INDEPENDENT SAFETY INSPECTION

TEAM REPORT

ON

DRESDEN NUCLEAR POWER STATION

SEPTEMBER 30 - OCTOBER 11, 1996

AND

OCTOBER 28 - NOVEMBER 8, 1996

U.S. Nuclear Regulatory Commission

U.S. NUCLEAR REGULATORY COMMISSION

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Background

Following the June 1987 U.S. Nuclear Regulatory Commission (NRC) Senior Management Meeting, the NRC designated Dresden Station a Category 2 plant. A plant in this category has weaknesses that warrant increased NRC attention until the licensee demonstrates a period of improved performance. Dresden Station was designated a Category 2 plant primarily because of a long history of cyclic performance. In August 1987, the NRC conducted a diagnostic evaluation at Dresden Station to identify the causes of the safety performance problems. The diagnostic evaluation team determined that poor maintenance and testing practices, wear, aging, and the resultant accumulation of equipment deficiencies could cause system and component unreliability. In December 1988, the NRC removed Dresden Station from Category 2 status because the licensee had sufficiently improved safety performance and the physical condition of the plant, and additionally, had committed to complete the Dresden Station improvement program and sustain improved performance.

Plant performance problems appeared again in late 1990. Cyclical performance was identified during the following year, and by January 1992, safety performance at Dresden Station declined to the point that the NRC again designated it as a Category 2 plant. Dresden Station has remained a Category 2 plant since January 1992. More recently, Commonwealth Edison Company (ComEd) commitments to improve performance have been evident in the areas of plant material condition, conduct of operations, and management and organizational changes. However, NRC continued to be concerned about work backlogs, potentially unrecognized equipment problems, and the inability to accomplish work reliably. Because of its long history as a Category 2 plant, NRC decided to conduct an independent safety inspection at Dresden Station to evaluate whether the licensee was steadily and sufficiently improving the overall safety performance of the plant. In particular, this inspection focused on whether the licensee was effective in: (1) correcting deficiencies; (2) conforming to licensing and design basis requirements; (3) conducting maintenance; and (4) operating the plant in a safe and reliable manner.

Operations

Safety performance in plant operations has significantly improved with programs, policies, and staff in place to support continued improvement. Overall, operator performance was a noteworthy strength. Control room operators properly controlled operational activities, such as surveillances, strictly adhered to procedures in most circumstances, and communicated effectively. Operator actions observed were conservative; however, in some instances, operators did not question the basis or completeness of information provided to them by engineers regarding the evaluation of operability issues. A number of equipment problems challenged the operators throughout the inspection. Major challenges remaining in operations included further improvement in the identification and resolution of material condition problems.

Radiation Protection

Overall, the licensee has significantly improved the working environment at the facility with respect to radiation exposure and contamination control, primarily accomplished through source term reduction and effective implementation of the as-low-as-is-reasonably achievable program. As a result, the licensee reduced its staff's overall exposure to radiation and contamination. The licensee had an established plan to further reduce the source term in the future. Despite improvements, licensee staff compliance with plant procedures and Technical Specifications related to the control of high radiation areas and radioactive material remained weak. Ineffective corrective actions in these areas could be attributed to a lack of clear expression of requirements and expectations by licensee managers, as well as a lack of individual worker accountability for adhering to requirements. The team identified multiple examples of radiation protection personnel and radiation workers failing to follow basic radiation protection practices, procedures, and department expectations. While no serious radiological consequences resulted from these deficiencies during this inspection, the potential consequences of repeated failures to survey areas before work were high.

Maintenance and Testing

The licensee recently improved a number of maintenance processes; enhanced the knowledge, skills, and abilities of maintenance personnel; and significantly improved the overall material condition of the plant. However, the effectiveness of these improvements has been reduced by the number of safety- and nonsafety-related emergent work activities. These emergent work activities continued to hamper the licensee's ability to conduct planned work; thereby, adversely affecting the ability to reduce backlogs to the desired level. Several long-standing safety- and nonsafety-related system and component deficiencies have not been corrected, and have resulted in repeated challenges to plant operations.

Testing weaknesses resulted in the failure to detect degraded systems and components. Long-standing programmatic problems with the inservice test (IST) program were not comprehensively addressed from 1987 to 1996. Relief valve setpoints differed significantly, in some cases, from design pressures established for safety-related systems. Opportunities to address the IST program deficiencies, early in 1996, were not promptly recognized and evaluated. The licensee and the team identified additional testing concerns involving the 125 Vdc batteries, the 250 Vdc batteries, and ventilation systems.

Work activities were generally well performed, although rework continued to challenge plant operations. The requalification of workers in fundamental skills was a positive initiative. Some maintenance personnel did not consistently demonstrate an understanding of management expectations or procedural requirements for the conduct of work or identification of maintenance issues.

Engineering and Technical Support

While progress was being made in a number of areas affecting engineering (e.g., addressing configuration management backlogs), and activities reflected increased site management oversight and planning when compared to the past, these efforts were significantly overshadowed by the problems identified during this inspection in the area of design control. The team identified that the licensee was unable to maintain the design basis of the containment cooling service water system under certain conditions, and identified significant weaknesses in the licensee's control of design basis calculations, including a number of errors and nonconservative design assumptions. Some design basis calculations were no longer retrievable, had not existed previously, or were difficult to retrieve. The resolution of some issues was untimely and some commitments were missed. Evaluations of modifications to systems did not always identify system impacts. In some cases, the resolution of issues caused other problems that were not anticipated. These issues reflected (1) the lack of a strong corporate presence in the past to adequately control design basis calculations and the multiple design interfaces, (2) the lack of a challenging and questioning attitude in engineering, and (3) the inability to effectively resolve some long-standing problems.

Management Oversight, Corrective Actions, and Self-Assessment

Corporate oversight and support for Dresden Station were improving, but the changes at the corporate level were less than a year old, and most new initiatives had not been fully implemented. A significant weakness in corporate support to Dresden Station was the failure of the corporate engineering organization to ensure the station's design basis calculations were controlled and maintained.

In the past 2 years, site management oversight was improved and a large number of managers and supervisors with broad nuclear experience were hired. Because of management, supervisory, and process changes, management expectations for the accomplishment of work were not understood in some cases. There was significant progress in addressing the objectives of the 1994 Dresden Plan, although some initiatives were ineffective and implementation of others was delayed. Licensee planning was improving, but plans did not extend beyond 1997.

Site managers and staff were addressing several long-standing obstacles to performance improvement. Management efforts to reinforce individual accountability for safety performance and to improve the capabilities of station personnel, appeared to be effective in addressing these obstacles. The Dresden Station staff was not reluctant to bring safety issues to their manager's attention.

Weaknesses continued in identifying and resolving problems, although problem identification had generally improved in most areas. Licensee self-assessments documented substantive findings in some cases and the effectiveness of the site quality verification organization was improving; however, some licensee self-assessments were weak, particularly in engineering. The actions of the offsite review function, performance monitoring reports, and Plant Operations Review Committee activities served to independently assess performance, although weaknesses in some areas were not identified. Additionally, some corrective actions were ineffective, resulting in repetitive problems. The licensee had recognized weaknesses in root cause analyses and was addressing them. The team also identified weaknesses in implementing the corrective action process.

Root Causes

The team performed root cause analyses for two significant issues involving the failure to resolve long-standing problems and the failure to control and maintain design basis calculations.

- Until the past 12 to 18 months, corporate and site managers were not fully focused on correcting the organizational, programmatic, process, and material condition problems that have been evident for a number of years. As a result, only some of the issues identified in past reviews have been corrected, most notably site management oversight (Sections 6.1.3 and 6.2) and operator performance (Sections 2.1, 2.2, 2.3, 2.4 and 2.5), which was one of the first priorities of the current site vice president. In many instances, corrective actions were still being implemented (Sections 5.5 and 5.6), in others, the corrective actions were not fully effective (Sections 3.4, 3.5, 4.2, 5.2, 5.4 and 6.3.3). In a limited number of areas, particularly engineering (Section 6.5.2), existing performance problems had not yet been recognized or were not fully assessed for significance.

- Corporate management did not provide meaningful oversight of or involvement with their contractor engineering service firms to ensure appropriate design control for design basis calculations. The licensee did not fully appreciate the impact of the growing number of design basis calculations nor the implications of the failure to maintain them (Sections 5.1.1, 5.1.2, and 5.1.3). ComEd eventually institutionalized by procedure the practice of not maintaining design basis calculations, using the experience of the engineers as justification (Section 5.1.7). Acceptance of this practice by corporate managers led to the further degradation of design control and poor quality oversight (Section 6.1.1). In response to previous assessments in this area, the licensee moved the engineering organization to the site in 1994 and increased engineering staffing by hiring a number of contractor engineers, who have worked in the same environment for many years. The transfer of calculations to the site, however, was only completed in 1996, further aggravating the licensee's inability to retrieve design basis information that had not been indexed. Because of the large scope of the engineering initiatives already planned (Section 5.6) and the volume of emergent work (Section 4.2), the restoration of appropriate design control and maintenance of design basis calculations represents a significant challenge to the licensee (Section 5.1.7).

1.0 INTRODUCTION

On September 30 through October 11, and October 28 through November 8, 1996, a special inspection team, that was independent of NRC Region III, from the U.S. Nuclear Regulatory Commission (NRC) assessed the safety performance of Dresden Station, Units 2 and 3. This report describes the results of this inspection at Dresden Station.

1.1 Background

Following the June 1987 NRC Senior Management Meeting, NRC designated Dresden Station a Category 2 plant. A plant in this category has weaknesses that warrant increased NRC attention until the licensee demonstrates a period of improved performance. Dresden Station was designated a Category 2 plant primarily because of a long history of cyclic performance. In August 1987, the NRC conducted a diagnostic evaluation at Dresden Station to identify the causes of the safety performance problems. The diagnostic evaluation team (DET) determined that poor maintenance and testing practices, wear, aging, and the resultant accumulation of equipment deficiencies could cause system and component unreliability. The DET concluded that the root causes of poor performance at Dresden Station were: (1) Dresden Station had not received strong and in-depth corporate attention in the past; (2) an attitude and approach existed that had not been directed at achieving or maintaining a high standard of safety performance; and (3) past improvement initiatives had not been developed in a specific and complete way to overcome deficiencies.

In December 1988, the NRC removed Dresden Station from Category 2 status because: (1) the licensee had sufficiently improved safety performance and improved the physical condition of the plant; and (2) had committed to complete the Dresden Station improvement program and sustain improved performance. However, plant performance problems appeared again in late 1990. Cyclical performance was identified over the next year, and by January 1992, safety performance at Dresden Station again declined to the point that NRC designated Dresden Station as a Category 2 plant. Dresden Station has remained in a Category 2 status since January 1992. More recently, Commonwealth Edison Company (ComEd) commitments to improve performance have been evident in plant material condition, conduct of operations, and management and organizational changes. However, NRC continues to be concerned about work backlogs, potentially unrecognized equipment problems, and the inability to accomplish work reliably.

Because of its long history as a Category 2 plant, and following the June 1996 Senior Management Meeting, NRC decided to conduct a special inspection at Dresden Station to evaluate whether the licensee was sufficiently improving the overall safety performance of the plant. In particular, this inspection would focus on the licensee's effectiveness in correcting deficiencies, conforming to licensing and design basis requirements, conducting maintenance, and operating the plant in a safe and reliable manner. On August 9, 1996, NRC issued a letter to inform ComEd that NRC had established an independent safety inspection (ISI) team to evaluate licensed activities at Dresden Station.

1.2 Inspection Objectives and Scope

The purposes of the ISI were to: (1) evaluate the effectiveness of the corrective action programs; (2) provide an independent assessment of conformance to the design and licensing basis; (3) evaluate the conduct and effectiveness of maintenance activities, including work processes, post-maintenance testing, and maintenance rule (10 CFR 50.65) activities; and (4) provide an independent assessment of operational safety performance.

The ISI team selected for review samples of station procedures, corrective action documents such as action requests (ARs) and Performance Improvement Forms (PIFs), maintenance and testing records, design calculations, design basis documents, licensing basis documents, improvement initiative action plans, self-assessment documents, and audits. The team focused the inspection on the processes for: (1) conducting work in the plant; (2) translating the design basis into procedures, drawings, and instructions; (3) providing oversight of safety-related activities; (4) identifying and resolving problems; and (5) ensuring compliance with NRC requirements.

As part of the ISI, the team reviewed the Dresden Station inspection record to determine whether performance issues in the areas inspected, similar to the findings of the team, had been previously raised to the licensee for correction. The results of this review are included in Sections 2.0 through 6.0 of this report. Additionally, members of the Region III staff provided inspection record background information to the team throughout the course of the inspection.

1.3 Inspection Methodology

The team utilized a modified form of the NRC's Diagnostic Evaluation process to conduct the inspection. The NRC's Diagnostic Evaluation Program is documented in NRC Management Directive 8.7, "NRC Diagnostic Evaluation Program."

The team conducted focused reviews of selected safety systems, including the core spray system, the high pressure coolant injection system, and the 125 Vdc electrical distribution system. To a lesser degree, the team also reviewed portions of the containment cooling service water system, and the 250 Vdc electrical distribution system. The team interviewed more than 100 Dresden Station managers and staff members and interviewed some ComEd corporate officers, including the Chairman of the Board. The information obtained from these interviews was used to validate information obtained by direct observations of licensed activities and document reviews.

1.4 Facility Description

Dresden Station, which includes Units 1, 2, and 3, is located along the Illinois River near the confluence of the Des Plaines and Kankakee Rivers. The site is approximately 50 miles southwest of Chicago and is located in Goose Lake Township, Grundy County, Illinois. Units 2 (License No. DPR-19) and 3 (License No. DRP-25) began commercial operations in 1970 and 1971, respectively. Unit 1 has been shutdown since October 1978.

Units 2 and 3 are both single-cycle forced circulation boiling water reactors (BWRs), each licensed at 2527 megawatts-thermal. The net electrical outputs of Units 2 and 3 are 772 and 773 megawatts-electrical, respectively. The Nuclear Steam Supply System (NSSS) supplier was General Electric Nuclear Division. The units, except for the NSSS systems, were designed by Sargent & Lundy, Engineers. Units 2 and 3 employ the BWR Mark I concept of pressure suppression and have multiple downcomers connecting the reactor drywell to the water-filled pressure suppression chamber, which is also referred to as the suppression pool or torus. The primary containment is a steel-lined, post-tensioned, concrete enclosure, housing the reactor and suppression pool. The secondary containment encloses the primary containment structure.

1.5 System Descriptions

1.5.1 Containment Cooling Service Water System

The containment cooling service water (CCSW) system is an open loop cooling water system consisting of four CCSW pumps and associated valves, piping, controls, and instrumentation. The CCSW system provides cooling water for the low pressure coolant injection (LPCI) heat exchangers and CCSW vault coolers. Additionally, Unit 2 (only) provides cooling water supply to the control room air conditioner chillers. System piping is arranged to form two separate, two pump, flow loops. Each pair of CCSW pumps takes a suction from the crib house via separate supply piping. Two CCSW pumps discharge into a common header that routes the cooling water to the loop's associated LPCI heat exchanger. At the heat exchanger, heat is transferred from the LPCI system to the CCSW system, and subsequently to the river. Appendix A depicts a simplified diagram of the system.

1.5.2 125 Vdc Electrical Distribution System

The safety-related Class 1E 125 Vdc electrical distribution system is the emergency power source for vital loads and certain nonessential service loads. The system provides power to operate solenoid valves, logic trains for the primary containment isolation and emergency core cooling systems, and switchgear circuit breaker control for the 345 Kv, 4 Kv and 480 V electrical busses. The system is configured as an ungrounded system and has devices for the detection and recording of grounds. The system for each unit consists of a 58 cell lead-calcium battery, two battery chargers (one in standby) powered from diesel generator-backed busses and the motor control center distribution system. The battery charger provides power for normal loads and maintains the battery in a state of readiness on float charge. Each battery has a 1408 ampere-hours capacity rating at the 8-hour rate before reaching the minimum discharge voltage of 105 Vdc. Each battery system provides Division I power to its own unit turbine building main bus and unit reactor building bus, and also supplies Division II power to the turbine building reserve bus for the other unit. Appendix A depicts a simplified diagram of the system.

