveillance testing for each piece of equipment. The scheduling algorthms included the grace periods allowed by the Technical Specifications, and provided a due date and a late date for each test. A review of the surveillance completion records for all safety-related surveillance tests performed during the period December 1, 1987 through March 15, 1988 verified that no test had been performed late because of a scheduling error and that partially completed tests were not treated as fully completed for subsequent surveillance test scheduling. All tests noted to be past their late dates were late because of improper plant conditions, inoperable equipment, or relief granted by the NRC.

The surveillance test tracking performed by PPMIS was backed up by semi-automated means to ensure that the required test due dates would not be lost if there was a failure of the PPMIS. This backup tracking function, performed on a personal computer, appeared to be effective. The data base was updated daily, and the resulting test listings were validated against the comparable PPMIS data. Another function of the personal computer system was to produce the weekly test schedule and operational condition change checklist.

A master SVI book was maintained in the control room, and was used by the control room staff to track the status of scheduled SVIs. Besides the scheduled SVI list, this book also contained a matrix which cross-referenced surveillance tests with their respective Technical Specifications, and the Operational Condition Change Checklist. The Operational Condition Change Checklist, maintained under the control of PAP-1114, "Operational Condition Change Checklist," provided the operators a summary of all required SVIs coincident with a change in plant operational condition. This method of tracking condition-dependent SVIs appeared effective.

PAP 1105, "Surveillance Test Control," and PAP-1101, "Inservice Testing of Pumps and Valves," required that completed pump tests be reviewed by the control room staff and the cognizant surveillance coordination and engineering staff within 96 hours of test completion, and recommended that valve tests be reviewed within four working days of test completion. In the team's review of completed tests, the team noted that all test reviews were performed within the required or recommended period, including nonpump and valve tests. The timeliness of test review was noted to be a strength but the post-test technical data reviews and analyses of trends appeared to be somewhat shallow, especially in cases where inconsistent or anomalous data were obtained. Further elaboration of this weakness is presented in section 2.3.2.

2.3.2 Surveillance Procedures

Several surveillance test procedures were reviewed for technical adequacy, rigor, and usefulness. In general, the procedures were well written and appeared to test the required functions.

The inspection team noted, however, one instance in which the omission of a required procedural step resulted in obtaining incorrect stroke times for containment isolation valve 1E12-F021 (RHR C test valve to suppression pool). During performance of test E12-T2003, "RHR C Pump and Valve Operability Test," Revision 5, the subject valve had erratic stroke times over a period of several months. On December 14, 1987, 1E12-F021's measured stroke time was 22 seconds; the previously determined normal stroke time for this valve was about 78 seconds, with a maximum allowable time of 90 seconds. Because of the variation, the cognizant inservice inspection engineer increased the stroke-time test frequency from quarterly to monthly, and wrote a work request to have the stroke-time disparity investigated. The following data were obtained during four successive stroke-time tests of valve 1E12-F021:

12/14/87	22 seconds
01/21/88	21 seconds
01/25/88	78 seconds
02/29/88	77 seconds

Review of test E12-T2003 and associated data packages from the dates listed above showed the apparent cause of the erratic stroke times to be a lack of clarity in the wording of the surveillance instructions, which, if followed verbatim, would result in the subject valve being stroked from a throttled, instead of fully open, position. It appeared as though the operators who performed the tests on December 14 and January 21 followed the procedure verbatim, while the operators who conducted the tests of January 25 and February 29 were knowledgeable enough to fully open the valve prior to stroking; however, PAP-1105 requires the tests to be performed in a step-by-step sequence unless deviation is specifically authorized in each surveillance instruction. The operator who performed the test on January 25 recommended that the procedure be modified to have valve 1E12-F021 fully open prior to stroking in order to obtain a valid stroke time. In response to team concerns the licensee developed and implemented the requested procedure change while the inspection team was onsite.

The inspection team had the following concerns as a result of the problem: inadequate procedure used to demonstrate operability of a containment isolation valve, repeated deviation from the SVI procedural steps, no staff action to correct procedural deficiency for a period of more than seven weeks, and lack of aggressive investigation of the erratic stroke time of the valve in question.

Another case of inadequate review of valve performance data was observed by the team during review of historical stroke-time data. The team noted that the stroke time for valve 1B21-F067C underwent an increase of more than 400 percent following the motor-operated valve analysis and testing system (MOVATS) testing. On May 28, 1987, the subject valve's measured stroke time was 5 seconds. Work order (WO) 87000402, issued for this valve on July 21, 1987, required that the valve's remote position indication limit switches be reset per Generic Electrical Instruction (GEI)-14, "Limitorque Limit/Torque Switch Adjustment," in concert with MOVATS testing per GEI-56, "Motor Operator Valve Analysis and Testing System (MOVATS) Testing." Following completion of WO 87000402 the measured stroke time was 21 seconds. It should be noted that the valve's maximum allowable stroke time was 22.5 seconds. The licensee's method for measuring stroke time, as specified in PAP-1101, was to measure the time required from valve actuation switch positioning until receipt of the proper light indication in the control room. It appeared evident that the pre-MOVATS stroke times for valve 1B12-F067C were based on erroneous limit switch settings. The licensee was unable to provide the inspection team with pre-MOVATS data demonstrating where the position indicating limit switches were set for this safety-related motor-operated valve (MOV). Further, the licensee was not able to definitively show where the corresponding limit switches were set for any other safety-related MOVs which had not undergone MOVATS testing and the associated limit switch resetting. At the time of the inspection, the licensee had performed MOVATS testing on about one-half of the plant's safety-related MOVs, with the remaining MOVs to be tested by the end of the first refueling outage, which was scheduled for the first quarter of 1989. This item was turned over to Region III for followup. See NRC inspection report 50-440/88004 for the details of that followup.

The team's major concern resulting from this issue was that for those valves which had not undergone MOVATS testing, Technical Specification surveillance stroke timing was being performed based on unknown MOV position indication limit switch settings. Secondary concerns arising from this issue were that an in-depth investigation into the dramatic rise in stroke time had not been performed. As a result, the generic problem of unknown and potentially inaccurate MOV position indicator limit switch settings was never addressed. The licensee had initiated action to confirm these limit switch settings prior to the time the team left the site.

Staff development and verification of surveillance tests were also inspected by the team. In particular, two licensee programs were reviewed: the yellowline review and the currency review. The main purpose of the yellowline review program was to verify that the channel and system logic specified in Technical Specification section 3/4.3, "Instrumentation," was tested properly and that the sequential and overlap testing described in the surveillance instructions adequately met the requirements of the Technical Specifications. The main purpose of the currency review program was to perform a one-time review of all surveillance tests to ensure that applicable Technical Specification requirements were adequately addressed, to verify the technical adequacy of the tests,

and to identify and correct any undesired plant actuations or isolations caused by the tests. Both these programs appeared to be implemented in a meticulous manner and seem to be achieving their stated objectives.

2.3.3 Surveillance Tests Witnessed

The following surveillance tests were witnessed by the team:

B21-T0032C "Reactor Vessel Steam Dome Pressure High Channel C Functional Check," Revision 3,

B21-T0369B "Safety/Relief Valve Pressure Actuation Channel Functional for 1B21-N688B," Revision 2,

C51-T0027E "APRM Trips Channel E Functional Check," Revision 2,

D17-T8051 "Offgas Vent Radiation Monitor Functional Check," Revision 3,

E31-T5395A "RHR/RCIC Steam Line Flow High Channel A Functional," Revision 1,

R43-T1318 "Division 2 Diesel Generator Start and Load," Revision 2.

These surveillance tests were satisfactorily performed by on-shift operations personnel in accordance with approved, implemented procedures. The test personnel appeared to have a comprehensive knowledge of the surveillance procedures, test equipment in use, and equipment responses during conduct of the tests.

2.4 Management Oversight and Safety Review

The general functions of engineering, committee activities and independent safety evaluations were reviewed with respect to their roles of providing operational overview and support.

The plant is operated by the licensee's Nuclear Group, headed by the Nuclear Vice President who reports to the Chairman of the Board, and the Nuclear Group Vice President, who reports to the company President. The operating organization consists of five major departments: Operations, Technical, Nuclear Engineering, Quality Assurance, and Project Services. Day-to-day engineering support is provided by the Technical Department, with design engineering and related functions supplied by the Nuclear Engineering Department. The Independent Safety Engineering Group (ISEG) is part of the Reliability and Design Assurance Group of the Nuclear Engineering Department.

The team's evaluation focused primarily on the ISEG, the corporate Nuclear Safety Review Committee, the on-site Plant Operations Review Committee, and the Nuclear Steam Supply System (NSSS) Engineering Unit of the Technical Department. The principal attributes considered were the organizational structure, personnel and staffing, and definition and implementation of the organizational functions. The organizational structure was reviewed to determine that it was prescribed by corporate policy documents, that its functions were adequately defined by charter documents and procedures, and that staffing and staffing plans were adequate to fulfill the chartered roles. The status of the implementation of major organizational functions was determined by

reviewing the procedures that were in place to fulfill charter functions; reviewing procedure implementation records; and interviews and discussions with licensee managers, supervisors, and staff personnel inside and outside the departments of interest. Implementation of selected functions such as interdepartmental communications, plant engineering support, and problem resolution was assessed by reviewing licensee activities and plant problems occurring during the inspection. Team member observations of plant equipment and operational activities during the day shift and the backshift in the control room and plant areas were included.

2.4.1 Goals, Objectives, and Staffing

The primary sources of policy, goals, objectives and implementation requirements were the top tier Perry Operations Procedures (POPs) Manual and the second-tier Operations Manual Plant Administrative Procedures (PAPs). Selected POPs and PAPs that were reviewed with respect to management oversight and engineering support are discussed below.

The details of the procedures and individual department and group staffing levels and plans were discussed with licensee management and staff. Particular emphasis was given to review of the NSSS Engineering Group and the ISEG. Each group was found to have a well-defined charter with specific roles defined for subunits.

The Technical Department functions were specified by POP 0103, "Organization of Perry Plant Departments," Revision 0, and PAP-0101, "Perry Plant Operations/ Technical Department Organization," Revision 3. The team was advised that a pending Revision 4 to PAP 0101 would authorize restructuring of the existing mechanical, electrical and inservice inspection testing units and that a transition to the new organizational structure was in progress. The team concluded that the new structure should meet the corporate objectives and fulfill assigned functions. Staffing levels were found to be consistent with licensee plans, subject to routine personnel rotations and short-term variations.

ISEG functions were specified by Technical Specification 6.2.3, "Independent Safety Engineering Group"; Updated Safety Analysis Report (USAR) Section 13.4.3, same title; POP-0203, "ISEG Operations," Revision 0; and Nuclear Engineering Department Procedure NEDP-0201, "ISEG Conduct of Operations," Revision 2. The above procedures were found to adequately reflect the license requirements. The ISEG staff consisted of the General Supervising Engineer for Reliability and Design Assurance as Chairman, a full-time ISEG Supervisor, and five ISEG members on one year rotational assignments from other departments. Discussions with ISEG managers indicated that the rotational engineer assignments had adversely affected the group's continuity, and longer rotations or permanent assignments were being contemplated.

Failure and root cause analyses were performed by the ISEG, the Technical Department and other organization units. Although PAP-1601, "Failure Analysis," Revision 1, provided a general assignment of responsibilities and processes, the licensee had not yet adopted specific failure analysis or root cause determination methods nor implemented personnel training. The licensee appeared to be aggressively pursuing development of techniques and training to improve this function and had formed a multidepartment task force to guide this

development. The task force was targeted to implement the plan through initial personnel training in May 1988. The team reviewed the task force's resource material and found it extensive and representative of industry state of the art. Several trial-use programs were in progress on current ISEG projects, including the use of condition/event charting, barrier analysis, and change analysis.

The team reviewed the qualifications and training of incumbents in ISEG and Technical Department positions and determined that educational credentials, prior professional experience and plant (or plant-type) experience was acceptable. In nearly all cases, the Technical Department Systems Engineers were degreed engineers with extensive in-plant experience gained during test programs at Perry or contemporary boiling-water reactor facilities. This resulted, with a few individual exceptions, in the engineers having especially good technical credibility, which was relied on by the operating staff. The ISEG staff possessed similar qualifications, with several of the members having design-oriented backgrounds. Interviews with plant staff indicated that ISEG had previously not enjoyed good credibility or rapport with the operating organization, largely because of the group's prior organizational staff. ISEG's early (circa 1985-86) projects were viewed by the staff as insufficiently rigorous, unnecessarily negative, and with low-to-moderate constructive output. Recent changes in ISEG operating philosophy appeared to be correcting this negative image.