In addition, each unit has an alternate 125 Vdc battery with a dedicated battery charger. The cables from the alternate battery system may be manually connected to the bus to allow the unit battery to undergo discharge testing while both units remain at power.

1.5.3 250 Vdc Electrical Distribution System

The safety-related Class 1E 250 Vdc electrical distribution system is the emergency power source for large vital loads and certain large nonessential service loads. In general, the system provides power to motor loads such as motor-operated valves (MOVs) and pumps (i.e., loads associated with the high pressure coolant injection (HPCI), isolation condenser, and reactor water cleanup systems). The system is configured as an ungrounded system, and has devices for the detection and recording of grounds. The system for each unit consists of a 120-cell lead-calcium battery, one dedicated battery charger powered from a diesel generator-backed bus and the motor control center distribution system. The units share a standby battery charger. The battery charger provides power for normal loads and maintains the battery in a state of readiness on float charge. Each battery has a 1495 ampere-hours capacity rating at the 8-hour rate before reaching the minimum discharge voltage of 210 Vdc. Each battery system provides power to its own unit turbine building motor control center and also supplies power to the reactor building motor control center for the other unit. If necessary, cross-ties between the battery systems can be used and alternate power alignment can be accomplished by installation of movable links. Appendix A depicts a simplified diagram of the system.

1.5.4 Core Spray System

The core spray (CS) system is designed to provide water to cool the core following a loss of coolant accident (LOCA). It provides a spray effect on the core to shower the fuel and limit fuel damage from overheating. Core spray is a relatively low pressure system and its use is limited to certain plant operating conditions. The system consists of two independent spray loops. Each loop is capable of supplying sufficient cooling water to the reactor vessel to cool the core adequately in conjunction with the LPCI system following a design basis LOCA. The two spray loops are physically and electrically separated so that no single design basis event can render both loops inoperable. Each loop includes one alternating current (ac) motor-driven pump, and appropriate valves and piping to route water from the suppression pool to the reactor vessel. The CS pumps for the two loops are powered from separate ac electrical busses, which can receive standby power from the independent emergency diesel generators (DGs), as well as from the normal auxiliary power. Control power for the two CS loops comes from separate direct current (dc) electrical busses. To prevent water hammer, the emergency core cooling system (ECCS) keep fill system is used to maintain the discharge piping full of water. Appendix A depicts a simplified diagram of the system.

1.5.5 High Pressure Coolant Injection System

The HPCI system is designed to ensure adequate core cooling for those LOCA conditions that do not result in rapid depressurization of the reactor pressure vessel (RPV). The HPCI system is also relied upon for safe shutdown for station blackout (SBO) and certain 10 CFR Part 50, Appendix R scenarios. With the exception of the HPCI room cooling fan, the HPCI system is designed to operate without reliance on any ac power sources. The HPCI system includes a steam turbine driving a two-stage, high pressure pump and a gear-driven, single-stage booster pump, valves, piping, and instrumentation. The HPCI system is a single train system. The automatic depressurization system (ADS) is redundant to the

HPCI system. Upon system initiation, the steam from the RPV is directed to the HPCI turbine through a normally closed dc powered MOV. The turbine drives the HPCI pump and the main oil pump. The normal suction for the HPCI system is the condensate storage tank (CST). If the water level is low in the CST or is high in the suppression pool, the HPCI pump suction is realigned to the suppression pool. The water from either suction source is pumped into the RPV through the feedwater sparger. The exhaust steam from the HPCI turbine is discharged to the suppression pool. Appendix A depicts a simplified diagram of the system.

1.6 Station Organization

The Dresden Station is owned by Commonwealth Edison Company (ComEd). Appendix B illustrates the structure for the management of Dresden Station that was in effect during the onsite inspection.

2.0 OPERATIONS

The team reviewed operating conditions and the conduct of operations. This included a review of the areas of operator work performance, immediate operability determinations, procedure adequacy and compliance, training effectiveness, problem identification, and material condition challenges to the plant.

Safety performance in plant operations has significantly improved with programs, policies, and staff in place to support continued improvement. Overall, operator performance was a noteworthy strength. Control room operators properly controlled operational activities, such as surveillances, strictly adhered to procedures in most circumstances, and communicated effectively. Operator actions observed were conservative; however, in some instances, operators did not question the basis or completeness of information provided to them by engineers regarding the evaluation of operability issues. A number of equipment problems challenged the operators throughout the inspection. Major challenges remaining in operations included further improvement in the identification and resolution of material condition problems.

2.1 Operations Worker Performance

During the inspection, the team observed operator performance and evaluated the level of management oversight and direction in the operations area. The licensee stated that continued improvement in human performance was a goal. On the basis of observations and a review of licensee trend data, the team concurred with the licensee's assessment that the operator error rate had declined and that the licensee monitored and developed trends for operator crew errors. The team also concurred with the licensee's assessment that administrative errors were a larger fraction and technical errors a smaller fraction of the error population than in the past.

The operators' conduct of operational activities was always professional. The operators performed proper reviews and turnovers when they left the at-the-controls area of the main control room. The main control room was always quiet and uncluttered and the operators properly controlled plant activities.

The team routinely observed various managers, including senior managers, in the control room discussing issues with the operations staff. The control room staff had more direct interaction with managers than did plant equipment operators. Operations managers exhibited a strong desire to achieve positive changes and to provide an enhanced safety focus for plant operations.

Operations managers established high standards and expectations; however, the operations staff's understanding of these high standards and expectations was inconsistent. The main control room staff demonstrated a clearer understanding of operations standards and expectations than other operations personnel. For example, some plant operators' rounds were not thorough and detailed, which did not meet management expectations. Although the required log information was recorded, many routine checks outlined in the procedure that governs these operator rounds were not completed. Operations managers implemented prompt corrective actions, including reinforcing expectations in shift turnover meetings and revising the operator rounds procedure to clarify expectations.

Throughout the inspection, three-part communication practices during observed control room and plant work activities were consistently employed for providing direction and communicating plant conditions, including communications in the main control room and between the control room and operators in the plant. The operators displayed noteworthy communications during the Unit 3 HPCI system surveillance conducted on October 2, 1996. However, during simulator scenarios observed on November 5, 1996, which emphasized rapid transient and accident conditions, communications and oversight were not as clear and concise as observed during routine operations in the main control room. There were instances in which individuals did not acknowledge or repeat communications. This is further discussed in Section 2.4.

The team observed several routine briefing sessions and determined that the licensee staff conducted the briefings according to the procedure. The briefings provided appropriate information to ensure that oncoming shift personnel were aware of existing and upcoming plant activities. The team observed one instance during a shift turnover briefing that did not meet management expectations. In this briefing, an operator questioned the unit supervisor about a previously observed minor degraded plant condition. The supervisor responded that he was not aware of the repair status and assumed that it was resolved. Licensee personnel present did not challenge this response.

Operations personnel routinely held High Level Awareness Briefings for special or unusual activities and evolutions. The purpose of these meetings was to ensure that they conducted the activity safely and efficiently. The team reviewed Dresden Administrative Procedure (DAP) 07-37, Revision 4, "Conduct of Heightened Level of Awareness Activities," and observed a briefing on October 2, 1996. During the briefing, the operations staff appeared to expect radiological work conditions to change during a Unit 3 HPCI surveillance test because of known reactor steam leaks around the HPCI system control valves. However, they did not discuss continuous radiological protection coverage, and the local operator was not informed that radiological protection entry requirements were likely to change. Changing radiological conditions delayed data gathering during the test.

Control room supervisors provided effective oversight of routine control room activities and surveillances. The unit supervisor promptly involved the shift manager when operability issues arose, such as during a HPCI system surveillance conducted on October 2, 1996. Plant operators demonstrated proper control of plant activities and displayed good techniques for self-checks and peer reviews during control room activities. For example, on October 31, 1996, when a student operator conducted a Unit 3 LPCI system valve operability surveillance, the student operator performed a careful review of the procedural step, followed by the deliberate identification of the switch to be manipulated, and a reverification of the procedural step before manipulating the switch.

However, operators did not always meet operations management standards and expectations for adherence to procedures. For example, on October 22, 1996, plant operators failed to inform the control room staff that they were beginning to fill and vent the Unit 2/3 reactor building closed cooling water heat exchanger. On October 23, 1996, during a Unit 3 HPCI surveillance, control room operators allowed the torus level to increase above the Technical Specification (TS) limit before taking effective corrective action, despite a precursor alarm and a precaution statement in the surveillance procedure. After the forced shutdown of Unit 3 on October 26, 1996, the licensee was using the main steam line drains to control the Unit 3 reactor vessel level. The team questioned two operators who were not able to describe the licensee procedure being used to control reactor vessel level, and one of the two provided an incorrect procedural reference. When questioned, operations managers immediately identified the governing procedure.

2.2 Prompt Operability Determination Evaluations

During the inspection, the team observed the operability determination process and reviewed selected immediate operability determinations. The team also reviewed and discussed the backlog of these evaluations and recent changes to the process. Overall, the team determined that the immediate operability determinations were conservative, with occasional exceptions. For example, the licensee declared the HPCI system inoperable because of concerns with room temperature and oil pump operation even though the test satisfied the acceptance criteria for system flow and response time. The team also determined that the current process was controlled and tracked by the operations department.

However, operations personnel did not always question the engineering basis for some of these prompt evaluations. For example, the operations staff did not challenge the engineering staff's correlation of test results and degraded bus conditions for the standby liquid control system valves. On the basis of additional information that was not initially provided to the operators, the team determined that the licensee's prompt evaluation of, "operable with concerns," was appropriate. In a second instance, engineering's initial evaluation of the control room ventilation system's inability to maintain positive pressure was accepted by operations without validating the basis for engineers' assumptions. The operability determination was subsequently challenged by the Plant Operations Review Committee, which is discussed in further detail in Section 4.6.4.1.

The operability determination process did not begin until an issue was brought to the attention of the operators by the initiation of a performance improvement form (PIF). In several instances, the initial screening of potential operability issues was delayed until a PIF was initiated. The team identified instances in which PIFs were not promptly initiated by engineering department personnel, which is discussed in further detail in Section 5.2.4. Operations department personnel did not appear to be aware of these types of issues or, if they were aware, did not appear to question the delays associated with the initiation of some PIFs.

The licensee substantially revised Procedure DAP 07-31, Revisions 2, 3, and 4, "Operability Determination Evaluations," at the start of the inspection period to add requirements. This revised process required that prompt operability determination evaluations be made within 24 hours unless an exception was approved by operations managers. Four of the thirty-eight immediate operability determinations made during the inspection did not meet this 24-hour goal. For example, the previously described issue involving the control room ventilation system was documented in a PIF on September 26, 1996, but the initial operability screening was not completed until October 2, 1996.

2.3 Adequacy and Compliance With Procedures

The team reviewed operations procedures used in the main control room and in the plant, and concluded that these procedures were capable, as written, of supporting safe operation. Although some procedural errors and codified workarounds existed, as described in Section 2.5, operators demonstrated a clear understanding of management expectations for adhering to procedures as evidenced by appropriate procedural usage in the main control room, the plant, and the simulator. Supervisors reinforced this expectation.

The team observed that many procedures reviewed contained minor errors that would not prevent successful completion of the procedures, such as typographical errors and references to shift positions that were recently changed. Some procedures contained notes that clarified specific steps when the body of the procedure did not refer the user to the notes. Minor labeling inconsistencies existed between the wording of some procedural checklists and installed equipment labels. In particular, the team identified numerous nomenclature inconsistencies associated with the HPCI, CS, and 125 Vdc systems. One inconsistency involving the abnormal procedure for the shedding of 125 Vdc battery loads could have resulted in the wrong load being deengergized or could have delayed implementation while the local equipment operator sought control room confirmation of the breaker to be operated. This inconsistency was not identified during the licensee's recent review of this procedure. Frequently used procedures contained fewer errors than infrequently used procedures.

The team identified that a change to a Unit 1 annunciator procedure was implemented before the alarm setpoint was changed. Annunciator Procedure DAN 923-7 C-1, Revision 6, "U1 Chimney Noble Gas Monitor Failure," which is used by the Units 2 and 3 control room operators, contained an incorrect value for the low count failure alarm setpoint, stating that the annunciator was set to allow 30 minutes before alarming. The annunciator is actually set to allow 10 minutes before alarming. Instrumentation and control personnel encountered problems during the alarm setpoint change activities, and did not change the alarm setpoint as planned. This failure was not communicated to operations personnel to ensure that they did not revise the procedure to reflect the intended setpoint change. The instrument setpoint change and the procedure revision process did not administratively prevent this type of problem. Licensee personnel stated they would review the process to determine whether changes were needed. The licensee revised the alarm procedure with the correct alarm setpoint on October 24, 1996. Failure to maintain an adequate procedure is contrary to 10 CFR Part 50, Appendix B, Criterion V (Deficiency 50-010/96201-01).

The team reviewed and walked down operating Procedures DOP 2300-M1/E1, "Unit 2 High Pressure Coolant Injection System," and DOP 1400-M1/E1, "Core Spray Electrical and Core Spray System," and confirmed that the components and devices observed were in the position required by these procedures. Valves required to be locked by the procedures were locked. Overall, operators had a high level of understanding of basic system operation and design function for the HPCI, CS, and 125 Vdc systems and had a high degree of familiarity with the system lineup described in the procedures.

2.4 Simulator Training

The team observed operator continuing training scenarios during the week of November 4, 1996. During these scenarios, operations managers were actively involved in the training to ensure operations department standards and expectations were met. The training staff clearly understood and continually reinforced these standards and expectations. Operations staff interviewed expressed a high level of satisfaction with the quality and responsiveness of the training staff. However, the performance observed during the rapidly changing plant conditions in each simulator scenario demonstrated weaker communications and directions compared to the routine control room and plant practices observed, particularly for infrequent watch standers.

On November 5, 1996, the team observed licensed operator requalification, peer-observed, training scenarios in the simulator that included four different crew rotations for an operating crew. The scenarios involved an anticipated transient without reactor scram, with complications. For two rotations, the operating crew included some staff members who did not routinely stand control room watches. The team observed one staff crew during one scenario.

During the training week, the operations shift manager was active in identifying deficiencies and areas to be improved. Also, instructors and operations managers established a low threshold for identifying improvement items. During the post-training critique, most observers and crew members identified individual and crew performance problems that occurred during the scenario.

However, while taking into account that the scenarios observed were for training rather than evaluation, operator and crew performance during the rapidly degrading transient and accident conditions in the scenarios was significantly weaker than observed during normal operation in the control room. This was primarily true for crews comprised of staff personnel who were not normally assigned to control room operator positions. The weaknesses the team and the licensee staff observed related primarily to three-way communication breakdowns, simultaneous directions to perform multiple, unprioritized tasks, and individuals failing to provide suggested actions to enhance event mitigation. Additionally, individuals not normally placed in shift supervisory positions had difficulty maintaining the appropriate pace while implementing the emergency procedures. One crew failed to terminate and prevent cold water injection during a simulated anticipated transient without reactor scram, which was required to properly control reactor power during the event.

Operations managers stated that the operators had not been in training for about 11 weeks because of the cancellation of the previous requalification cycle to allow additional resources to prepare for this inspection. They also stated that the length of time between training could have been a factor in the performance observed. Licensee staff noted that the training scenarios observed by the team were repeatedly stopped to allow immediate training feedback on event sequences and procedural requirements, which reduced the validity of the observations compared to real performance or an evaluated scenario. The team observed that uninterrupted crew performance could have been better or worse, depending on the effect of the interruption. The licensee also stated that it had initiated individual performance improvement plans to remediate the performance observed in the scenarios.

2.5 Problem Identification

The team reviewed the operations department's processes and practices with respect to identifying problems. The operations staff performance improved in the area of problem identification as the result of implementing management expectations. However, the team concluded that a number of equipment performance issues had not been properly identified or evaluated by the operations staff.

Plant operators effectively identified material condition problems, such as those discussed in Section 2.6, and human performance errors. However, recognition of some long-standing material deficiencies remained a problem. For example, at the beginning of the inspection, the licensee staff identified the service water strainer backwash controller operating in manual rather than automatic as an operator workaround only after a shad run resulted in a power reduction. The licensee defined an operator workaround as a material or document deficiency that requires an operator to take compensatory or non-standard action to comply with procedures, design requirements or TS. After recognizing that the problem had not been previously identified, operations managers informed the team that a special effort was initiated to identify other automatic controllers positioned in manual because of degraded conditions.