The team reviewed plant and job-specific training for a sample of Technical Department and ISEG personnel. The licensee was participating in the Institute of Nuclear Power Operations (INPO) training accreditation program for "Technical Staff and Managers (TSM)". The team reviewed the training status with respect to the licensee's Final Safety Analysis Report (FSAR) and Updated Safety Analysis Report (USAR) commitments and the plant Training Manual and found that the progress to date was consistent with the licensee's commitments. This training program involved 11 courses, including plant reference materials, codes and standards, QA/QC, physical sciences and engineering, and plant systems and integrated operations. This program was still largely under development during the inspection and was scheduled for presentation to INPO in June-July 1988. Only two versions of the plant systems training course (five-week and one-week courses) had been available and conducted. About one-half the targeted staff had received either one or the other of the two courses. As a result, training for about 75 percent of the staff members reviewed had been limited to "required reading" of procedures and unstructured on-the-job training. All the staff members in the groups of interest were identified for eventual participation in the training program. The licensee's training program also required development of departmental specific training plans to supplement the general training. These plans were not yet under development. Some equipment-specific or task-specific training had been provided and was planned for the future on a case-by-case basis upon request by line management.

2.4.2 Systems Engineering

As previously mentioned, the NSSS Engineering Group was the focal point of this portion of the inspection. This group provides the principal day-to-day engineering support function for the plant operating staff. The engineering support interface with operational activities appeared to be well-integrated. The systems engineering responsibilities included system troubleshooting and

problem investigation support; root cause analysis; work order initiation, review, and retests; surveillance and inservice test results review; condition report and licensee event report investigation and review; preventive maintenance reviews; design change participation; and involvement in industry and plant experience reviews.

Maintenance and work order related functions of the group were reviewed along with the team's inspection of maintenance activities as discussed in Section 2.2 of this report. There were no unacceptable findings related to the NSSS Systems Engineering Group's support of maintenance.

Similarly, functions of the group related to surveillance and inservice testing were reviewed as part of the inspection discussed in Section 2.3 of this report. Two examples of reviews involving questionable or unsatisfactory valve testing data are discussed in section 2.3 and attributed to the Technical Department.

The team interviewed NSSS Engineering Group supervisors and staff engineers, and reviewed recently completed and ongoing handling of plant problems, condition reports, licensee event reports, and experience reports. In most cases, the implementation of the required functions was found to be adequate. The group had issued "Plant Engineering Guidelines" as departmental desk-top instructions for the administration of key activities, such as technical reviews and equipment performance assessment. The group appeared to be generally rigorous in their approach to their functions. For example, review of records for the problem of the slow opening stroke of the main steam isolation valve (MSIV) that occurred during the inspection and prior problems with MSIV air-actuated solenoid valves indicated generally good techniques, including maintenance of investigation journals, use of internal and external vendor resources and assignment of priorities. Interviews with plant operations personnel indicated a generally high level of confidence and reliance on the group's personnel. The inspection team also conducted a sampling of licensee management reviews of operating experience reports, condition reports, licensee event reports and related investigations. Licensing and compliance engineers and systems engineers were interviewed, reports were reviewed, and methods were evaluated. In general, the System Engineering Group appeared to be well-founded and generally well-administered. Routine activities appeared to be handled satisfactorily. The Group had good credibility with the plant operating staff, and the personnel were experienced. The Systems Engineering Group appeared to have matured quickly, and it provided a positive contribution to the organization.

One problem, which involved apparent intra-system leakage and caused overheating, steam binding, and a water hammer in the piping of the residual heat removal (RHR) system's shutdown cooling loop, was followed by the team throughout the inspection. The licensee's handling of this problem was considered weak. In this case, the team found the group's approach less than rigorous, especially in comparison with the handling of other recent, similar activities.

The problem was initially identified on about March 10-11, when damaged RHR piping supports were found. The team began review of the licensee response to the problem on March 15 and requested that the licensee present plans for resolving the problem at the earliest opportunity. Also on March 15, a systems

engineer issued a memorandum to the operations department recommending interim measures to periodically flush and cool the piping and to collect data for additional evaluation. Data collection and licensee internal discussions continued through about March 17-18 when Nuclear Engineering Department (NED) assistance was requested by PPTD. Additional details of these activities are discussed in Section 2.1 of this report. Although the systems engineers provided more formalized flush and cooldown data collection instructions on about March 18, the licensee did not appear to have developed either a detailed plan for continued investigation or a plan for corrective action by March 21-22.

On March 21, a team member observed venting of condensate transfer piping connected to the RHR system in an apparent attempt to identify the source of high-temperature leakage. The systems engineer in charge in the RHR "B" room was directing plant operators in venting portions of the systems. Two venting evolutions occurred. During the first venting from the condensate transfer system, loud water hammer noises were heard and were mistakenly thought to be coming directly from the piping being vented. After several minutes of consideration, the systems engineer directed the second venting to begin. About five minutes after venting began, another loud water hammer was heard that eventually was localized in reactor water cleanup (RWCU) and condensate transfer common piping. During the venting, piping high temperatures taken with hand-held instruments and steam vented from the system drain valve were unexpected and were initially discounted by licensee personnel. The licensee subsequently identified another suspected intra-system leakage path from the high-temperature portion of the RWCU system and the condensate transfer common piping. The team member observed that the licensee personnel on the scene did not appear to have clear objectives for the evolution, did not have a procedure at the work scene, did not rigorously evaluate the anomalous vent flow and temperatures observed, and continued the evolution without further review or management consultation after obtaining initially unexpected results.

As a result of the above observations and the apparent lack of an overall licensee response plan for the problem, the inspection team requested a meeting with the Technical Department staff on March 23 to obtain additional information. During this meeting, the team expressed concerns regarding the apparent lack of urgency in developing a corrective action plan, the informality of observed activities to date, the lack of information available to the team, and the licensee's evaluation of potential safety significance of the problems. The Technical Department staff advised that their recommendations had been referred to the Nuclear Engineering Department for evaluation and approval during the week of March 14 and a response was expected that day. The team was presented a one-page investigation plan outline transcribed from the cognizant manager's office blackboard. This plan involved removal of insulation from the affected piping to increase heat losses to the environment and thereby minimize the frequency and extent of the required system cooldown flushes. The plan did not address detailed diagnosis or eventual repair of the leakage paths.

Review of the lead engineer's and systems engineer's problem files revealed historical review documents and working notes but little evidence of a pre-planned approach that would lead to a comprehensive corrective action. Additionally, the NSSS Engineering Group's resources seemed somewhat strained by the several high-priority workloads occurring during the period; this workload included this inspection, problems with MSIV C slow opening stroke times, and a

leaking high-pressure core spray (HPCS) pump seal. The team considered this workload to be unusual but not extraordinary and was concerned with the group's inability to absorb such workloads with currently assigned resources. Although the overall site staffing was similar to that of comparable single unit sites, the assignment and alignment of resources for in-process problem support may warrant licensee reevaluation.