Licensee staff stated that some other plant material condition deficiencies had not been considered and were being added to the operator workaround list. The team also identified other plant conditions that were operator workarounds associated with: single-element reactor vessel level control; Unit 3 HPCI system room cooler condensation; HPCI system auxiliary oil pump operation under certain plant conditions; shutdown cooling pump low suction pressure switch isolation valve; and Unit 3 reactor vessel level control while shutdown using the main steam line drains. In all cases, the licensee staff was aware of these conditions but had not identified them as operator workarounds. Some of the operator actions required to compensate for these material condition deficiencies were incorporated into the licensee's operating procedures. For example, closing the shutdown cooling pump low pressure switch isolation valve required proceduralized local operator actions not otherwise required to start the pump. A number of degraded conditions were not identified as operator workarounds in accordance with the licensee's definition because temporary compensatory measures, which appeared to be permanent in some cases, were proceduralized.

Operations managers stated the operator workaround list was not used to track all items meeting the licensee's definition, but was used to highlight problems meeting this definition for which additional management attention was required to ensure appropriate or timely resolution. At the end of the inspection period, licensee representatives stated that they were revising the definition of operator workaround to better reflect current usage.

In addition, the team identified three unauthorized temporary system alterations that had not been identified or tracked in accordance with the governing procedure. The team identified two of these unauthorized temporary system alterations during general plant tours and the third from a document review. The team concluded that these unauthorized temporary system alterations should have been identified as the result of implementing routine operational activities, such as operator rounds. This issue is discussed in further detail in Section 5.4.

2.6 Material Condition Challenges

A long-standing issue at the facility has been material condition challenges to sustained dual unit operation. The team reviewed the licensee's identification of material condition issues and found a continued high rate of challenges to the operators because of material condition problems.

Some of the self-revealing material condition problems that occurred during the inspection included: (1) a forced outage because of a Unit 3 reactor recirculation pump motor failure; (2) a power reduction in response to a shad run challenging the service water system; (3) system surveillance failures involving the Unit 2 and Unit 3 HPCI systems and Unit 2/3 and Unit 3 DGs; and (4) problems with the control room ventilation system. For example, the shad run partially blocked the service water strainers. The strainer backwash had been previously placed in manual control and local operators were backwashing the system about twice per shift. When the shad run occurred, the strainers clogged much more rapidly than had been expected, reducing service water flow, which was required for a number of normal operating systems in the plant. As a result, the operators reduced reactor power rapidly until the strainers could be backwashed manually.

The team also reviewed the licensee's operability determination log. From September 26 through November 4, 1996, the licensee initiated 38 operability determinations for problems involving a number of systems. Some of the problems identified by the team and the licensee involved: (1) the potential for over-pressurizing the reactor water cleanup system that required operators to remove the system from service and operate without it until the evaluation was completed; (2) the effects of a fire in a Unit 2 motor control center relative to DG 2/3 operability; (3) the adequacy of CS and LPCI system pump net positive suction head; and (4) the adequacy of the HPCI system standby alignment.

Operations personnel interviewed by the team expressed confidence that material condition had improved to support sustained dual unit operations; however, the team concluded that the material condition of the plant continued to challenge sustained dual-unit operation. Section 4.2 provides additional detail of material condition problems that the team evaluated.

2.7 NRC Inspection History

The inspection record documented improved material condition, with continuing weaknesses challenging facility operations. For example, inspection reports in the last year have described problems with 4 Kv breakers, feedwater system valves, and foreign material control. Degraded material conditions caused two unplanned outages at the facility in the 6 months before this inspection.

The inspection record described improved problem identification and ownership but also described nonrecognition of issues and broad trends, and untimely resolution of problems. For example, inspection reports in 1996 identified an unauthorized temporary system alteration involving support plates in the drywell and an unidentified operator workaround involving the use of chart recorder ink pens to physically block feedwater heater control valve switches.

Further, the inspection record detailed continuing procedure quality and adherence weaknesses. For example, in the last year, a HPCI operating procedure was inadequate and system checklist and locked valve procedures were incorrect. The inspection record described the failure to adhere to procedures, causing, for example, an unplanned start of a DG. However, the inspection record also cited good overall procedure quality and use by the operators during a 1996 loss of feedwater event.

Finally, an analysis of the inspection record for 1995 and 1996 revealed improvements in licensed and nonlicensed operator training programs. The 1995 inspection record described weaknesses in TS change training and operating test performance; however, an inspection of the continuing licensed operator training program conducted later in 1995 and 1996 identified no weaknesses.

3.0 RADIATION PROTECTION

The team reviewed radiological conditions of the plant, and the performance of radiation workers and radiation protection technicians. The team inspected high radiation area controls, dosimetry use, posting and labeling, control of radioactive material, as-low-as-is-reasonably achievable (ALARA) program, and staff knowledge and implementation of radiation protection requirements.

Overall, the licensee has significantly improved the working environment at the facility with respect to radiation exposure and contamination control, primarily accomplished through source term reduction and effective implementation of the ALARA program. As a result, the licensee reduced its staff's overall exposure to radiation and contamination. The licensee had an established plan to further reduce the source term. Despite improvements, licensee staff compliance with plant procedures and TS related to the control of high radiation areas and radioactive material remained weak. Ineffective corrective actions in these areas could be attributed to a lack of clear expression of requirements and expectations by licensee managers, as well as a lack of individual worker accountability for adhering to requirements. The team identified multiple examples of radiation protection personnel and radiation workers failing to follow basic radiation protection practices, procedures, and department expectations. While no serious radiological consequences resulted from these deficiencies during this inspection, the potential consequences of repeated failures to survey areas before work were high.

3.1 ALARA Program Implementation

The team reviewed the ALARA program, including station support, exposure goals, and exposure reduction. The ALARA committee was actively involved in exposure goal-setting and monitoring for the station and departments. Major station work groups supported the committee, and although procedures required them to meet quarterly, the committee normally met monthly. The ALARA program significantly contributed to the licensee's reduced total radiation exposure to workers.

The 1996 exposure goal of 440 person-rem was the lowest exposure goal established at Dresden Station. As of November 7, 1996, the station accrued about 376 person-rem. The team reviewed the ALARA exposure estimates for the forced shutdown of Unit 3 and determined that the station had a reasonable plan to remain within the 440 person-rem exposure goal despite this major unplanned work.

The licensee significantly reduced the number of radiological hot spots. Since January 1, 1996, the licensee reduced the number of hot spots from 84 to 42 at the time of the inspection, and planned to reduce this number to approximately 20 by the end of the Unit 3, 1997 refueling outage. Engineering and operations departments were appropriately involved with setting priorities to reduce hot spots.

3.2 Radiation Protection Staff Procedure Adherence

Through direct observation and review of records, the team evaluated the radiation protection staff's adherence to department procedures in areas such as radiological surveys, radiation work permits, postings, and shielding installations. The radiation protection staff failed to follow radiation protection department procedures and regulations on multiple occasions.

The team determined by a review of radiation work permit (RWP) Folder 96-2020, Revision 2, used to perform overnight work in the Unit 2 hotwell, and by discussions with a radiation protection shift supervisor (RPSS), that on three occasions workers entered the Unit 2 hotwell area before determining the current radiological conditions in the work area. The last documented survey at a similar power level was performed on March 3, 1994. Workers were briefed on the radiation levels in the work area using this survey and were briefed on contamination levels in the work area using a radiological survey dated July 24, 1996. These surveys did not record radiological airborne levels in the work area. An airborne survey was not performed by the licensee for this task. The licensee's position was that their historical data indicated that the radiation and contamination levels in the work area have remained constant in the past.

The team concluded that the licensee did not assess the potential radiological hazards present in the work area, the concentration of radioactive material, or the radiation levels at the current power level before the workers entered the work area. Failure to survey the work area and assess the potential radiological hazards were contrary to the requirements of the RWP and 10 CFR 20.1501(a) (Deficiency 50-237(249)/96201-02).

Radiation Work Permit 96-2020 did not specify a stay time for entry into the hotwell area. The failure to specify a maximum stay time on the RWP before beginning the job is contrary to the requirements of TS 6.12.2 (Deficiency 50-237(249)/96201-03).

On October 31, 1996, the team observed workers decontaminating a section of the Unit 3 reactor building overhead and asked to review the survey of this work area. Radiation protection management informed the team that they did not perform a survey before the work activity. The failure to survey the work area and assess the potential radiological hazards was contrary to the requirements of 10 CFR 20.1501(a), and represents an additional example of Deficiency 50-237(249)/96201-02.

On November 6, 1996, the team identified that the entrance way to the radioactive material area surrounding the Unit 1 contaminated demineralized water storage tank was not conspicuously posted as radioactive material. Additionally, an area along the side of the tank had a 2 to 3 ft opening that was not barricaded and a caution sign that was missing the words "radioactive material." The failure to have a conspicuous radioactive material posting is contrary to the requirements of 10 CFR 20.1902(e) (Deficiency 50-010/96201-04).

The team reviewed the process for issuing and inventorying keys to locked high radiation areas (LHRAs). During the review of selected completed checklists, "Daily HRA Key Master Checklist," Form 12-04B, the team identified that 75 LHRA keys listed on page 2 of Form 12-04B were not properly documented as inventoried on September 21, 1996. Section 10 of Procedure DAP 12-04, Revision 23, "Control of Access to High Radiation Areas and Very High Radiation Areas," required high radiation area keys to be inventoried and documented daily. This failure to document an inventory was contrary to the requirements of TS 6.2 (Deficiency 50-237(249)/96201-05).

Overall, the licensee properly maintained the radiation shielding program. However, after review of four temporary shielding packages, the team identified that in all cases documentation was not completed in accordance with Procedure DAP 12-12, Revision 9, "Installation and Control of Temporary Shielding." In several cases, the licensee did not perform pre- or post-shielding surveys, and in one case the licensee did not complete an exposure estimate to install the shielding. This failure to follow Procedure DAP 12-12 was contrary to the requirements of TS 6.2, and represents an additional example of Deficiency 50-237(249)/96201-05.

In addition to the multiple instances of procedural noncompliance, the team identified several instances in which radiation protection technicians and radiation workers either did not understand management expectations or were not implementing them. For example, some first and second level radiation protection supervisors did not understand that the radiation protection manager expected radiation protection personnel, who assumed responsibility for an unsecured LHRA door during the conduct of work activities, to remain at the LHRA door until all workers leave the LHRA. Additionally, the team determined that a number of radiation work permit packages did not contain some of the survey information licensee managers expected.

3.3 Radiation Worker Knowledge and Performance

The team toured work areas and interviewed licensee radiation workers about their responsibilities for work in the radiological posted area (RPA). The team identified that licensee workers interviewed were not aware of the radiological conditions in their work areas and that these work areas were not restored to prework conditions after completing the work.

On October 2 and 3, 1996, the team asked two licensee workers, in the RPA, if they knew the general radiological conditions in their work area. Neither individual knew the radiation levels in the work area. On October 7, 1996, the team asked two different groups of licensee workers what were the general radiological conditions in their work areas. None of these workers were aware of the radiological conditions in their work areas. Section F 9.b.(1) of DAP 12-25, Revision 5, "Radiation Work Permit Program," states that it is the responsibility of all personnel using an RWP to familiarize themselves with the radiological conditions and postings in the work area by reviewing recent surveys or posted survey data. Not knowing the conditions was contrary to the requirements of TS 6.2, and represents an additional example of Deficiency 50-237(249)/96201-05.

On October 8, 1996, the team and a licensee representative toured the Unit 2 torus area, and observed housekeeping material from completed jobs in Bays 1 and 8. Section F.1.f.(8) of DAP 12-25, Revision 5, "Radiation Work Permit Program," states that it is the responsibility of personnel performing a job under an RWP to return the work area to "as found" or better condition after completing a job by cleaning up and arranging for decontamination as necessary. The failure to return the work area to its "as found" condition was contrary to the requirements of TS 6.2, and represents an additional example of Deficiency 50-237(249)/96201-05.

3.4 Recurring Instances of Uncontrolled High Radiation Areas

High radiation area (HRA) control, including the control of LHRA doors and keys, was reviewed to ensure compliance with regulations and station procedures. After reviewing the licensee's past performance history pertaining to HRA control, the team noted that HRA control has been a problem for a number of years. On June 8, 1995, the licensee discovered LHRA accesses to the Unit 2 reactor cavity and dryer separator pit were unlocked and open. On June 15, 1995, the licensee submitted Licensee Event Report (LER) 1-95-001 because a number of Unit 1 HRAs required to be locked in accordance with the requirements in 10 CFR Part 20 were unlocked. On December 11, 1995, the licensee identified that a flashing light used to control access to the Unit 2 reactor water cleanup vault, a posted LHRA, was not functioning. On February 1, 1996, the licensee identified that the Unit 2 drywell LHRA door was unlocked. This problem was documented in NRC Inspection Report 50-237/95-15; 50-249/95-15, dated March 26, 1996.

The team determined after reviewing the PIF summary dated October 3, 1996, that the licensee identified three opened LHRA doors and one additional LHRA problem subsequent to February 1, 1996. On March 15, 1996, the licensee identified unsecured lead blankets covering a drum of sludge in the Unit 1 radwaste yard. On August 30, 1996, the licensee identified that the Unit 1 west reactor equipment drain tank room LHRA was unlocked. On September 18, 1996, licensee staff identified that the LHRA door to the "B" reactor water cleanup heat exchanger room was open. On September 27, 1996, radiation protection personnel discovered that the door to the Unit 2/3 maximum recycle demineralizer LHRA door was unlocked. The failure to maintain these doors or areas locked or controlled is contrary to the requirements of 10 CFR 20.1601 and TS 6.12.2 and represents an additional example of Deficiency 50-237(249)/96201-03. After reviewing the root causes for each problem, the team concluded that the licensee did not implement adequate corrective actions after the February 1, 1996 occurrence.

3.5 Recurring Instances of Uncontrolled Radioactive Materials

In March 1995, in response to a PIF, the licensee performed a "clean sweep" survey for areas outside the RPA and identified approximately 450 uncontrolled, contaminated items outside the RPA. On June 25, 1996, the licensee issued a "Radioactive Material Outside the RPA" effectiveness review report that stated that the completed actions were effective and no additional actions needed to be taken. However, the report also noted that between March 3 and June 14, 1996, the licensee staff discovered approximately 50 additional uncontrolled contaminated items during a second "clean sweep" survey. The licensee identified six additional occurrences before the team's arrival. On October 10, 1996, the licensee identified a seventh item while the team was reviewing the radioactive material release program. The team focused its review on these seven subsequent problems.

The licensee stated that these seven cases were recent problems, and not items missed during the prior "clean sweep" surveys. The most significant example was identified on September 23, 1996, when a stanchion labeled as radioactive material was found in an uncontrolled area of the Unit 2 turbine building. Contamination levels were 60,000 dpm/100cm^2 fixed contamination and 2000 to 5000 dpm/100cm^2 loose contamination. The failure to maintain control of radioactive material is contrary to the requirements of 10 CFR 20.1802 (Deficiency 50-237(249)/96201-06). After reviewing the root causes for each problem, the team concluded that the licensee did not implement adequate corrective actions after the prior occurrences.

In general, the team determined that the licensee properly posted and labeled radioactive material in accordance with regulatory requirements. However, during tours of the RPA, the team identified two bags labeled as radioactive material that did not have the required regulatory information recorded on the label. The first involved a sealed radioactive material bag discovered on September 30, 1996. The second involved a bag discovered on October 7, 1996. Radiological conditions were not recorded or posted; however, the licensee determined that the bags contained contamination levels less than 3000 dpm/100cm^2 and dose rates of less than one millirem per hour. The licensee properly controlled both bags; however, the failure to provide sufficient information, such as, radiation levels, quantity of radioactivity, and date surveyed, is contrary to the requirements of 10 CFR 20.1904 (Deficiency 50-237(249)/96201-07).

3.6 NRC Inspection History

The inspection record documented weaknesses in the control of radioactive material, high radiation area control, and survey programs. For example, the licensee discovered radioactive material outside the RPA a number of times in the recent past. In some cases, surveys needed to evaluate radiological conditions were not performed before workers entered the work area. Additionally, LHRA control problems continued. These examples demonstrated weaknesses in implementing corrective actions. The inspection record also documented that the station had high collective exposure and the source term reduction program produced few results. A continuing reduction in the number of personnel contamination events was also documented.

4.0 MAINTENANCE AND TESTING

The inspection of the maintenance and testing functional area included observations of maintenance and testing activities in the plant, review of work and test packages, and interviews with all levels of maintenance personnel. The team reviewed the effectiveness of maintenance processes, including implementation. The team also reviewed the cumulative effect of component and system work backlogs, as well as the adequacy of testing to verify system operability and conformance with design and licensing basis requirements.

The licensee recently improved a number of maintenance processes; enhanced the knowledge, skills, and abilities of maintenance personnel; and significantly improved the overall material condition of the plant. However, the effectiveness of these improvements has been reduced by the number of safety- and nonsafety-related emergent work activities. These emergent work activities continued to hamper the licensee's ability to conduct planned work; thereby, adversely affecting the ability to reduce backlogs to the desired level. Several long-standing safety- and nonsafety-related system and component deficiencies have not been corrected, and have resulted in repeated challenges to plant operations.

Testing weaknesses resulted in the failure to detect degraded systems and components. Long-standing programmatic problems with the inservice test (IST) program were not comprehensively addressed from 1987 to 1996. Relief valve setpoints differed significantly, in some cases, from design pressures established for safety-related systems. Opportunities to address the IST program deficiencies, early in 1996, were not promptly recognized and evaluated. The licensee and the team identified additional testing concerns involving the 125 Vdc batteries, the 250 Vdc batteries, and ventilation systems.

Work activities were generally well performed, although rework continued to challenge plant operations. The requalification of workers in fundamental skills was a positive initiative. Some maintenance personnel did not consistently demonstrate an understanding of management expectations or procedural requirements for the conduct of work or identification of maintenance issues.

4.1 Maintenance Processes

The team reviewed the implementation of maintenance program processes for work planning and scheduling, preventive and predictive maintenance, and post-maintenance testing. The maintenance rule program was also assessed. Many of these processes had been recently revised and the personnel responsible for implementing them have been in their respective positions for a short period, in several cases for less than one month.

The work planning and scheduling process has not been fully effective, although some improvement in the implementation of the 12-week rolling schedule was observed. Programmatic, personnel, and plant material condition challenges resulted in inconsistent performance of work planning and scheduling. Many emergent work activities, in conjunction with inefficiencies in the work control process, continued to limit the licensee's ability to perform work activities in accordance with established schedules. The preventive maintenance (PM) process was improved by scheduling tasks through the new work schedule process; however, resource and scheduling problems continued to contribute to PM tasks being deferred. The team identified a number of post-maintenance test (PMT) programmatic weaknesses, and the team and the licensee identified some instances of PMTs that were not performed. The licensee established a comprehensive maintenance rule program for Dresden Station, Units 2 and 3; however, the licensee failed to include Unit 1 within the scope of the maintenance rule.

4.1.1 Work Planning and Scheduling

The team identified improvement in the planning and scheduling of work activities while on site. These improvements included the continued integration of preventive and surveillance tasks into the scheduling process and the walkdown of work packages prior to their being released for work in the field. However, the overall implementation of the 12-week rolling schedule was less than fully effective.

During the first 2 weeks that the team was on site, the licensee was operating from a weekly maintenance schedule that involved identifying and developing work activities the week before their scheduled implementation. This schedule was being revised extensively on the basis of emergent work activities during the scheduled implementation week. These delays also caused unnecessary safety-system unavailability. For example, the week before the team arrived on site, delays in completing maintenance involving Valve 3-2301-7, HPCI pump discharge check valve, resulted in the licensee having to declare the Unit 3 CS system inoperable because the critical date for implementing surveillance Procedure DOS 1400-04, "Core Spray Check Valve IST and Piping Flush," had expired. Unit 3 was in cold shutdown during this period.

During the second 2-week period that the team was on site, the licensee improved the implementation of the 12-week rolling schedule by identifying work activities at the beginning of the 12-week schedule and performing work package walkdowns as part of the preparation for the work activity 4 weeks before the activity was scheduled to begin. However, the work planning and scheduling processes were continually challenged by emergent work activities that precluded or delayed the implementation of scheduled work and diverted resources away from meeting the schedule. Notably, four examples involved emergent work activities associated with the control room heating, ventilation and air conditioning (HVAC) system, Unit 2 and 3 HPCI system problems experienced during surveillance testing, DG 2/3 and DG 3 concurrent failures, and the Unit 3 recirculation pump trip resulting in Forced Outage D3F23.

The licensee had taken actions to implement the 12-week rolling schedule earlier in 1996; however, in June 1996, a dual-unit forced outage resulted from safety concerns involving the 4160 V safety-related breakers. These previous efforts were not effective, in part, because of a lack of management attention and the diversion of resources away from the 12-week work scheduling process for the development of the forced outage plan and associated work packages.

The lack of feedback also appeared to have delayed work. Maintenance technicians were not consistently providing feedback to the planners when the work could not be accomplished as outlined in the work instructions or the referenced procedures. For example, during the implementation of an annual PM task on the Unit 3, 125 Vdc battery charger, the electrical maintenance technicians had difficulty gaining access to the internals of the charger panel. The technicians had to stop work to obtain additional guidance. Following resolution of the access problem, the technicians did not provide feedback to the planner to ensure that additional instructions would be included in the work package the next time the PM activity is performed. A second example involved work associated with the replacement of the No. 7 power pack (cylinder) on DG 3. The governing procedure did not provide a minimum clearance for the timing on all the injectors and hydraulic lash adjusters, and a procedural change was not initiated to include the minimum clearance for future use.

4.1.2 Preventive Maintenance

The PM program had not been effectively implemented in the past. Problems included large PM backlogs (overdue), missed PM activities, and PMs that had not been developed or implemented. An effective Vendor Equipment Technical Information Program (VETIP) had not been established to support the development of vendor-recommended PM activities or to ensure that controlled vendor manuals were appropriately maintained (refer to Section 5.6.3). These problems affected both safety- and nonsafety-related equipment.

As of January 8, 1996, approximately 447 predefined activities (e.g., PM tasks and surveillance activities) were overdue. Within 4 months, the backlog was reduced to zero by completing, deleting, or deferring the tasks. The team reviewed approximately 60 of these PM tasks. A number of repetitive tasks were dispositioned by consolidating them into other tasks. Other specific tasks were deferred because of plant conditions, resources, and scheduling problems.

A review of the PM and surveillance tasks from April 30 to November 1, 1996, revealed no overdue tasks. The team subsequently determined that some of the predefined activities that became due during this period were either deleted or deferred. However, several predefined tasks were not deferred in accordance with Procedure DAP 11-02, Revision 26, "Preventive Maintenance and Predefine Program." Specifically, nine (safety and nonsafety) predefined tasks were overdue and no action requests (ARs) were initiated as required by the procedure (Deficiency 50-237(249)/96201-08).

The Performance-Centered Maintenance (PCM) group was established in August 1995 to review PM tasks. The PCM group has reviewed approximately 35 systems to date and had identified repetitive PM tasks, as well as tasks that had not been developed or implemented. However, the review and approval process associated with PCM activities was untimely. For example, the lubrication upgrades for the HPCI system were identified in October 1995 but were still in the review process one year later.

The PCM group extensively utilized the licensee's corporate standard maintenance PM template instead of relying on site-specific data. For example, the oil sampling frequency of the ECCS system keep fill pump was changed from a 6-month interval to an 18-month interval on the basis of a recommended PM frequency template developed by the corporate organization, without considering plant-specific data. Specifically, the current Unit 2 ECCS keep fill pump oil analysis sample indicated possible bearing wear (later identified as slinger ring wear). No documentation was provided that indicated this oil analysis had been dispositioned before extending the sampling frequency. In addition, a PIF was not written when the results of the oil sample exceeded the acceptance criteria as required by Procedure DAP 02-27, "The Integrated Reporting Process" (Deficiency 50-237(249)/96201-09). The licensee's staff was also unable to provide documentation demonstrating that the Unit 2 and 3 oil analysis had been performed semi-annually before increasing the frequency.

The team identified that the CS pump leak off Switch 2(3)-1402-49A was not calibrated and was not included in the scope of any predefined tasks. This switch provides an alarm input to the main control room in the event that high CS pump seal leakage is detected. When this alarm is received the operators are directed, by procedure, to visually inspect the pump seal leak off.

The predictive maintenance program was generally comprehensive for safety-related components, but did not include many balance-of-plant (BOP) components. For example, the Unit 3 circulating water pump, which failed during the inspection, was not included in this program.

4.1.3 Post-Maintenance Testing

The PMT process was described in Procedure DAP 15-10, Revision 4, "Post Maintenance Testing Program." This procedure assigned the primary responsibility for determining PMTs to the work analyst responsible for preparing the work package. The work analysts were required to identify the correct PMT, using either the PMT Matrix (a database in the electronic work control system) or Dresden Station PMT Guideline, WMP-4.0, Attachment 2. Through discussions with the work analysts and their supervisors, the team determined that most analysts had extensive work experience as technicians or supervisors in the area in which they prepared work request (WR) packages. However, most analysts had very limited or no operational experience and no system-specific training.

In October 1996, the licensee established a PMT group to review work requests and assign the appropriate PMT. This group consisted of individuals with extensive operations or plant systems training. Before this group was formed, the on-shift operators reviewed the proposed PMTs, provided by the work analysts, to determine what PMTs had to be performed before declaring a component or system operable.

The team identified that the specific responsibilities, including coordination between the work planners and PMT group, were not well defined. The PMT manager believed that the PMT group was providing a second check of the PMTs identified by the work analysts. The work planning supervisor was unaware that the work analysts were required by Procedure DAP 15-10 to be the primary individuals responsible for identifying the appropriate PMT. The work analysts relied on the PMT group to identify the correct PMT. At the end of the inspection, the licensee was revising Procedure DAP 15-10 to identify the responsibilities of the work analysts and the PMT group.

The PMT Matrix was incomplete and did not identify several components, such as breakers, control switches, and instrumentation and control equipment. The licensee's staff identified that a relatively small percentage of the total station components were within the scope of the PMT Matrix.

The licensee had initiated only a few PIFs for missed PMTs. Two of these PIFs involved the failure to perform PMTs after completing breaker maintenance. PIF 95-4076 was the most significant and involved the lack of a PMT following work on the Unit 3 main field breaker. A comprehensive PMT would have identified the conditions that resulted in the overexcitation of the main generator and the unit auxiliary transformers.

The team identified some WRs that had the incorrect PMT assigned or the PMT was not adequately performed. The licensee replaced a Unit 3 ECCS keep fill pump discharge check valve (WR 950060836-01), but the PMT was performed on another check valve in the system. During the performance of WR 960026808, two Unit 2 scram valve position indication limit switches failed the PMT. These limit switches provided control room indication for the scram valves associated with Hydraulic Control Units 34-47 and 22-03. Although the work package was statused as 54 (failed PMT), the two limit switches were not reworked and the PMTs were not reperformed contrary to the work instructions (Deficiency 50-237(249)/96201-10).

4.1.4 Maintenance Rule

The maintenance rule as described in 10 CFR 50.65, established the requirement to monitor the performance or condition of structures, systems, or components (SSCs) against established goals to provide reasonable assurance that the SSCs are capable of fulfilling their intended functions. On the basis of interviews, the team determined that the site maintenance rule owner (SMRO), and key plant managers and staff had an appropriate knowledge of the maintenance rule and understood their responsibilities.

The licensee's maintenance rule scoping activities were comprehensive and the SSCs that were excluded from the scope were justified. The participation of the expert panel in the scoping process was a strength of the licensee's scoping activities. As a result of this process, the licensee identified that 40 of the 76 systems in the scope of the rule were risk significant.

The licensee determined that Dresden Station, Unit 1, was not subject to the requirements of the maintenance rule because it had a possession only license. The guidance currently provided in NUMARC 93-01, dated May 1993, states in part that "Plants that are defueled with a possession-only license will be governed in accordance with the possession only license." However, the team determined that the current license for Unit 1 is an amended operating license under Section 104 of the Atomic Energy Act, as described in 10 CFR 50.21(b). Therefore, Dresden Station, Unit 1 should have been included within the scope of the maintenance rule. The failure to include Unit 1 SSCs within the scope of the maintenance rule is contrary to the requirements of 10 CFR 50.65 (Deficiency 50-010/96201-11). The licensee subsequently stated that even though they had concluded that the maintenance rule was not applicable, they had a monitoring program for the safe storage of the fuel in Unit 1.

The licensee's two probabilistic risk assessment (PRA) staff members and the SMRO were knowledgeable about the use of PRA, and assisted in establishing an effective process for ensuring that the requirements in the maintenance rule were met. The licensee's expert panel was well qualified to participate in the risk determination process.

The licensee used the On-Line Safety Predictor (OSPRE) computer program that provided a risk achievement worth value for various combinations of systems taken out-of-service. The licensee's lead unit planner and PRA expert used this tool when scheduling monitoring or PM activities. In addition, the licensed plant operators used OSPRE to verify acceptable risk before taking systems out of service. The performance of plant safety assessments before taking equipment out of service met the intent of the maintenance rule.

The team reviewed program documents and records to evaluate the process that was established to set goals and monitor under (a)(1) and (a)(2) of the maintenance rule for the HPCI, circulating water, offgas, 125 Vdc, and CS systems. In general, the goals or performance criteria were in accordance with good safety practices, and industrywide operating experience was taken into consideration when setting goals and performance criteria. However, some of the reliability performance criteria and goals were not consistent with reliability values that were assumed in the PRA. For example, the reliability performance criterion for risk-significant systems was no maintenance preventable functional failures (MPFFs). In essence, this is a reliability of 100 percent, which may not be consistent with the assumptions in the PRA. Similarly, the reliability goal for the circulating water system was no MPFFs. The use of MPFFs as a measure of reliability and its compatibility with the reliability assumptions used in the PRA was the subject of ongoing discussions between the NRC staff and the Nuclear Energy

Institute (NEI) at the time of this inspection. Accordingly, this issue will remain unresolved pending further NRC review (Unresolved Item 50-237(249)/96201-12).

At the time of this inspection, the licensee had completed its scoping of structures and identified 79 functions of structures that should be included within the scope of the maintenance rule. The licensee had also issued a corporate Nuclear Operating Division procedure entitled "Structures Monitoring Program," which provided guidance for monitoring structures in the interim period until NEI 96-03 is issued. In September 1996, the licensee began performing walkdown inspections to document the baseline condition of all structures within the scope of the maintenance rule, which were scheduled to be completed in mid-1997.

4.2 Long-Standing Equipment Problems

The team reviewed long-standing material condition problems involving both safety- and nonsafety-related components and systems. The ability to identify, establish, and implement comprehensive corrective actions to prevent recurrence of operational challenges and problems was evaluated.

The licensee identified a number of long-standing, degraded safety- and nonsafety-related systems and components but had not consistently corrected the degraded conditions. Examples included the HPCI system, instrumentation out-of-tolerance deficiencies, operational problems with the offgas systems, and the repeated failure to maintain safety-related battery room temperatures above the minimum cell temperature design limit. Some Dresden Administrative Technical Requirements (DATR) governed systems have been operated in degraded conditions for extensive periods. In the case of the control room ventilation system (refer to Section 4.6.4.1), degraded conditions resulted in the system being incapable of performing its intended function. The team identified similar concerns for systems that support safety-related equipment or are important to plant operations, such as the control room hot water system and the circulating water system.

4.2.1 High Pressure Coolant Injection System

Historically, Unit 2 and 3 HPCI system material condition problems have resulted in unplanned system unavailability, plant shutdowns, and failed local leak rate tests. These problems included latent material issues that have been identified through inspections, material history reviews, active component failures, and testing activities. The cumulative effect of these problems was evident during the inspection. While the team was on site, both the Unit 2 and 3 HPCI systems were removed from service during testing because of component problems.