Another problem was evident in the licensee's application of procedural controls to this problem. As previously mentioned, on March 15 the Systems Engineer issued a memorandum listing various general actions to be taken to periodically vent and flush the RHR piping to reduce temperatures and avoid water hammer on routine and emergency RHR system initiation. These memorandum instructions were expected to be superseded within a day by a new temporary instruction (TXI). The Operations Department, however, issued the memorandum to the control room as part of the daily instructions (night orders) of March 15-16 and subsequently used the general guidance of the memorandum to begin 1-hour duration flushes of the RHR system on a once-per-shift basis. This flushing was accomplished by applying temporary instruction TXI-50, "Reduction of E12 (RHR) Pressure to Compensate for Backleakage" Revision 0. As written, TXI-50 provided "...the directions for reducing excess pressure in the RHR System..." and included directions for momentarily venting the system to reduce excess pressure down to normal keep-fill system pressures of 40-100 psig. In the circumstances discussed above, excess pressure was not the primary problem but rather progressive heating of the RHR loops to above saturation temperature. The TXI-50 flow paths were used to establish a flush from the alternate keep-fill source, condensate transfer, rather than the normal RHR waterleg pumps as specified by TXI-50, to the suppression pool.

The team reviewed the flow paths and methods used by the licensee and found them to be acceptable but was concerned that a staff memorandum and daily instructions were used, in effect, to revise an approved operating instruction without benefit of the normally required reviews and approvals appropriate to a procedure-intent change. This matter was discussed with the Senior Operations Coordinator and the staff, noting that the practice appeared to be an isolated case but could provide the potential for operational evolutions without proper technical review and management authorization. Subsequently, on March 18, 1988, the licensee issued TXI-54, "Monitoring and Review of RHR Loop A and B High Point Temperatures for Potential Steam Voids," Revision 0, which substantially revised and formalized the guidance initially issued in the memorandum.

2.4.3 Independent Safety Engineering Group (ISEG)

Technical Specification 6.2.3 provided for the composition and functions of the ISEG, including examination of specific subjects "which may indicate areas for improving unit safety." The ISEG was further required to make detailed recommendations for such improvements. These requirements were amplified by USAR Section 13.4.3. The Group's charter and operating procedures were provided by NEDP 0201, "ISEG Conduct of Operations," Revision 2.

The ISEG was chaired by the General Supervising Engineer, for Reliability and Design Assurance, and had a full-time supervisor reporting to the chairman. Five full-time members were degreed engineers who met the composition requirements for the Group. ISEG supervisor and member qualifications and training records were reviewed and found to be acceptable. The Group functioned in

three principal roles. Ten to 12 major "projects" were selected for examinations annually, using a management screening and approval mechanism. Additionally, one member of the group was assigned on a monthly basis to perform surveillance of operating and maintenance activities. These two activities resulted in a series of project reports that described the activities and made formal recommendations. The third activity was a less-well-documented review of individual "current events" and industry awareness material that came to the attention of the Group but did not warrant the status of a "project." Examples included procedure and experience report reviews done by a subcommittee of the Nuclear Safety Review Committee (NSRC), participation in response development for NRC, INPO, and the owners group, and other operating experience input reviews.

The team reviewed the ISEG project listing (1985-88), project and surveillance reports and detailed recommendations. The project reports generally indicated a rigorous review process and included valid recommendations. The team noted that major projects during 1987-88 averaged about two per ISEG member per year, not including the operations surveillances. The overall volume of output and correspondent safety impact appeared to be low compared with ISEG output at other comparable facilities. Also, the ISEG apparently continued development of findings beyond initial problem identification to the preparation of recommended solutions, although these solutions were frequently a broad spectrum of recommended actions (see below). Group effectiveness could possibly be improved by changes in project selection strategy and the level of resource investment in a single project. Such changes might result in more timely evaluation of more issues. Timeliness of ISEG reports and findings is further discussed below.

In contrast to the more rigorous individual project reports, the operations surveillance reports tended to be more a narration of the month's operational and maintenance related activities and events than an "independent verification that these activities were performed correctly," as required by Technical Specification 6.2.3.3 and USAR Section 13.4.3. Only 12 recommendations (findings) were issued during 1987 as a result of these surveillances. Of those issued, only five had been issued at the time of this inspection. Discussions with ISEG management and interviews with ISEG member engineers indicated that the reports may not have been representative of the actual verification and recommendation efforts. The licensee advised the team that potential recommendations and findings that were routinely addressed and closed during a given month were not typically discussed in the reports.

The team noted that the ISEG operational surveillances were similar in scope to those being performed by the QA Department but did not appear to have the rigor and critical approach of the QA surveillances. The licensee stated that the reports did not accurately represent the rigor of the verifications performed and that the format would be evaluated for improvement. The team further noted, however, that the surveillances appeared to be accomplished without benefit of a preplanned checklist, except for a general guidance listing informally issued by the ISEG Supervisor. It was not clear that the intent of the Technical Specifications was being fulfilled by this activity, and this was considered a weakness by the team.

At the time of this inspection, four of eight "project reports" for 1987 had not been issued. This lack of timeliness was also observed to have affected the impact and response to the Group's recommendations. Most of the 1987 issued recommendations remained open awaiting response or action from the receiving departments. The team also noted that through 1986 into 1987, ISEG's findings tended to be more programmatic than technical and frequently broad in scope; for example, Project Report 86-008, "Plant Electrical Operating Practices," made eight broad recommendations for major procedure and design changes and reevaluation of operating practices. Six of the eight recommendations remained open at the time of this inspection. Interview results indicated that this approach resulted in low priorities being assigned by responding organizations because of the resources needed to respond being directed to more contemporary and manageable tasks.

The open recommendations were tracked on the station-wide computerized Commitment Tracking System; they were not treated by the licensee as firm action commitments, but rather as nonbinding recommendations. The poor reporting timeliness and open recommendations had been identified as problems in the "ISEG 1987 Annual Report" to senior licensee management. Although the ISEG management had identified corrective actions, such as detailed report scheduling and recommendation followup to improve performance, no material improvement had occurred, and the ISEG Chairman and Supervisor were considering other possible remedies. The team considered the above circumstances to be significant detractions from the Group's effectiveness.

One of the ISEG minimum performance requirements specified by NEDP 0201, Section 1.2, was ISEG evalution of the effectiveness of the operational Quality Assurance Program, independent of normal functions of the Quality Assurance Department. This was construed by ISEG management to mean QA program activities intrinsic to the other activities being examined by ISEG. The team agreed with this interpretation and believed that review of QA activities concurrent with other technical subject reviews was a worthwhile and workable approach. The projects undertaken and surveillances conducted, however, with one exception, reflected essentially no consideration of QA activity evaluation. Although a number of the ISEG findings involved QA program concepts, such as document control, corrective action programs, and administrative procedures, these findings were almost never presented in a manner that related the findings or recommendations in a QA context. Similarly, no evidence was found to indicate that a methodical approach to QA concepts was considered in project planning and implementation. One project report did concentrate on spare parts procurement and material control aspects. Several ISEG collateral duties, such as procedure reviews, operating experience report reviews, and initiation and review of condition reports, represented partial fulfillment of the requirement but were not consistently documented. This aspect of the charter procedure was also not clearly evident in the Group's strategic project planning. The ISEG Chairman and Supervisor acknowledged this evaluation and stated that fulfillment of this function would be reevaluated and adjusted as necessary.