The team reviewed the Unit 2 and 3 HPCI system availability for January through November 1996. Repetitive problems with steam trap drain line through-wall leaks resulted in outages for both the Unit 2 and 3 HPCI systems. The team performed an independent determination of HPCI system unavailability, and assessed the Unit 2 HPCI system to be unavailable approximately 5 percent of the time and the Unit 3 HPCI system to be unavailable approximately 1.5 percent of the time.

On October 2, 1996, during the performance of Procedure DOS 2300-3, Revision 36, "High Pressure Coolant Injection System Operability Verification," the control room operators declared the Unit 3 HPCI system inoperable because of an elevated temperature at the HPCI turbine inlet area caused by a control valve leak. This condition contributed to the drainage of excessive condensation from the HPCI room cooler. The licensee identified this leak in 1995 and planned to repair it during the D3R14 refueling outage. Additionally, while placing the HPCI system in standby, the operator noted that the auxiliary oil pump (AOP) did not indicate a red "on" light as expected. The emergency oil pump also failed to start remotely from the control room. Subsequent cycling of the emergency oil pump breaker by the operators cleared the condition, precluding maintenance personnel from identifying the cause of the problem during troubleshooting activities.

On October 23, 1996, the Unit 2 HPCI system was removed from service to replace piping downstream of Valve 2-2301-63B, HPCI drain to condenser isolation valve, which had developed a pin hole leak. Emergent work activity WR 96009387801 for Line 2-2323-1"-LX was initiated because a pin hole leak was spraying steam and water beneath the piping insulation. The leak was located outside the HPCI room by the handrail on the east corner room stairs. The piping was cut out and a new piping assembly was welded in place. There have been approximately 30 similar repairs to this line since 1984. For example, a through-wall leak occurred on this same line on April 26, 1996, at a 90-degree elbow upstream of Valve AO 2 2301-29, HPCI turbine steam supply drain pot to main condenser isolation valve. This leak occurred outside the HPCI system pressure boundary and could not be isolated. In addition, an elbow downstream of Valve 2-2301-65, HPCI turbine stop valve above seat drain isolation valve, was repaired. During the operability run of the HPCI system on October 24, 1996, an excessive steam leak developed in the HPCI room because of inadequate gland seal cooling. Valve AO 2-2301-46, HPCI gland seal cooling pressure control valve, was sticking; thereby, preventing sufficient cooling water to the gland seal condenser. The spring tension on the valve was adjusted, the packing loosened, the stem lubricated, and the operating pressure adjusted to 48 psig.

Extensive maintenance activities have been performed on the Unit 2 and 3 HPCI systems without having corrected the root causes of potentially significant equipment deficiencies. In particular, Valve MO 2-2301-3, HPCI turbine isolation valve, has been leaking past its seat since it was worked during the last Unit 2 refueling outage. Maintenance Request 92005182901 was written in April 1992 to replace the Valve MO 2-2301-3 guides and disk because of leakage past the seat. However, the scope of this activity was reduced when the valve was worked on in June 1996. At the time of the inspection, the valve continued to leak steam, causing excessive steam flow to the condensate drain pots. This contributed to the flow accelerated corrosion problem in the steam line drain system and caused leaking piping elbows in the HPCI pump room, as previously discussed. The licensee has identified similar problems in Unit 3.

The excessive humidity in the Unit 3 HPCI room, which was caused by steam leaks, resulted in the HPCI room cooler exceeding its drain capacity, and resulted in the room cooler depositing large amounts of potentially contaminated water in the room. Therefore, operators had to wear protective clothing and plastic "suits" while performing surveillance tests, which could deter rapid access to the room if required during a plant transient.

Additionally, the licensee identified in 1992 that excessive moisture intrusion was a long-term vulnerability to HPCI system motor-operated valves (MOVs). Valves MO 2(3)-2301-9, HPCI pump discharge isolation valve, and MO 2(3)-2301-10, HPCI discharge isolation valve, were particularly vulnerable because of their location and orientation.

Valves 2(3)-2301-45, HPCI turbine discharge to torus check valves, have failed because of seat damage or insufficient spring tension, resulting in exceeding the 10 CFR Part 50, Appendix J, allowable local leak rate test (LLRT) values. A review of the system maintenance records revealed a history of recurring problems. For example, Valves 2(3)-2301-45 failed several LLRTs in 1994 and 1995. Each time these valves failed, they were repaired or replaced, resulting in the submission of seven licensee event reports over a 9-year period. Other HPCI system valves remain degraded. For example, Valve 2(3)-2301-71, HPCI steam drain valve to torus, failed the last two LLRTs. The team reviewed the material history associated with critical HPCI system MOVs (Valves MO 2(3)-2301-8, -9, -10, and -15), and Valve MO 2(3)-2301-7. During events that occurred in 1989 and 1990, steam voids formed in the HPCI system because of feedwater backleakage through these valves. Although the licensee took extensive corrective action, periodic backleakage recurred.

In January 1989, the licensee initiated Procedure DGA-003, Revision 0, "Loss of 250 Vdc Battery Charger Concurrent with a Design Basis Accident," which identifies the loads that must be shed to ensure that the batteries maintain sufficient capacity in the event both battery chargers are lost and a design basis accident occurs. Step D.1.d. required the operator to, "Trip the High Pressure Coolant Injection (HPCI) AOP within 1.5 hours. If the HPCI system trips or isolates and the AOP breaker has been racked out, the AOP breaker may be racked in to start the HPCI system manually, provided the breaker is racked out when the shaft-driven oil pumps are at full speed."

In the 10 CFR 50.59 safety evaluation (DAP 10-2, Revision 1), dated December 23, 1988, the licensee concluded that the TS and the Updated Final Safety Analysis Report (UFSAR) were not affected by the change. TS 3.5.C.1 requires that the HPCI system be operable whenever reactor pressure is greater that 150 psig and irradiated fuel is in the reactor vessel. UFSAR Section 6.3.2.3.3.1, High Pressure Coolant Injection Automatic Initiation, identifies the auxiliary equipment, such as the auxiliary oil pump, as being required to automatically initiate the HPCI system. Racking out the auxiliary oil pump breaker would defeat any condition in which an automatic restart of the HPCI system is needed. Failure to perform an adequate safety evaluation is contrary to the requirements of 10 CFR 50.59 (Deficiency 50-237(249)/96201-13).

On October 24, 1996, the operations department performed an operability evaluation (OE) as provided by Procedure DAP 02-27. The licensee initially determined that this condition only existed during performance of Procedure DGA-3 and that the HPCI system would remain operable provided that the procedural step to rack in the AOP breaker was implemented.

4.2.2 Nonsafety-Related and DATR System Backlogs

The team reviewed the corrective work backlogs for the Unit 2 and Unit 3 systems, reviewing those systems with the most extensive backlogs or that contributed appreciably to the number of emergent work activities. Extensive corrective work backlogs were associated with the HVAC, offgas, and fire protection systems. Two examples involving control room and east turbine building ventilation system operability concerns are discussed in detail in Section 4.6.4. The overall material condition of these systems has been poor for an appreciable period. Since early 1996, the licensee has attempted to resolve these long-standing problems by initiating actions to reduce the fire protection system backlog. Current backlog reduction efforts for the ventilation and offgas systems were initiated because of system functionality concerns and continued operational challenges.

The Units 2 and 3 offgas systems have been degraded for extended periods. Numerous operational problems have occurred, including difficulties in placing the Unit 3 offgas system into service during the September 1996 plant startup. A 1995 fire in the Unit 3A charcoal bed rendered the train unavailable except for emergency use. Previous modifications to correct operational problems were limited in scope and not effectively implemented. For example, the Unit 2B steam jet air ejectors (SJAEs) were modified to preclude operation of the offgas system with unrecombined or undiluted offgas at or near atmospheric pressure to prevent fires and offgas system explosions. Because this modification was not adequately implemented, the system has not operated effectively. In addition, the modification to Unit 3 has not been implemented. Other operational problems have included high moisture in the system requiring the charcoal beds to be bypassed, inadequately sized drain lines, and long-standing problems with the absorber vault temperature controls.

The licensee was addressing the outage and nonoutage fire protection system backlog. As of October 21, 1996, the nonoutage corrective work backlog was 108 items, and 44 of these items were identified before January 1996. To reduce this long-standing backlog, the licensee corrected the isolation problems between the Unit 1 and Units 2 and 3 header, which prevented operations from taking the system out-of-service for maintenance.

4.2.3 Corrective Actions for Material Condition Deficiencies

The team reviewed the implemented actions to correct component and system deficiencies that have affected safety-system operability or plant operations. The team concluded that potentially significant material deficiencies were not (1) consistently identified, (2) evaluated for root causes, and (3) promptly corrected.

4.2.3.1 Numerous Instrumentation Out-of-Tolerance Problems

The team reviewed performance improvement forms (PIFs) for the CS, HPCI, and 125 Vdc systems that were initiated from 1993 to present, identifying numerous PIFs pertaining to instrument out-of-tolerance deficiencies. In 1996, more than 30 instrument out-of-tolerance deficiencies were associated with the CS system. In August 1996, PIF 227A-12-1996-08461 was initiated because the Unit 3 CS Master Trip Unit (MTU)-3-1471-B could not be calibrated, resulting in the CS system being declared inoperable. A number of other instrumentation deficiencies that were identified before 1996 also resulted in safety-related systems being declared inoperable.

Before establishing the instrument trending group in 1996, instrumentation failures were corrected by calibrating or replacing the instrument, and the licensee had not identified that groups of instruments were routinely drifting out of calibration. Although PIFs were being written for the instruments that were out of calibration, no trending of the failures was performed, until September 1996, when the site quality verification (SQV) department began trending the instrument out-of-tolerance problems. On the basis of this information, the licensee's staff began to monitor these instrument out-of-tolerance deficiencies. The cognizant engineer assumed responsibility for addressing instrument out-of-tolerance problems, approximately 2 months before this inspection.

In mid-July 1996, the SQV department initiated Corrective Action Record (CAR) 12-96-061, and requested plant engineering to provide a response and corrective measures regarding expectations and goals for instrument out-of-tolerance problems. The response and corrective actions were in the process of being developed during this inspection but had not been completed. Discussions with the responsible system engineer revealed that a list of top instrument issues affecting 11 systems was developed as part of the corrective actions. The automatic depressurization system was the first system addressed; however, the corrective actions proposed for CAR 12-96-061 were not timely in addressing the instrument out-of-tolerance problems for the remaining 10 systems.

4.2.3.2 Recurring Safety-Related Battery Room Low Temperature Events

The team identified two events that challenged the operability of the Unit 2, 125 Vdc batteries. Both of these events involved low battery room temperature conditions during the winter months, and revealed a design weakness in the Unit 2, 125 Vdc battery room heating system. Although the licensee had written a PIF for the first of these two events, which occurred on January 19, 1996, no PIF was written for the second event, which occurred on February 3, 1996. The licensee took no corrective actions as a result of the first event to prevent recurrence.

On January 19, 1996, a high voltage operator (HVO) discovered that the Unit 2, 125 Vdc battery room temperature was 64°F and falling. The minimum allowable room temperature on the HVO tour sheet was 68°F to prevent the battery electrolyte temperature from falling below its design temperature limit of 65°F. The purpose of maintaining battery electrolyte temperature above 65°F is to ensure that the battery is capable of delivering the required current. The battery room temperature decreased because the east turbine room ventilation system (ETRVS) dampers had fully opened allowing cold outside air (10°F) to come into the east turbine room building through the ventilation system. This system supplied ventilation to the Unit 2, 125 Vdc and 250 Vdc battery rooms and the auxiliary electric (AE) room. Supplemental heating was provided to the Unit 2, 250 Vdc battery room through the in-line HVAC steam converter. However, because the Unit 2, 125 Vdc battery room was not designed with its own heating and cooling system, a sudden inrush of cold air into the battery room caused the room temperature to decrease rapidly. The team identified that the ventilation dampers were wired shut to prevent a further decrease in the battery room temperature. The licensee failed to authorize a temporary system alteration to wire shut the dampers, which is discussed in further detail in Section 5.4. The licensee could not demonstrate that the battery electrolyte temperature remained above 65°F.

Although the licensee initiated PIF 96-5468 to identify this adverse condition, no corrective actions were taken to prevent recurrence of this event. Consequently, on February 3, 1996, when the ETRVS dampers were fully opened, the Unit 2, 125 Vdc battery room experienced another temperature transient. However, this time the room temperature decreased even more rapidly because the outside air temperature was -20°F. The team determined that the battery room temperature was 56°F before the system engineer was able to wire the damper shut. Temporary System Alteration 2-06-96, which authorized the engineers to wire the dampers shut, was completed after the temporary system alteration was performed on the dampers. The licensee did not write a PIF to document this event. The failure to initiate a PIF is contrary to the requirements of Procedure DAP 02-27, and constitutes an additional example of Deficiency 50-237(249)/96201-09. Also, the licensee could not demonstrate that the battery electrolyte temperature measurements were taken to ensure that electrolyte temperature remained above the design temperature limit of 65°F.

The team identified that the ETRVS dampers were fully opened to provide alternate ventilation to the AE room. Because of overheating concerns for equipment in the AE room, alternate ventilation was aligned for operation when the normal ventilation lineup was secured as the result of work on a motor control center. By design, the alternate ventilation lineup caused the ETRVS dampers to completely open to provide maximum cooling to the AE room. Although the alternate ventilation lineup had the desired effect of maintaining proper ventilation in the AE room, it also resulted in overcooling of areas such as the Unit 2, 125 Vdc battery room.

Heating to the Unit 2, 125 Vdc and 250 Vdc battery rooms is provided by the plant heating boiler and the HVAC steam converter (control room hot water heat exchanger), both of which are BOP systems that have operated unreliably. At the end of the inspection, the control room hot water system was unavailable and had been out of service since May 1996 for corrective maintenance. Because of problems with the steam converter, and problems with ETRVS heating, temporary heaters were used to maintain the Unit 2, 125 Vdc and 250 Vdc room temperature above 65°F.

The team concluded that the long-term heating problems with the safety-related battery rooms had not been adequately addressed. As a result of past battery room temperature problems, the battery system engineer initiated Engineering Request (ER) 9500259 to add steps to the operations department winterization procedure to adjust the east turbine room area dampers in order to maintain battery room temperature during the winter months. Also, on March 28, 1995, the battery system engineer initiated ER 9500288 to install Unit 2, 125 Vdc battery room duct heaters. The ventilation system engineer rejected ER 9500259 on March 4, 1996, with no explanation given. ER 9500288 was rejected on

May 28, 1996, on the basis that there were no problems with the operators maintaining battery room temperature during the winters of 1995 and 1996 and the operators were able to manually position the intake damper to maintain battery room temperature above the battery cell design basis temperature.

The team determined that the basis for rejecting ER 9500288 was invalid because the January 19 and February 3, 1996, events challenged the operability of the Unit 2, 125 Vdc battery. The failure to implement corrective actions to prevent the recurrence of significant conditions adverse to quality is contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" (Deficiency 50-237(249)/96201-14). The team also determined that the plant had experienced similar problems maintaining minimum battery room temperature for nonsafety-related batteries in the plant.

4.2.3.3 Recurring Condenser Recirculation Flow Valve Problems

On October 6, 1996, the team observed aspects of Work Request (WR) 960093646 for the Unit 2 condenser inlet Valve MO 2-4402D, condenser flow reversing valve. During operation of the valve to reverse cooling water flow through the hotwell, the breaker associated with the valve's MOV actuator tripped on thermal overload. The licensee subsequently identified that the pinion gear, although appropriately staked, had travelled down the motor shaft causing the gears to bind. Previous maintenance activities were not appropriately implemented to prevent this latest MOV failure.

In March 1993 (WR 910053319), the MOV actuator was rebuilt; however, the associated HBC (90 degree gear box unit) could not be removed because of rusted bolts. As a result, no work was performed. An AR was not initiated to identify the need to perform preventive maintenance on the HBC unit. In October 1993, the licensee identified that the motor was drawing excessively high amperes (amps or A). The limit switches were adjusted and the MOV signature was evaluated as acceptable.