The ISEG was participating in the interdepartmental task force for establishment of a site-wide failure and root cause analysis process. The team found that ISEG was using various analysis methods on a trial basis for ongoing reports. The team reviewed draft project report "Root Cause Analysis of CR 88-020 Using Events and Conditions Charting Method," dated March 22, 1988. This report

evaluated problems with frazil ice fouling lake water intakes in January 1988 and was a commendable first effort in applying systematic failure analysis methods. The inspection team considers this to be a positive indicator of the licensee's intent to improve problem analysis methods.

2.4.4 Plant Operations Review Committee (PORC)

The team evaluated review activities of the Plant Operations Review Committee (PORC) through inspection of procedures and meeting minutes, discussions with PORC members, and attendance at a scheduled meeting. The PORC activities observed exhibited several strengths that make the committee effective in reviewing plant procedures, modifications, and operations.

PAP-0103, "Plant Operations Review Committee," Revision 3, provided a description of PORC membership, responsibilities, authority, conduct of activities, review subjects, and reporting requirements, and provided the charter for the PORC. The delineated responsibilities, memberships, and quorum requirements in PAP-0103 were consistent with Technical Specification 6.5.

PORC members are designated in Technical Specification 6.5.1.2 by organizational title. The licensee did not permit a member or alternate to vote or count toward a quorum unless the member had been qualified through completion of a comprehensive reading and study program. The inspector reviewed the training program status for all current members and alternates. The training program included approximately 205 procedures and documents, along with all current temporary procedure changes. Completion of the program was closely tracked. Once initial qualification was complete, the individual received a periodic printout showing those procedures and documents in the original program that had been revised. In this way, each member was made aware of the current issue of each of the applicable governing documents. At the time of this inspection, three designated PORC members were still undergoing qualification. At the time of this inspection, 5 of the 21 qualified members and alternates had training status records showing incomplete review items over one month old. The oldest item had an effective date of June 1, 1987. In response to the inspector's question, the PORC chairman stated that no policy or guideline had been established for disqualifying members from voting when update training became delinquent.

Technical Specification 6.5.1.6.f requires that PORC review all violations of Technical Specifications. The team selected two sources of violation reports to confirm that PORC had reviewed a sample of such items identified in calendar year 1987. The first of these sources were three violations identified in NRC Inspection Reports 50-440/87-04 and 87-12. Since NRC inspection reports were not routinely sent to PORC for review, these violations were not addressed in the context of Technical Specification violations. The team confirmed, however, that the violations were in fact reviewed as Licensee Event Reports (LER) 87-11, 87-17, and 87-48.

Another source of violation reports was the licensee's Condition Report System, described in PAP-0606, "Condition Reports and Immediate Notifications," Revision 5. This system was selected for review because it should include those violations that may not have resulted in an LER, such as violations of Technical Specifications Section 6, "Administrative Controls." Condition reports documented and provided for the investigation, notification, and

reporting of potentially reportable events. The condition report also provided for reporting abnormal plant conditions or events that required further action and review by plant staff. The criteria for initiation of a condition report were found in PAP-0606; they specifically included Technical Specification violations. During the evaluation review process, the compliance engineer was required to screen all condition reports for PORC review. This screening was designed to ensure that, among other items of interest, Technical Specifications violations, particularly Section 6, were sent to PORC for review.

The team selected 12 condition reports which documented missed surveillance tests to confirm review by PORC. In no case had the condition report been forwarded to PORC for review. The licensee stated that a missed surveillance test did not constitute a violation unless the associated "Limiting Condition for Operation and Action Statement" were not met. While this approach was consistent with Technical Specification 3.0.2, it denied PORC an opportunity to evaluate the frequency and causes of missed surveillance tests. The evaluation that resolved each of the 12 condition reports reviewed concluded that no Technical Specification violation had occurred.

The team member involved attended scheduled PORC meeting 88-039, held on March 17, 1988. Attendance was ample to meet quorum requirements, and nearly all material for consideration had been distributed to PORC members and alternates earlier in the week. Licensee practice has been to require that review material be available for distribution to members on the Monday preceding the scheduled weekly meetings on Thursday. Only one nonscheduled item was addressed as a walk-in at the meeting observed by the team member. The team member found that PORC members were inquisitive, and good interchanges occurred at the meeting. Agenda items were reviewed in advance of the meeting, with the result that minimal briefing time was necessary by the item sponsor. PORC activities were a strength but could be improved by addressing the potential for missed reviews discussed above.

2.4.5 Nuclear Safety Review Committee (NSRC)

Activities of the Nuclear Safety Review Committee were evaluated through review of the charter and meeting minutes, discussions with personnel, and attendance at a scheduled meeting of the full committee. The NSRC Charter, Revision 4, dated January 14, 1987 provided overall guidance for functions of the Committee. The Charter was supplemented by five guidelines, titled as follows:

001 Administrative

002 Operations and Maintenance Subcommittee

003 Radiological Environmental and Chemistry Subcommittee

004 Audit and QA Subcommittee

005 Engineering Subcommittee

The purpose statement of Guideline 001 stated that the Guideline was not a mandatory requirement. Guideline 001 was, however, the only document that stated the Technical Specification 6.5.2 requirements for NSRC member

qualifications, quorum, and meeting frequency. Taken in the aggregate, the Charter and Guideline 001 conformed to Technical Specifications 6.5.2 requirements covering NSRC activities and membership. Although the Guideline 001 procedures were stated to be optional, the team found that NSRC operated in accordance with them.

Guidelines 002 through 005 described the activities of the four standing NSRC subcommittees. The majority of the NSRC review effort was accomplished in the subcommittees, which met bimonthly during the intervening period between the bimonthly full committee meetings. Each subcommittee reported to the full NSRC at meeting No. 45 held on March 16, 1988. An inspection team member attended this meeting.

At meeting No. 45, there were informative presentations, good discussion, and active interchange among the members. Agenda item material was distributed to members in advance to allow prior review before decisions were made at the meeting. One apparent exception to this early review process was that a revised version of a Technical Specification amendment request had not been distributed to all members.

To confirm conformance with Technical Specification requirements, the team verified member qualifications, audits and the review process used to ensure that necessary items received NSRC review. Based on a qualification matrix prepared by the licensee, some level of expertise in each of the areas listed in Technical Specification 6.5.2.2 was evident among the members. With respect to audit areas in Technical Specification 6.5.2.8, the inspector reviewed an audit and QA Subcommittee report dated March 7, 1988. Attachment 3 to that report listed QA audits completed during 1987. The reports were listed under NSRC audit areas consistent with those in Technical Specification 6.5.2.8. The NSRC participated in audits at one of three levels: Category A were NSRC-led audits, Category B were QA audits with NSRC participation, and Category C were QA audits reviewed by NSRC. All required audit areas were covered and tracked by the subcommittee.

The inspection team reviewed NRC inspection reports, PORC minutes, condition reports, safety evaluations, and LERs. All NRC inspection reports and LERs were routinely routed to all NSRC members. In addition, Guideline 002 required that the Operations and Maintenance Subcommittee review NRC inspection reports and LERs, as well as PORC minutes and safety evaluations. Those items selected for review were evaluated in detail and documented in the subcommittee report to the full NSRC. The team noted, however, that no evident mechanism had been established to ensure that all PORC minutes, LERs, and safety evaluations were provided to the subcommittee for review.

Condition reports were reviewed by the Engineering Subcommittee; however, only closed condition reports, were reviewed. This practice created the possibility that particularly difficult problems might not come to the attention of NSRC. An additional concern in this area was the lack of a mechanism to ensure that all closed condition reports were submitted to the Engineering Subcommittee for review.

In general, NSRC conducted detailed and informative reviews. While no examples were found of failures to evaluate an LER, a Technical Specification violation, a set of PORC minutes, or a safety evaluation, the practices employed by NSRC

and its subcommittees provided the potential for missed items and should be reviewed for adequacy.

2.5 Quality Programs

The team conducted a review and assessment of the licensee's Quality Assurance and Quality Control program and organization. Included in this review and assessment were the conduct and reporting of audits and surveillances, inspections of quality-related activities associated with work orders and repetitive tasks, qualification of auditors and inspectors, and the trends emerging from followup on quality organization findings. In addition, the team reviewed the licensee's corrective action program for overall effectiveness.

2.5.1 Quality Assurance (QA)/Quality Control (QC) Involvement Findings

The quality organization included an operational section, a procurement and administration section, and a maintenance and modifications section. Each section reported to the Nuclear Quality Assurance Department (NQAD) manager who reported to the Vice President, Nuclear.

2.5.1.1 Quality Audits and Surveillances

The operational section was, in part, responsible for auditing administrative, operations, and technical support activities for implementation and adequacy, reviewing plant operations manuals, procedures, and instructions, as well as conducting surveillances of plant operations activities and providing support for plant-related maintenance and modification activities.

2.5.1.1.1 QA Audits

The team reviewed the 1988/1989 audit schedule that had been issued to plant management on December 9, 1987. This schedule, which was reviewed by the NSRC QA Subcommittee, was required to include all audits specified by section 6.5 of the Perry Technical Specifications, FSAR, commitments, and the QA plan. The team reviewed the audits required by the Technical Specifications and found that they were included in the audit schedule. A comparison with the audits specified in Table 18-1 of the QA plan, however, revealed several discrepancies between the plan and the audit schedule. When this inconsistency was brought to the licensee's attention, the team was given a QA plan change request form that was initiated on November 10, 1987. The change request form was approved during the OSTI inspection. This change brought the audit schedule into compliance with the QA plan. The change request was also found to comply with the audit frequencies identified in NRC Regulatory Guide 1.33 which endorses ANSI N18.7.

From a list of the previously conducted audits, the team selected and reviewed five audit packages. The team verified, through discussions with applicable QA personnel and review of the audit packages, that the audits covered appropriate areas, were sufficiently technical in nature, and resulted in meaningful findings that were adequately reported. The team noted that deficiencies were identified as action requests and followup occurred as prescribed in the QA manual. A review of selected action requests indicated that management was making adequate disposition of action requests received from the QA audit teams. In addition to action requests, the audit reports often made

recommendations that were not specifically related to deficiencies. The team found these recommendations to be a valuable management tool that could result in improved programmatic performance. A review of management followup on a sample of these recommendations revealed that management usually addressed these recommendations; however, there was no formal program in place to ensure that they were being addressed. A recent change in the way recommendations are addressed should result in significant improvements in this area, since plant management is now requested to respond in writing to each recommendation.

During the team's review of audit report PIO 87-25, "Technical Specifications," the team identified an item addressed in section IV.4.e of the audit report that was not adequately pursued by the auditors. This item concerned the lack of response time testing of an affected circuit or component when the component was replaced in a circuit that required periodic response time testing by Technical Specifications. The auditors noted the item but dismissed it based on looking at the results of several response time tests completed recently with no evidence of test failures because of faulty components. The auditors were interviewed and asked to identify the specific work order(s) they reviewed that resulted in the identification of this specific concern. The work order that was produced was for a component (relay) that was not related specifically to a circuit that required response time testing. With lack of a specific example, the team interviewed the instrument and control (I&C) engineering supervisor and was informed that circuitry or component response time testing would not automatically be required if a component was replaced with a like-for-like component in a circuit that required response time testing. The I&C engineering supervisor stated that relays, or other components with vendor certifications that identify the components as having very short response times, would have little or no effect on overall circuit response times. In these cases, the supervisor stated that a functional test may be all that would be required to consider the component and associated circuit operational.

The team informed the licensee that to rely solely on vendor certifications for the response time attribute of a component associated with a circuit requiring response time testing was nonconservative and represented a weakness in the post-maintenance testing program. For example, NRC inspection report 440/86012 identified a relay in the neutron monitoring system that did not meet the actuation time specified in its vendor certification.

Subsequently, the USTI team was informed that the licensee was developing a program for bench-testing Agastat relays (EGP type), if they were to be used to replace relays in a Technical Specification response time loop, to ensure that the relays operated within the vendor specified response time. In a memorandum from the Acting Manager of the I&C Section to Perry Licensing, dated March 24, 1988, it was stated that a procedure will be developed for delineating how and when these relays would be tested.

Audit Report PIO 87-12 "Effectiveness of Corrective Action," was reviewed by the team and was found to be particularly outstanding in both its depth of review and the significance of its findings. The corrective actions taken by management to resolve the findings identified in this audit report are discussed in section 2.5.2 of this report.

The team's review of the qualifications of selected auditors indicated that the auditors were well-qualified and, in all cases, exceed the regulatory and plant requirements for the positions held. In addition, technical specialists and outside consultants were used during selected audits to enhance the technical knowledge of the audit team when the need was identified.