In October 1994, the MOV continued to draw excessive current. Licensee personnel installed a gasket on the gear cover in order to improve the alignment of the gear mating surfaces. This action was not successful in reducing the MOV current draw. No further action was taken until the valve failed in October 1996. The licensee has not conclusively determined the cause for the MOV problems; however, the lack of preventive maintenance on the HBC was suspected of being the cause of the MOV binding, which resulted in the excessive current draw.

4.3 Implementation of Management Expectations

The team determined that maintenance department expectations were well understood by the managers and maintenance supervisory personnel. Discussions with craft personnel indicated an overall understanding of management expectations, although the implementation of these expectations was inconsistent. There were several instances in which expectations and procedural requirements were not met during the conduct of maintenance activities.

Although the licensee disseminated the Dresden Station Maintenance Standards and Generating Stations Safety Rule Book, problems continued to occur in the areas of the safe use of tools and protective clothing (e.g., insulated tools and face shields), radiological work practices, and the use of administrative tools, such as the lifted leads log. Feedback of problems identified during the implementation of work activities was not always given to planners.

Other problems identified included the safe storage of equipment in the plant. Although Procedure DAP 07-48, Revision 1, "Control of Lay Down, Storage Areas, and Equipment In Use," required that ladders be secured following their use, the team identified four examples in which ladders were not properly secured, including: (1) a ladder on the 544 ft-elevation of the radwaste building; (2) a ladder in the Unit 3 turbine building, 517 ft-elevation; (3) a ladder in the reactor feed pump room; and (4) a ladder in the Unit 2 control rod drive west bank accumulators (Deficiency 50-237(249)/96201-15).

4.4 Overall Plant Material Condition

The general material condition of the plant has been improved significantly. The Units 2 and 3 LPCI, CS, Unit 2 DG, and reactor feed pump rooms and equipment appeared to be in good condition. A number of areas in the plant were recently decontaminated and painted. Relatively few valve leaks were observed by the team during tours of the facility. However, the level of general material condition and cleanliness of some areas of the plant was not as high as in other areas. For example, there was seepage through the walls and behind wall plates in the condensate demineralizer room. The condensate booster pumps leaked, and both hotwell sample pumps were not functional. The sample pumps had not worked for an extensive period and appeared to have been abandoned in place. The licensee identified additional components that appeared to have been abandoned in place without being properly dispositioned. The team identified a number of other minor material condition deficiencies, such as temporary tags hung on equipment and instrumentation since 1991. These items were given to the licensee for evaluation.

During other walkdowns, the team identified that maintenance personnel had routed a water hose over safety-related Busses 23-1 and 24-1. The work activity was immediately stopped by the licensee and the hoses rerouted. Operators had not identified the potential risk to the busses in the event of a hose rupture or leak.

4.5 Work Performance

The team observed the conduct of maintenance work and surveillance activities, and assessed the identification and causes for rework and repeat work, noting delays in the performance of work activities in a number of cases.

4.5.1 Observation and Evaluation of Work Activities

The team observed a number of maintenance and testing activities during the inspection, finding appreciable delays in the implementation of several of the work activities. These delays were caused by emergent work activities, operations personnel not being available to hang out-of-service tags (administrative controls to isolate equipment), and a lack of available parts. In one case, work package instructions were not adequate to gain access to the component.

The work performed under these activities was professional and thorough. Technicians were experienced and generally knowledgeable of their assigned tasks. In some cases, the team observed supervisors, component engineers, and system engineers monitoring job progress. For example, the team observed in the first week of November that the 2B pump back compressor work was well coordinated between operations, maintenance and the cognizant component engineer, and the work was appropriately implemented by the maintenance craft.

4.5.2 Review of Completed Work

The team reviewed a number of completed work packages to determine whether: (1) the work instructions were appropriate to the circumstances; (2) PMTs were performed; (3) the description of work performed was adequately documented; (4) the as-found conditions would support root cause investigation, if necessary; and (5) all the acceptance criteria were met. The team identified several instances in which maintenance personnel did not initiate PIFs as required.

- The Unit 3 ECCS keep fill pump discharge check valve failed open during post-maintenance testing. No PIF was written indicating the valve failed its PMT. The valve was replaced.

- The Unit 3 ECCS keep fill pump was leaking water from the bottom of the pump casing. The WR documented that the minimum flow orifice was installed backwards. No PIF was initiated for the minimum flow orifice being installed backwards. Work was completed on May 24, 1995; however, the PMT was performed approximately 8 months later on January 28, 1996. Discussions with licensee personnel indicated that the system was not declared inoperable because the backup system (condensate storage tank) was aligned with the CS system during maintenance of the keep fill pump. It appeared that the pump was returned to service prior to performing a PMT. The licensee subsequently informed the team that the PMT was completed on May 25, 1995; however, input into the electronic work control system indicated a date of January 28, 1996.

- Work Request 96009693601,which was implemented to replace power pack Number 7 on DG 3, did not identify the as-found condition. A coolant supply line connection was tightened on power pack Number 10 and documented under minor maintenance/adjustments without documenting the measuring and test equipment (M&TE) used. The loose coolant line resulted in approximately 13 gallons of water in the DG 3 oil box. A PIF was not initiated to document this condition. The coolant lines to the other power packs were checked using a torque wrench; however, the work performed was not documented.

The failures to initiate PIFs for these instances is contrary to the requirements of Procedure DAP 02-27, and constitute additional examples of Deficiency 50-237(249)/96201-09.

On October 15, 1996, Relay 127 VF/HGA located in the DG 2/3 auxiliary cabinet, short circuited and resulted in the failure (burning up) of the control transformer that fed the circuit located in motor control center (MCC) 28-1, Cubicle G3. Since the control circuit did not have any short-circuit protection, the short-circuit current flowed through the circuit until the windings of the control transformer interrupted the fault. As a result of the heat generated by the burning of the HGA relay, the outer insulation of wiring located nearby burned and charred. The licensee's preliminary failure analysis report indicated that intensive heat was generated as disclosed by carbonization of insulating material on the transformer windings, melting of the winding wire (which required temperatures above 1083°C, the melting point of copper), and melted phenol on the auxiliary contacts.

There were a number of problems in the performance of the corrective action for the repair of the MCC cubicle. The accepted value of the closed contact resistance for the power relay was 10 K-Ohms, contrary to the work procedure requirements of 20 K-Ohms. The determination of the extent of damage caused by the short circuit was made on the basis of a visual inspection only, which would not detect potential long-term damage of insulation caused by the thermal effects of the prolonged flow of the short-circuit current. The maintenance verification indicated that "No post-maintenance verification specified," which was not in agreement with page 5 of the work procedure (DES 7300-05). The accepted value of closed contact resistance for the control relay was 1 Ohm. This was not consistent with the value of 0.01 Ohm utilized in Calculation 8982-19, which evaluated the minimum acceptable voltage. The report did not provide any information related to the extent of the damage in the relay cabinet, which was necessary to determine whether repairs were successful in correcting the damaged equipment. The troubleshooting to determine the voltage to ground indicated that the acceptable circuit voltage to ground was zero. Because of the presence of capacitance to ground, the voltage of the system to ground should have been about 60 V if measured with a sufficiently high internal resistance voltmeter. The licensee initiated actions to evaluate and correct the work package.

The repairs were not performed in accordance with the work instructions, and constitutes an additional example of Deficiency 50-237(249)/96201-10. Similar transformer burnouts had occurred in the past, and the associated 120 Vac control circuits did not have short circuit protection provided by fuses (refer to Section 5.1.4.4).

4.5.3 Rework Activities

Since June 1995, the licensee identified 420 rework and repeat items. Of these, 190 were identified in 1996. The majority of these items were attributed to mechanical maintenance. The rework issues included improperly installed check valves and instrument lines, leaking flanges and valves, and incorrectly installed wiring.

The team identified apparent rework issues that were not documented in PIFs, and followed up other rework concerns identified by the licensee. These issues included multiple rework activities associated with Instrument Air Compressor 2A, Recombiner Exhaust Fan 2B (no PIF initiated), Unit 2 ECCS keep fill pump (no PIF initiated), Unit 2 scram valve position indication (no PIF initiated), and the pump back compressors. The team also identified that rework concerns involving the continuous air monitors were not being identified and tracked as rework. Additionally, the maintenance department's July 1996 self-assessment identified that some rework issues were not being reported because some maintenance personnel believed that they would be disciplined for identifying rework.

Instrument Air Compressor 2A rework issues continually challenged the operations and maintenance departments. System outages and a modification to the Instrument Air Compressor 2B were delayed because of multiple rework activities. Poor work practices, including a failure to utilize match marks, resulted in check valves being improperly installed in the 2A instrument air dryers. Foreign material in the air control lines prevented proper operation of the air operated solenoid valve, and two incorrectly landed leads prevented the air compressor from loading.

Recombiner Exhaust Fan 2B was worked in October 1995 because a loud noise occurred during operation. This fan subsequently failed the PMT and was reworked in January 1996. Again it failed the PMT and was reworked in February 1996.

The licensee stated that the overall number of rework activities decreased since June 1995 because of additional management attention in this area. The number of rework issues attributed to a lack of basic maintenance skills, particularly involving mechanical connections such as flanges, has decreased. The licensee perceived the decreased rework to be an indication of the effectiveness of the recent Phase 1 training provided to mechanical maintenance workers.

4.5.4 Maintenance Training

The licensee assessed work-related skills in early 1996. The resulting requalification of craft workers to strengthen confidence in their fundamental skills was a positive initiative. Phase 2 training and specialized training in Phase 3 were designed to prepare the craft workers to perform tasks previously assigned to specialist contract workers. Current training upgrade activities included updating analyses for the job assignment matrix (JAM) to better define the underlying skills associated with key jobs. The progress in revising the JAM varied among the three maintenance work groups. Electrical maintenance, although working toward the same goal of revising the JAM, has not made as much progress as mechanical and instrumentation maintenance. However, all departments have scheduled training throughout 1997, which was developed on the basis of the information that will appear in the revised JAMs. The goal was to have each maintenance worker attend approximately 160 hours of training in 1997. The approach to improve the overall skill level appeared to be well planned and was being executed in accordance with these plans. Self-assessments of technical training programs were conducted during 1996, with the most recent dated October 1996. Regular program assessments were expected to continue under the scope of Procedure DAP 02-38, "Station Self Assessment Program."

4.6 Testing to Ensure Conformance with Design and Licensing Bases Requirements

The team reviewed elements of the IST and 10 CFR Part 50, Appendix J programs for the resolution of previous programmatic and implementation weaknesses, and reviewed testing associated with the safety-related station batteries and ventilation systems. Some long-standing IST program and implementation problems had not been corrected. The design basis documents (DBDs) did not support the IST program. The licensee identified that ECCS relief valve settings were not adequate and resulted in relief valve setpoints that exceeded ECCS design limits. Testing activities for the safety-related batteries and ventilation systems did not consistently conform with the design and licensing basis requirements. Incomplete control room modifications, in addition to inadequate testing, resulted in the control room ventilation system being maintained outside the design basis. The east turbine building ventilation system had similar problems.

4.6.1 ECCS Relief Valve Setpoints

The DBD-specified setpoint for Valve RV 2-2301-23, HPCI pump suction relief valve, was 100 psi. Maintenance Procedure DMS-0040-1, Revision 4, "Relief Valve Refuel Outage Surveillance/Testing," required the setpoint to be set at 150 psi. Work Request RD20345, dated May 1994, described that Valve RV 2-2301-23 was leaking at 10-20 psi. The relief valve failure was evaluated as required by Section XI of the ASME Code; however, the evaluation did not consider: (1) that fission products from torus water could have leaked through the relief valve to the radioactive waste system; or (2) whether the HPCI pump would have sufficient net positive suction head (NPSH) to operate properly.

During an integrated leak test (ILRT), the licensee identified that torus water was leaking from the cap of Valve 2-1599-13D, LPCI pump suction relief valve, into the LPCI room at 2.5 gpm. This event occurred on February 28, 1996, but PIF 237-200-96-18200 was not written until September 18, 1996. The root cause analysis cited additional examples of relief valve protection exceeding the design pressure rating of the piping, including the LPCI pump suction and discharge piping, the LPCI heat exchanger shell side and tube side protection, the HPCI pump suction piping, and the CS discharge piping. The actual relief valve setpoints were found to be set above the piping design pressure specifications given in Sargent & Lundy piping installation requirements, Specification K-4080.

The specified design pressures for the CS discharge piping was 350 psig and the LPCI suction piping was 65 psig, respectively. The relief protection for the CS discharge and LPCI suction piping was set at 500 psig and 150 psig, respectively. All relief valves were previously set and tested using Procedure DMS 0040-01, "Relief Valve Maintenance," and were in this condition since initial plant startup. The values established in the procedure were related to purchasing specifications and not to design requirements. The licensee stated that relief valve setpoints for the CS pump discharge and the LPCI pump suction cannot be lowered to the specified design operating pressure because the normal system operating pressure often exceeded the specified design pressure.

The licensee performed an engineering evaluation and determined that all ECCS systems were operable, although the LPCI pump suction and the CS pump discharge piping may not be within the design limits. The root cause analysis also provided immediate and long-term corrective actions, including immediate operability determinations, a complete review of the relief valve program, and sampling of code pressure vessel relief protection, safety-related component relief protection, and relief protection for ASME Code B 31-1 components.

The team determined that the licensee's DBD, Sargent & Lundy Specification K-4080, and Procedure DMS 0040-01 did not contain accurate or consistent design information for design pressures and relief valve setpoints. The adequacy of ECCS relief valve setpoints and Valve RV 2-2301-23 will remain unresolved pending further review by NRC (Unresolved Item 50-237(249)/96201-16).

4.6.2 Inservice Testing Program

The team reviewed corrective actions to resolve the long-standing IST program and implementation problems. The licensee failed to address some of the IST program deficiencies that were identified in the NRC's 1987 diagnostic evaluation (DE) and the licensee's 1988 annual stated goals.

4.6.2.1 Valve Testing Deficiencies

The team identified several discrepancies among actual stroke times, the DBD-specified maximum stroke times, and ASME Code, Section XI-required action range stroke times for several HPCI and CS system valves. For example, the actual stroke times for Valve 2-2301-14, HPCI gland seal supply valve, was 12 seconds to open and 11 seconds to close. This exceeded the DBD-specified value of 10 seconds to both open and close. Similar observations were made for the CS system valves. The DBD and the General Electric Specification listed CS injection valve stroke times as 10 seconds. The actual recorded stroke times for the CS injection valves were 14.5 seconds and greater. Additionally, the DBD-specified a stroke time of 20 seconds for Valves MO 2(3)-2301-3 and -8, and Valve MO 2-2301-9. The IST-required action range for these valves exceeded 20 seconds. As a result, the DBD maximum stroke time would be exceeded before corrective action would be taken. The licensee stated that a PIF was written and the corrective action would be taken to revise the DBDs.

Valve 2(3)-2301-20, HPCI pump suction check valve isolation, is located on the HPCI pump suction portion of piping from the condensate storage tank (CST) and suppression pool (torus) and serves as backflow protection for the section of piping routed from the CST. Valves 2(3)-2301-20 were designed to isolate the CST from the torus in the event that Valves MO 2(3)-2301-35 and MO 2(3)-2301-36, HPCI pump suction torus isolation valves, are opened. During a postulated accident, when the suction for the HPCI pump is realigned to the suppression pool, this check valve functions as an ECCS system pressure boundary valve outside of containment. In the event of a failure of Valve MO 2(3)-2301-6, HPCI pump suction CST isolation, to close, Valve 2(3)-2301-20 will be the only pressure boundary.

The HPCI DBD described Valve 2(3)-2301-20 as a secondary containment boundary valve. This valve had not been leak tested or closure tested, and the last time it was verified to function, by valve disassembly, was on September 23, 1991, for Unit 3 and on February 3, 1993, for Unit 2. The specified frequency for the inspection was once every 8 years.

The NRC's 1987 DE of Dresden Station identified Valve MO 2(3)-2301-20 as being within the scope of the IST program but had not been tested. Although the licensee implemented corrective actions for other IST valve deficiencies identified by the NRC's 1987 DE, Valve 2(3)-2301-20 was not included within the scope of the IST program for testing. In September 1996, the licensee's system review process also questioned whether closure testing was appropriate for this valve.