2.5.1.1.2 QA Surveillances

The team reviewed the log of completed QA surveillances and selected a sample of five surveillances for detailed review. In addition, the team reviewed the January 1988 and February 1988 surveillance schedules. From these reviews and discussions with applicable QA personnel, the team verified that selected surveillances covered appropriate areas, were sufficiently technical, and resulted in meaningful findings that were generally adequately reported. The team was informed that many of the surveillances were based on unscheduled reviews of plant functions resulting from QA inspectors' reviews of condition reports, plant logs, other deficiency-related logs, tours, and other plant activities. This policy had been recently implemented to encourage performance-related surveillances that allow inspectors to utilize more of their investigative skills in identifying plant deficiencies.

From review of the selected surveillance reports the team concluded that this policy of unscheduled reviews appeared to have resulted in the performance of effective surveillances.

The team's review of the qualifications of selected surveillance inspectors indicated that the inspectors were well-qualified. The team was informed that several inspectors received plant systems training, which was viewed by the team as an enhancement to the surveillance training program.

2.5.1.2 Quality Control and Engineering

The maintenance and modification quality section was in part responsible for the review of work orders, assignment of QC hold-and-witness points, development of unique inspection plans (when deemed necessary), performance of field inspections, and review of final completed work packages.

The team reviewed the January, February and March 1988 QC work order summary sheets, selected QC inspection reports, and selected work orders. From these reviews, the team concluded that an adequate level of QC hold-and-witness points was being identified and that QC rejections when necessary of in-process work resulted in the generation of detailed QC inspection reports and the performance of reinspections. Final review of completed work packages also appeared to be thorough in that many minor deficiencies were being identified and the work packages were being sent back to the responsible organizations for correction.

The team was concerned, however, that the apparently large final work package review rejection rate indicated that the maintenance and planning organization was depending on the quality organization to find work package deficiencies, rather than performing their own detailed final review. When this concern was discussed with the licensee's QC management, the team was informed that actions were being taken by both the QC and the maintenance organization to improve the quality of the work packages. QC organization actions included providing a

list of identified deficiencies to the maintenance manager, conducting meetings with maintenance management to discuss ways to improve completed work packages, and developing a lower tier document to identify and resolve future deficiencies. The team met with the maintenance manager and was provided an informal plan that was developed to improve the quality of the maintenance organization's work packages. This plan included additional maintenance personnel training and improving material requisition control and final work package reviews prior to sending the completed packages to the quality engineering group.

The team's review of the qualifications of selected quality control and engineer inspectors indicated that the inspectors were well-qualified. The team also interviewed several inspectors and determined that the inspectors were knowledgeable of their duties, had high morale, and had no significant quality control concerns.

2.5.1.3 Summary

In general, the team found the licensee's QA/QC organization to be a significant licensee strength. Findings identified by this organization have and should continue to be a valuable management tool to ensure plant compliance with procedures, Technical Specifications, and other safety and regulatory requirements, and to provide management with identified deficiencies and useful recommendations for plant equipment, personnel and procedural improvements.

Improvements are currently being made to enable the QA/QC organization to better communicate identified problems to plant management and staff. These improvements include: the use of a "split form" that identifies audit recommendations and allows applicable management to communicate with and respond to the auditors concerning these recommendations prior to the audit exit; conduct of preexit meetings with lower level plant supervisors to provide these supervisors with a summary of the auditors' findings and the opportunity to exchange views and pertinent information concerning the findings; and providing maintenance management with specific information concerning work packages that are being rejected because of missing or incomplete information. The team encouraged plant management to continue to take steps to improve the communication channels established with the QA/QC organization to take full advantage of the valuable information provided by this independent group.

2.5.2 Corrective Action Program

Corrective action programs were inspected to determine whether there was a comprehensive and effective means to identify, track, and correct problems. The team reviewed several audit reports that covered the corrective action program, the condition report program, and the licensee's program for detecting emerging trends in condition reports, LERs, and work orders.

2.5.2.1 Audits of the Corrective Action Program

The licensee was in the process of upgrading its corrective action program in response to audit report 87-12, "Effectiveness of Corrective Actions," a maintenance self assessment, an INPO visit, and other reviews. The reviews identified areas that needed improvement, including investigation techniques, troubleshooting techniques, content and retrievability of information contained

in the plant maintenance information tracking system (PPMIS), and the use of the equipment historical data. During a NRC Region III maintenance team inspection, Inspection Report No. 50-440/87025, the maintenance team asked the licensee to provide a presentation on its response to the areas identified above. A copy of this presentation was provided to the OSTI team for review, and from the review the team concluded that the licensee was progressing toward improvements; however, the OSTI team did not conduct a detailed review of the steps taken by the licensee.

The QA audit group was in the process of completing a new audit on effectiveness of corrective actions, and the inspection team asked the audit team leader to brief the team on the results of this audit. He reported that the new audit concentrated on the condition report program and identified, among other things, weaknesses in the way operations personnel interpreted events that should require condition reports. Several examples of plant events were identified in which the auditors felt that a condition report was warranted but not initiated. The auditors were in the process of communicating these findings to the Operations Department at the time of this inspection.

2.5.2.2 Condition Report Program

The team obtained a listing of all condition reports issued in 1988 and selected 13 of 78 for review. From a cursory review of these reports, the team concluded that the licensee's disposition and followup actions appeared to be adequate. During reviews of operations logs the team was sensitive to the audit team's finding concerning operations personnel not always initiating condition reports when required, but identified only one event during the team's two-week inspection that was not properly reported as a condition report when required. This event is discussed in paragraph 2.1.2 of this report.

2.5.2.3 Trending Program

The team reviewed the licensee's 1987 Annual Trend Reports, dated March 11, 1988. These reports included annual trends indicated by LERs and condition reports and summarized the licensee's quarterly trend reports on the same subjects. From the review of the annual trend reports the team concluded that the licensee was adequately categorizing LERs and condition reports and performing detailed evaluations to detect emerging trends. Recommendations identified in these reports appeared to reflect in-depth analyses of the events and provided useful suggestions for programmatic and hardware modifications to help prevent recurrence of similar events.

The team also reviewed the licensee's work order trending program. This program was developed in part to resolve a QA audit finding concerning the requirement to perform trend analysis for work orders (audit PIO 86-48). This trending was accomplished by the reliability and design assurance section (R&DAS). R&DAS reviewed all completed safety-related work orders via the PPMIS computer. Specific information was then transferred manually to the reliability information tracking system (RITS) computer, which had the capability to sort work orders by part numbers or vendors. R&DAS used these data to identify recurring failures of specific components and equipment supplied by specific vendors. The time spent manually transferring applicable data from the PPMIS to the RITS has, however, prevented the staff from performing many detailed analyses of selected components to determine adequacy of periodic

maintenance, design enhancements, or other corrective actions to reduce component problems. Equipment failure information was, however, provided to plant maintenance and engineering personnel for review. To alleviate the resource burden, the licensee was modifying the PPMIS computer software to access data and perform the task the RITS was performing without manual manipulation of the data. Other computer enhancements were being considered that should further improve R&DAS' ability to identify recurring equipment problems.

The team concluded that, when fully implemented, the work package trend evaluation program should provide a valuable indicator of recurring equipment problems. With the implementation of the enhanced systems, R&DAS' resources could be directed towards analyzing data and making significant recommendations for plant improvements.

2.5.2.4 Summary

From the limited review of the licensee's corrective action program, the team concluded that programs are generally in place to identify, track, and correct problems. Problems identified by the licensee's own staff indicate that improvements were needed, and plans for improvement were being implemented. The full implementation of these improvements, coupled with the plant's recent movement from startup to full commercial operation, should result in improvements in plant performance and material condition.

3.0 Exit Meeting

The OSTI team and other NRC representatives met with licensee personnel to discuss the scope and findings of the inspection on March 25, 1988. Attendees at the exit meeting are identified in Attachment A. During the inspection, the team also contacted members of the licensee's staff not identified in Attachment A to discuss issues and ongoing activities.

ATTACHMENT A

ATTENDANCE SHEET

EXIT MEETING - March 25, 1988

NAME	ORGANIZATION	TITLE
J. E. Cummins	NRC/DRIS	Team Leader
C. J. Haughney	NRC/DRIS	Chief, Special Inspection Branch
L. J. Norrholm	NRC/DRIS	Asst. Team Leader (Section Chief)
J. W. McCormick-Barger	NRC/RI	OSTI Team Member
P. I. Castleman	NRC/DRIS	OSTI Team Member
D. R. Beckman	NRC Consultant	OSTI Team Member
R. W. Cooper, II	NRC/RIII	Section Chief
K. A. Connaughton	NRC/RIII	Perry SRI
G. F. O'Dwyer	NRC/RIII	Perry RI
D. P. Igyarto	CEI	Acting Manager, Instrumentation and Controls Section
R. J. Tadych	CEI	Training Manager
B. K. Grimes	NRC/DRIS	Deputy Director, DRIS/NRR
S. C. Guthrie	NRC/RIII	SRI, Big Rock Point, OSTI Team Member
L. R. Miller	NRC	BWR Instructor, Reactor Technology, OSTI Team Member
J. M. Sharkey	NRC/DRIS	OSTI Team Member
R. Stratman	CEI	Acting Gen. Mgr., Perry Plant
S. Tulk	CEI	Supervisor, QA
W. Coleman	CEI	Manager, OQS
G. A. Dunn	CEI	Supervisor, Compliance
T. E. Mahon	CEI	Manager, Site Protection
J. J. Waldron	CEI	Principal Engineer, NSRC Chairman
A. F. Silakoski	CEI	Manager, Reliability and Design Assurance/ISEG

ATTACHMENT A

ATTENDANCE SHEET

EXIT MEETING - March 25, 1988

NAME	ORGANIZATION	TITLE
A. P. Myer	CEI	Supervisor, Independent Safety Engineering Group
S. F. Kensicki	CEI	Technical Superintendant
W. R. Kanda	CEI	Manager, Operation
H. N. Kelly	CEI	Senior Operations Coordinator
E. Buzzelli	CEI	Manager, Licensing & Compliance
F. Stead	CEI	Director, Technical Dept.
A. Kaplan	CEI	Vice President, Nuclear
C. M. Shuster	CEI	Director, Nuclear Eng. Dept.
V. K. Higaki	CEI	Manager, Outage Planning Sec.
D. J. Rossetti	CEI	Ops. Engr., Outage Planning Section (OSTI Interface)
H. Coon	CEI	SVI/Computer Engineer
T. Colburn	NRC/NRR PD-33	Project Manager
K. E. Perkins	NRC/NRR PD-33	Project Director
D. O. Myers	NQAD/MMQS	Sr. Ops. Program Consultant
J. R. Hayes	NQAD/OQS	Quality Engineer
R. A. Newkirk	PPTD/Tech.	Manager, Technical Section
S. J. Wojton	PPTD	Manager, RAD Protection
M. Cohen	PPOD/Maintenance	Manager, Maintenance
M. D. Lyster	CEI/PPOD	General Manager
P. D. Roberts	PPOD-Ops. Section	Lead SVI Coordinator
T. A. Demick	PPTD-Technical Sec.	Operations Engineer
H. L. Hegrat	PPTD-Licensing/ Compliance	Operations Engineer

ATTACHMENT B

LIST OF OBSERVATIONS

440/88200-01, Inadequate Logs, discussed in section 2.1.1

440/88200-02, Failure to Use Procedures, discussed in section 2.1.2

440/88200-03, Lack of Supervising Operator Involvement in Shift Personnel Activities, discussed in section 2.1.3

440/88200-04, Overtime Deviation, discussed in section 2.1.4

GLOSSARY

ALARA	As low as reasonably achievable
ANSI	American National Standards Institute
CFR	Code of Federal Regulations
FSAR	Final Safety Analysis Report
GEI	General Electrical Instruction
HPCS	High-pressure core spray
I&C	Instrumentation and Controls
ISEG	Independent Safety Engineering Group
LCO	Limiting condition for operation
LER	Licensee Event Report
LPCI	Low-pressure coolant injection
M&TE	Measuring and Test Equipment
MOV	Motor-operated valve
MOVATS	Motor-operated valve analysis and testing system
MSIV	Main steam isolation valve
NEDP	Nuclear Engineering Department Procedure
NIS	Not in service
NQAD	Nuclear Quality Assurance Department
NRC	U.S. Nuclear Regulatory Commission
NSRC	Nuclear Safety Review Committee
NSSS	Nuclear steam supply system
OSTI	Operational Safety Team Inspection
PAP	Plant Administrative Procedure
PNPP	Perry Nuclear Plant Procedure
POP	Perry Operations Procedure
PORC	Plant Operations Review Committee
PPO	Power Plant Operator
PPMIS	Perry plant maintenance information system
QA/QC	Quality assurance/quality control
R&DAS	Reliability and Design Assurance Section
RCA	Radiologically controlled area
RHR	Residual heat removal
RITS	Reliability Information Tracking System
SO	Supervising Operator
SS	Shift Supervisor
SVI	Surveillance instructions
TAP	Technical Administrative Procedure
TXI	Temporary Operating Instruction
US	Unit Supervisor
USAR	Updated Safety Analysis Report