On the basis of the team's questions and the licensee's review of the IST testing bases for this check valve, the licensee indicated the intent to perform closure testing and increase the testing frequency to once every refueling outage. The licensee stated that since there are no means to verify closure capability during quarterly HPCI testing, these valves will be disassembled, inspected, and manually exercised. The licensee also stated that these valves were noted during the inspections to be seating properly, and no significant degradation was found even though these valves have been in service for more than 20 years. The licensee also indicated its intent to perform a feeler gauge check during future valve inspections to verify that the check valve is seating properly. The failure to test Valve 2(3)-2301-20 is contrary to the requirements of the ASME Code, Section XI and TS 3.0.D (Deficiency 50-237(249)/96201-17). Additional HPCI inservice testing problems are discussed in Section 5.1.5.1.

4.6.2.2 Long-Standing IST Program Deficiencies

The licensee conducted a self-assessment of the IST program in June 1996. This assessment identified continuing problems with the IST program and its implementation, including: (1) miscategorization of code classification of valves; (2) failing to include all components in the IST program; (3) failing to leak rate test Category A valves at functional pressure or extrapolate to functional pressure; (4) failing to repair or replace components when the owner-defined acceptance limits were exceeded; and (5) failing to meet code requirements for calibration error and accuracy requirements for indication instrumentation. The self-assessment concluded that the discrepancies were indicative of broader problems with the administration and implementation of IST requirements.

As discussed in Section 4.6.1, the licensee initiated PIF 237-200-96-18200, on September 18, 1996, which identified discrepancies between the LPCI pump suction relief valve setpoint and the design pressure for the system. The DBDs for the LPCI, CS and HPCI systems identified open items since the DBDs were written regarding the setpoint of the relief valves in those systems. The license initiated a PIF for a CS system relief valve on July 17, 1996, but did not address more than the CS relief valve (Level 4 PIF). The root cause and investigation report for this PIF (237-200-96-18200) stated that in June 1996, during a review of the D2R14 refueling outage activities (February 1996), a concern was raised as to the correct setpoint for the LPCI pump suction relief valve. The relief valve setting exceeded the design pressure given in Specification K-4080. A description of relief Valve RV 2-1599-13D, LPCI pump suction relief valve, attached to the PIF form stated that "Since the torus and LPCI suction piping will not experience these pressures, the urgency in writing this PIF vice investigating the problem was deemed to be low." The NRC will further evaluate the condition of the LPCI suction relief valve, which will be tracked by Unresolved Item 50-237(249)/96201-16.

The problems identified by the licensee's IST self-assessment, and the problems associated with relief valves were indicative of the types of issues identified during the

NRC's 1987 DE. This report identified specific concerns with the implementation of the IST program. In December 1987, the licensee's quality assurance group performed an audit of the IST program and confirmed the findings of the DE. The licensee performed other assessments before 1996 and identified additional IST programmatic concerns.

In 1992 the licensee performed a self-assessment of the IST program, which included a review of the implementation of Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The assessment identified service water system concerns but did not identify specific weaknesses with the IST program; however, the NRC identified problems during the 1993 service water system operational performance inspection (SWSOPI). The SWSOPI identified valves that were included in the IST plan but were not being tested in accordance with the ASME Code. On the basis of these findings from the SWSOPI, the licensee initiated an IST self-assessment. The scope of this self-assessment was expanded in 1994 because of the problems identified during the review of the six systems that were initially selected. The licensee initiated a PIF to address what the licensee's core team determined to be a breakdown in the IST program. The failure to adequately address the long-standing IST program and implementation problems is contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion XVI, and constitutes an additional example of Deficiency 50-237(249)/96201-14.

4.6.3 Safety-Related Battery Testing

The performance of station safety-related battery testing was weak because the licensee had not rigorously tested 125 Vdc and 250 Vdc safety-related batteries. Although the licensee recently improved the rigor of these battery tests, the team determined that the licensee had not adequately demonstrated the capability of the Unit 2, 250 Vdc battery to supply its design basis load.

Two of the battery tests, which the licensee was using to satisfy Technical Specification (TS) requirements, were not performed in accordance with the test procedures. For example, the latest Unit 2, 125 Vdc battery service test performed in February 1993 was not tested as specified by the design load profile. The service test validated the batteries' ability to supply loads under loss-of-power concurrent with loss-of-coolant accident conditions. Procedure DES 8300-28, "Unit 2, 125 Volt Station Main Battery Service Test," required that the battery discharge rate be established in accordance with the load profile, which specified that the battery be discharged at 636.7 amps for one minute and at other specified amperage values for the remainder of the test. However, the test data indicated that the load amperage during the first minute of the test oscillated between 615 and 665 amps. The licensee failed to perform and document an evaluation of this test deficiency before declaring the Unit 2, 125 Vdc battery operable. Failure to test the Unit 2, 125 Vdc battery at the specified amperage value is contrary to the requirements of Procedure DES 8300-28 (Deficiency 50-237(249)/96201-18).

The 1991 performance test of the Unit 3, 250 Vdc battery was not conducted as specified in the Procedure SP-91-10-138, Revision 0, "Unit 3 250 Volt DC Station Battery Performance Test." Problems with the test equipment and instrument setups caused an excessive current discharge rate. The discharge current and the time it takes for the battery to reach the minimum battery terminal voltage of 210 Vdc are utilized to determine the acceptability of the performance test. Because the engineers improperly programmed the test equipment, they were unable to measure the discharge current using the test equipment. Additionally, because the backup test instrument, the strip chart recorder, was also installed incorrectly, the engineers were not able to use the reading from the recorder to measure the rate at which the battery was discharged.

As a result of these testing difficulties, the engineers calculated the discharge current. The engineers calculated that the actual discharge current was approximately 487 A, which was almost twice the current specified by the procedure. Using the calculated 487 A discharge rate, the actual test duration of 1 hour 45 minutes 27 seconds, and the battery discharge curves, the licensee calculated that the Unit 3, 250 Vdc battery capacity was 96 percent. As a result, the licensee implemented corrective actions to increase the capacity of the batteries, which included the addition of four cells.

On November 11, 1996, the licensee initiated a PIF and Operability Assessments 96-37 and 96-46 because of the team's questions about the acceptability of the previous completed TS-required service tests for the 250 Vdc batteries, in view of the recently acknowledged increased duty cycle loading, which is discussed in further detail in Section 5.1.3. The licensee's preliminary calculations indicated that there was only a slight margin in the batteries' capacity to actually carry design basis loads. UFSAR Section 8.3.2.1.1 requires the design of the 250 Vdc electrical distribution system to meet the design basis accident loads of one unit and the safe shutdown loads of the other unit for a 4-hour period. TS Surveillance Requirement Section 4.9.A.3 requires that a service test be conducted each operating cycle to verify that the battery is capable of supplying the loads for the design duty cycle. As a result of the team's findings, the licensee determined that the revised peak loading of the duty cycle was not reflected in the battery service tests performed during the D2R14 (1995-1996) and D3R13 (1994) outages, and the testing was inconsistent with the design peak loading.

The licensee concluded that there was no operability concern with respect to the Unit 3, 250 Vdc battery but there was an operability concern for the Unit 2, 250 Vdc battery, which supplies Unit 3 reactor building loads. The Unit 2 service test indicated that the first minute loading of the revised duty cycle (1013.4 A) was not bounded by the test (960 A for 1.5 seconds and 808 A for 58.5 seconds).

Since Unit 3 was shutdown, the licensee took compensatory action by removing Unit 3 HPCI loads and placing administrative controls on battery loading. Subsequently, the Unit 2, 250 Vdc battery was declared operable in this configuration and the licensee stated it would implement corrective actions before Unit 3 startup. At the conclusion of the inspection, the licensee was considering a modification to delay operation of certain loads or repositioning certain MOVs to reduce the duty cycle. The failure to demonstrate the performance of an acceptable service test of the Unit 2, 250 Vdc battery is contrary to the requirements of TS 4.9.A.3 (Deficiency 50-237(249)/96201-19).

4.6.4 Control Room and East Turbine Building Ventilation System Testing

The control room and east turbine building ventilation systems were operated outside of their design basis for a number of years. The surveillance testing that was performed did not identify long-standing system deficiencies.

4.6.4.1 Control Room Ventilation System Testing Deficiencies

Sections 6.4.2 and 9.4-3 of the UFSAR describe the design basis for the control room HVAC system. Section 6.4.2.4 states that potential adverse interactions between the control room emergency zone and adjacent zones that may allow the transfer of toxic or radioactive gases into the control room are minimized by maintaining the control room at a positive pressure of 1/8-inch water gauge (iwg) during emergency pressurization modes, and with respect to adjacent areas.

On October 8, 1996, the licensee declared the control room HVAC system inoperable because of the inability to maintain the control room at a positive pressure during normal operations and at 1/8 iwg with respect to the surrounding areas in the emergency mode. The control room ventilation system had not been maintained or tested to ensure that the system operated within its design basis. Modifications had been implemented, or partially implemented, which resulted in negative pressure within the control room and the inability to pressurize the control room to 1/8 iwg in the emergency mode. In addition, instrumentation that was used to verify the control room pressure was positive and exceeded 1/8 iwg in the emergency mode had not been calibrated, and had not been installed in accordance with the piping and instrumentation diagram.

In September 1996, the licensee began reviewing open modifications for the control room ventilation system, and subsequently determined that several control room modifications, which had not been completed, contributed to the inability to pressurize the control room as stated in the UFSAR. These modifications were identified as a result of the licensee's efforts to close all modifications or approve their as-built configuration. They included:

- M12-0-87-005-D provided for the installation of security equipment such as bullet resistant plating for walls and ceilings, new east-west kitchen and locker room area, fire and non-fire rated doors, and the sealing of new and unused wall and floor penetrations. Field work was initiated in August 1991 and completed in January 1992. Post-modification testing was not performed.

- M12-0-87-005-E provided supply and exhaust ventilation systems for the new locker room and kitchen areas, new fire dampers in duct work penetrating fire walls, control logic for operation of the isolation dampers, and an interlock for the exhaust fans from the isolation dampers. Field work was started in September 1991 and completed by June 1993. Again the post-modification testing, including logic testing and emergency pressurization testing to verify 1/8 iwg was not performed.

- M12-0-86-006-C provided supply and return side duct silencers, thermally insulated duct work, and manual volume dampers in the shared return duct works. The field work was started in March 1989 and the documentation closure was completed in September 1993. Post-modification testing was not completed.

- M12-0-86-006-D provided for the removal of existing HVAC duct work supports inside the Unit 2 and 3 control room, installed acoustical tile, installed new duct work including hangers and safety chains, reworked existing ductwork inside the control room, and removed existing butterfly dampers inside the control room. The field work was initiated in June 1989 and the work was determined to be completed in May 1993. Post-modification testing was not completed.

In addition, the team concluded that Modification M12-2/3-82-1, which added the HVAC Train B in 1982, was not adequately tested.

Surveillance Procedure DTS 5750-06, Revision 3, "Control Room Standby HVAC Air Filtration Unit, and Refrigeration Condensing Unit Performance Requirements," dated August 24, 1996 only required 1/8 iwg positive pressure in the control room and did not ensure that pressure was greater than 1/8 iwg for the surrounding areas. In addition, the instrumentation used to verify the control room differential pressure (dp) was not calibrated nor verified to be appropriate for the parameters being measured. Specifically, dp Instruments DPI-2-5740-31/32 and 36 for the control room and east turbine building had not been calibrated. The licensee also identified that the control room instrumentation was mislabeled with respect to the areas being sensed and, according to the drawings, other sensing lines were misrouted or were broken. The procedures used to test the control room HVAC system and boundaries were not appropriate to circumstances, contrary to 10 CFR Part 50, Appendix B, Criterion V (Deficiency 50-237(249)/96201-20).

The team reviewed the operability assessment for the control room HVAC concerns. On September 26, 1996, the licensee identified that the control room was not positive relative to the hallway outside the work execution center, and initiated a PIF. On October 1, 1996, the licensee identified that the east turbine building dp relative to the outdoors was not maintained at a positive pressure as identified in the UFSAR. The control room dp instrument indicated that the east turbine building was being maintained at a positive pressure. On October 2, 1996, operations initiated an operability determination evaluation. The initial engineering operability judgment was questioned by the Plant Operations Review Committee (PORC) on October 7, and a 14-day Dresden Administrative Technical Requirement (DATR) limiting condition for operation was entered. The failure to perform a prompt operability determination within the time specified is contrary to the requirements of Procedure DAP 07-31, Revision 3, "Operability Determinations" (Deficiency 50-237(249)/96201-21). Subsequent differential pressure measurements of the surrounding area showed that 1/8 iwg was not maintained.

The following day a special procedure was written that required isolation of the auxiliary computer room and the Train B equipment room. Again a positive 1/8 iwg pressure could not be established. On October 13, 1996, the Train B room and the auxiliary computer were removed from the control room boundary by means of a temporary system alteration. On October 21, 1996, the unfiltered in-leakage was determined to be 520 scfm. A revised operability determination concluded the control room was operable but degraded. Repairs will be completed when leakage is less than 263 scfm, adjacent area dp is 1/8 iwg and maximum filtered airflow is 2200 scfm. The failure to correct long-standing deficiencies affecting the control room ventilation system is contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion XVI, and represents an additional example of Deficiency 50-237(249)/96201-14.

4.6.4.2 East Turbine Building Ventilation System Testing Deficiencies

On October 1, 1996, the licensee initiated a PIF after finding that the east turbine building was at a negative pressure. A negative pressure is contrary to the revised UFSAR (RUFSAR) and UFSAR ventilation description, which indicates that the building is maintained at a positive pressure (the RUFSAR change process corrects inaccurate and incomplete information in the UFSAR). The control room pressure instrumentation also indicated building pressure was positive. The licensee developed a plan to repair the east turbine building ventilation system and return the system to its original design configuration by December 16, 1996.

This PIF also referenced another PIF that was initiated on January 19, 1996, for the east turbine building ventilation system and numerous problems with the system's performance. Twenty-nine deficiencies and recommendations were provided as a result of the system walkdown. The team identified that these 29 items were not entered into the work control process for engineering review or assigned a nuclear tracking system (NTS) number to provide follow up of the issues. These problems included: (1) an incomplete modification that was partially installed in the 1970's that defeated the dp controller for auxiliary electric room and the switch gear room; (2) incorrect piping and instrumentation diagrams (P&ID) that indicated that the east turbine building is maintained at a negative pressure relative to the main turbine building; (3) an inoperable differential controller for the ETRVS exhaust fan vortex dampers; and (4) the low flow alarm for Unit 2, 250 Vdc battery room causing nuisance alarms.

4.6.5 Leak Rate Testing Program Improvements

In March 1996, the licensee conducted an evaluation of the station 10 CFR Part 50, Appendix J test program, identifying approximately 100 valves in each unit were not local leak rate tested in the accident direction. Appendix J requires that valves be tested in the same direction that the valve would experience accident pressure or provide justification for not testing in the accident direction. The affected penetrations have been evaluated and approximately 75 have been tested in the accident direction. Modifications to some of the remaining valves will permit testing in the accident direction or permit more conservative testing in the reverse direction. Justification will be provided for the remaining valves that are not modified.

4.7 NRC Inspection History

The NRC inspection history documented numerous examples of concerns with long-standing material issues involving the maintenance of BOP and safety-related equipment, although the history showed general improvement in plant housekeeping. Maintenance process concerns with planning and scheduling, preventive maintenance, and missed or inadequate PMTs were also documented. Instrumentation out-of-tolerance trends were identified in 1995. The inspection record also documented maintenance performance problems, including implementation of maintenance procedures and inadequate work instructions.

The inspection history documented IST program and implementation problems dating back to the 1987 DE. Other inspections, including the 1992 SWSOPI, identified component testing problems that directly reflected on the adequacy of the IST program. The specific design basis testing deficiencies for the batteries and the control room and east turbine building ventilation systems were not documented, although related issues involving the secondary containment ventilation problems and other inadequate control room modifications were addressed.

5.0 ENGINEERING AND TECHNICAL SUPPORT

The team performed a safety system functional inspection of selected systems. The engineering portion of this inspection involved an in-depth review of the design and calculations for these systems to determine whether the licensing and design bases had been appropriately maintained. The team reviewed a number of evaluations performed by engineering, which included safety evaluations supporting modifications, operability determinations, evaluations of failed equipment, 10 CFR 50.59 safety screenings and evaluations, and Technical Specification (TS) interpretations, to determine the technical quality of the evaluations, and to determine whether the licensing and design bases were maintained. The team reviewed engineering's ability to resolve identified deficiencies. In addition, the team reviewed several licensee responses to NRC inspection report findings and evaluations of NRC generic communications, as well as licensee event reports (LERs) to ensure that regulatory commitments were met. The team reviewed licensee efforts to reduce engineering backlogs to a manageable level and the results of the licensee's efforts to upgrade the Updated Final Safety Analysis Report (UFSAR).

While progress was being made in a number of areas affecting engineering (e.g., addressing configuration management backlogs), and activities reflected increased site management oversight and planning when compared to the past, these efforts were significantly overshadowed by the problems identified during this inspection in the area of design control. The team identified that the licensee was unable to maintain the design bases of the containment cooling service water system under certain conditions, and identified significant weaknesses in the licensee's control of design basis calculations, including a number of errors and nonconservative design assumptions. Some design basis calculations were no longer retrievable, had not existed previously, or were difficult to retrieve. The resolution of some issues was untimely and some commitments were missed. Evaluations of modifications to systems did not always identify system impacts. In some cases, the resolution of issues caused other problems that were not anticipated. These issues reflected (1) the lack of a strong corporate presence in the past to adequately control design basis calculations and the multiple design interfaces, (2) the lack of a challenging and questioning attitude in engineering, and (3) the inability to effectively resolve some long-standing problems.

5.1 Safety System Functional Inspection

The team reviewed selected calculations and design bases documents (including the UFSAR, TS, DBDs, and IPE) to determine whether system design bases were being maintained for the CCSW, 125 Vdc electrical distribution, 250 Vdc electrical distribution, CS, and HPCI systems. The team identified a number of significant weaknesses in several areas of the design control process. The team identified instances in which: (1) the licensee failed to maintain control of calculations; (2) the licensee failed to maintain calculations retrievable; (3) the licensee made errors in calculations or made nonconservative design assumptions; (4) TS, UFSAR, DBD, and drawing discrepancies existed; (5) engineering evaluations were technically weak or not performed (including 10 CFR 50.59 evaluations); and (6) the licensee failed to promptly resolve a number of safety issues. In one case, these weaknesses caused the failure to maintain the specified design requirements for differential pressure in the LPCI heat exchanger under certain conditions, which constituted the creation of an Unreviewed Safety Question (USQ).

5.1.1 Containment Cooling Service Water System

The team identified a number of significant deficiencies associated with CCSW system calculations, which included the use of Low Pressure Coolant Injection (LPCI) system pump curves rather than the CCSW pump curves, nonconservative design input assumptions, and an ineffective system for the control of design basis calculations. These deficiencies resulted in the inability of the CCSW system to maintain the UFSAR- and the TS bases-specified differential pressure in the LPCI heat exchanger to prevent potentially contaminated water from entering the CCSW system and subsequently the river in the event of a heat exchanger tube leak or rupture. The architect-engineer (A/E) failed to identify the failure to meet design criteria when a calculation was performed in 1993 and also when the same calculation was found to contain wrong pump curves in May 1996. The A/E also failed to promptly notify the licensee and assess the impact of the error when it was discovered.

5.1.1.1 Calculation Deficiencies

The team requested copies of all CCSW system hydraulic calculations. Only two calculations (ATD-0191, Revision 2, "Containment Cooling Service Water System Flow Split," dated November 5, 1992; and ATD-0253, Revision 1, "Determination of Flow Restricting Orifices for CCSW Pump Room Coolers and CR Refrigeration Condenser in the CCSW System," dated December 21, 1993) were provided. The team identified that the calculations incorrectly used LPCI pump curves rather than CCSW pump curves in some instances. Calculation ATD-0191 used both CCSW and LPCI pump curves to develop the CCSW system flow distribution, and Calculation ATD-0253 used a LPCI pump curve to calculate the size of orifices that were intended to be installed.

The licensee subsequently confirmed that improper pump curves had been used, initiated PIFs for the occurrences, and evaluated the impact of the wrong pump curves. The licensee's preliminary review of the impact of the wrong pump curves determined no adverse effect for Calculation ATD-0191. The licensee's preliminary evaluation of the wrong pump curves in Calculation ATD-0253 indicated a potential adverse impact on the room cooler sizing; however, on the basis of the results of the actual measured flow rates, the condition was determined to be acceptable.

A licensee contractor subsequently informed the team that another calculation had been identified which also used a LPCI pump curve in place of a CCSW pump curve. This calculation (ATD-0216, Revision 0, "CCSW Pump Discharge Pressure for Surveillance Test Condition Based on 600 second Post-LOCA Initiation Time," dated August 13, 1993) was not provided as part of the team's initial request of all CCSW hydraulic calculations. The purpose of the calculation was to determine whether the TS surveillance test requirements for CCSW pump discharge pressure would ensure that the differential pressure between the CCSW and LPCI systems could be maintained in excess of 8.26 psid.

The licensee informed the team that this calculation was intended to be used to support a license amendment for a one LPCI/one CCSW pump configuration and a two LPCI/two CCSW pump configuration. According to this information, the proposed license amendment was to address establishing a design CCSW flow rate of 5600 gpm. The proposed amendment was also intended to address reducing the differential pressure across the heat exchanger from 20 psid to 8.5 psid. The 20 psid value is specified in UFSAR, Section 9.2.1.2, and the TS Surveillance Requirement Bases, Section 4.5 (A through F). The purpose of maintaining CCSW system pressure greater than LPCI system pressure is to prevent the flow of contaminated water into the river in the event of a LPCI heat exchanger tube leak or rupture during post-LOCA conditions.

The licensee also informed the team that the A/E identified in May 1996 that an incorrect pump curve had been used in Calculation ATD-0216, but the A/E failed to notify the licensee of this until the team identified the problems with the two other CCSW calculations. The licensee initiated a PIF on October 28, 1996, to address the failure of the A/E to make the notification; however, the licensee did not initiate a PIF to deal with the technical aspects of the use of the incorrect pump curves for this calculation until the team reviewed it and identified a number of errors and nonconservative design assumptions:

- The calculation showed that the total developed head (TDH) for the LPCI pump exceeds the TDH for the CCSW pump by approximately 45 psid. This was inconsistent with the design criteria of maintaining a higher pressure in the CCSW system than in the LPCI system.

- The calculation used 10 psig as a maximum torus pressure at 600 seconds into a LOCA. This assumption appeared to be nonconservative and LPCI pressure would increase if a higher torus pressure were used.

- Procedure DOP 1500-02, Revision 26, "Torus Water Cooling Mode of Low Pressure Coolant Injection System," was not revised in 1993 when Calculation ATD-0216 reduced the value of the required differential pressure between the tube side (CCSW) and shell side (LPCI) from 20 to 8.5 psid. The calculation showed that the specified value of 20 psid in the UFSAR and TS bases could not have been achieved at the minimum required flow rate under certain conditions.

- The calculation used a CCSW flow rate of 5600 gpm. The UFSAR specified 7000 gpm for 2 CCSW pump operation. Higher flow rates would increase frictional losses in the CCSW system, and therefore, would result in an even lower CCSW pressure.

- The calculation failed to address the flow required by the control room chillers and CCSW room coolers.

The licensee performed an OE for the impact of using the wrong pump curves, low system flow, and low torus pressure, and determined that under current conditions the CCSW system remained capable of performing its safety-related function. The OE was developed on the basis that: (1) the maximum CCSW flow, which will provide for 20 psid, is approximately 5800 gpm, given a LPCI flow of 5000 gpm; (2) the maximum CCSW temperature that ensures meeting existing design requirements is 84°F at 5800 gpm (CCSW water temperature at the time of the inspection was approximately 60°F); and (3) there have been no detected tube leaks in the LPCI/CCSW heat exchanger in the last 7 years. The team concurred with the licensee's assessment on the basis of the current CCSW water temperature but identified periods when the CCSW water temperature exceeded 84°F.

In summary, the team identified a number of significant deficiencies: (1) errors and nonconservatisms in Calculation ATD-0216 resulted in the CCSW system being potentially inoperable when CCSW water temperature exceeds 84°F; (2) these calculational errors and nonconservatisms had not been identified by the reviewers of these calculations; (3) the lack of control of calculations resulted in not initially identifying all CCSW system calculations; and (4) the results of Calculation ATD-2016 clearly demonstrated that even with the nonconservative assumptions, the 20 psid differential pressure requirement could not be maintained for any of the considered CCSW flow/pump combinations.

Until this inspection, there was no evidence that the licensee recognized the problem, because the UFSAR, the TS bases, and plant operating procedures still specified the 20 psid differential pressure requirement. Procedure DOP 1500-02 required the operators to throttle CCSW flow to achieve 20 psid during a LOCA without any restriction on the minimum required CCSW flow (which would impact the containment analysis). The reduction in margin of the 20 psid pressure requirement appeared to constitute a USQ, as defined in 10 CFR 50.59, that was not submitted to the NRC for review as an application for amendment of the license, contrary to the requirements of 10 CFR 50.59. This constitutes an additional example of Deficiency 50-237(249)/96201-13.

The team's review of the DBD, UFSAR, and ECCS calculations showed that the licensee did not have net positive suction head available ($NPSH_A$) calculations that reflected the licensed plant configuration (i.e., one LPCI pump/two CCSW pumps). The team's review of the existing calculations, which provided some information about the $NPSH_A$, showed a number of errors in the design control of assumptions and inputs.

Calculation MAD 76-198, Revision 0, "Long Term Containment Cooling 4 Pumps," was prepared in response to GE SIL 151, which identified a possibility that a single-active failure could disable long-term containment cooling. This single failure could have resulted in a runout condition for the LPCI pumps, thus disabling long-term containment cooling capability. The team also reviewed Calculation NED-M-MSD-54, Revision 0, "Dresden LPCI/Core Spray Pumps $NPSH_A$ Evaluation," and identified nonconservative assumptions and errors: (1) the licensee assumed a reactor pressure of 56 psig and the maximum hydraulic resistance for the intact loop (both assumptions would lower the predicted LPCI pump runout flow and therefore lower the required NPSH); (2) the maximum short-term torus temperature was assumed to be 130°F whereas a more appropriate value was 143°F; (3) the piping isometric drawings were outdated; and (4) the licensee assumed only three ECCS pumps operating rather than all ECCS pumps drawing suction through the torus header and strainers. The licensee initiated several PIFs to address these issues. While none of these nonconservatisms resulted in system operability concerns, they represented a nonconservative approach to performing calculations.

The team identified that Calculation NED-0-MSD-6, Revision 0, "Torus Bulk Temperature ECCS NPSH Limits," which was the bases for the maximum CS and LPCI pump flows used in Emergency Operating Procedure (EOP) 100, had been superseded by Calculation NED-M-MSD-55, Revision 0, "Dresden ECCS NPSH Temperature Limits." However, Calculation NED-0-MSD-6 had not been identified as having been superseded and it did not reference the more recent calculation. The failure to appropriately control design calculations is contrary to 10 CFR Part 50, Appendix B, Criterion III, Design Control (Deficiency 50-237(249)/96201-22).

5.1.1.2 LPCI Heat Exchanger Macrofouling

As the result of a review of information and discussions with licensee personnel, the team identified that the licensee's tube plugging limits for the LPCI/CCSW heat exchanger did not include any allowances for macrofouling. The licensee's records of inspections of heat exchangers, including pictures of the LPCI heat exchanger tube sheet, showed that some of the tubes were blocked with shells and other debris.

The licensee indicated that macrofouling was addressed every refueling outage on the basis of inspections of these heat exchangers for corrosion, fouling, and biological growth. These inspections included a visual examination of the heat exchanger before any cleaning or maintenance work. The as-found condition would be documented, and samples taken and analyzed. The results of the inspection are recorded in the Heat Exchanger Inspection Report. Macrofouling is monitored on a quarterly basis during surveillance testing, and heat exchanger dp is used as an indicator of fouling. The licensee acknowledged that heat exchanger dp is not an indication of thermal performance. The effects of macrofouling on thermal performance is not addressed and limits for macrofouling have not been established. Flow blockage or degraded heat transfer capability of the heat exchanger could adversely impact the containment ECCS analyses. The licensee stated that it will consider addressing the effects of macrofouling.

5.1.1.3 Control Room Chiller Modification Deficiencies

The control room HVAC system is comprised of Trains A and B. Train A was part of the original plant design and was sized with two 40 ton chiller units. Train A is cooled by a nonsafety-related cooling water supply. From late 1984 to early 1985, Modification

M12-2/3-82-1 added Train B to the control room HVAC system, which was sized with one 90 ton chiller unit. Train B is cooled by the safety-related CCSW system. The team's review of the modification to add Train B revealed the following:

- The 102 gpm-required flow rate for the Train B control room chiller was determined on the basis of a heat exchanger fouling factor of 0.0015, with no allowances for the tube blockage. The Tubular Exchanger Manufactures Association recommended fouling factor value for this type of service is 0.002 to 0.003.

- The original plant design did not include a detailed calculation for the control room heat load. The Train B addition was also not supported by a detailed calculation. Also, there was no hydraulic calculation performed at the time to assess the effect of an additional load on the CCSW system.

- Monitoring of the differential pressure across the control room chiller was incorrectly implemented. The safety-related CCSW system should have been aligned to the chiller; however, the nonsafety-related BOP service water system was used. This issue was identified by the licensee. The licensee initiated a PIF to change the procedure used for monitoring the differential pressure.

The licensee agreed with the team's findings and informed the team that it would evaluate the reverification of key system parameters, beginning with the most risk-significant systems.

5.1.2 125 Vdc Electrical Distribution System

The team reviewed several calculations associated with the 125 Vdc system, identifying a number of deficiencies including the failure to include significant loads and inrush currents, several load discrepancies, some loads considered in the design calculations to be shed that were not included in the appropriate operating procedures, calculations that had been revised were not identified as being outdated, and calculations that used varying cable lengths for the same cable. On the basis of the limited review performed by the team and the number of deficiencies identified, the team concluded that other deficiencies may exist in these calculations. These deficiencies were indicative of: (1) a significant failure to adequately control design calculations; (2) a lack of attention to details in performing calculations; and (3) a lack of a rigorous and challenging design review process. These deficiencies appeared generic to Dresden Station calculations.

5.1.2.1 Nonconservative Sizing Calculation for the 125 Vdc Battery

The 125 Vdc battery sizing calculation was nonconservative because not all loads were accounted for in the battery duty cycle. Specifically, the loads associated with the automatic depressurization system (ADS) pressure relief solenoid valves and the inrush current for several auxiliary dc motors on the emergency diesel generators (DGs) were not included in the duty cycle. Also, several other discrepancies were found in the calculation and the associated 125 Vdc load shedding procedure.

The team evaluated: (1) 125 Vdc battery sizing Calculation 7056-00-19-5 (Sargent & Lundy, Calculation for Load Estimation of 125 Vdc Busses, Revision 30, dated July 29, 1996) for the adequacy of the methodology, the accuracy of the duty cycle load profile, the battery size necessary to supply the load, and the available spare capacity of each battery; (2) Calculation NED-E-EIC-0025 (Sargent & Lundy, GNB NCX-17, NCX-21 and NCX-27 Battery Characteristics Curves, Revision 0, dated September 24, 1993), which incorporates the battery manufacturer's discharge curves into the electrical load monitoring system (ELMS)-DC database; and (3) the calibration records for the ADS 2-minute time delay Relay 287-105A CA.

Calculation 7056-00-19-5 determined the required battery size on the basis of the limiting design basis event of a loss-of-coolant accident (LOCA) concurrent with a loss-of-offsite-power (LOOP). Several significant loads and other less significant loads were not accounted for in Calculation 7056-00-19-5 and related 125 Vdc load shedding procedure. Calculation 7056-00-19-5 did not include the loads associated with the five ADS solenoid relief valves. Specifically, the calculation considered the large-break LOCA scenario and concluded that the ADS electromatic relief valves are not needed; therefore, the ADS solenoid relief valves were not considered to be energized. However, the team reviewed schematic Diagrams 12E-2461, 12E-2461A, 12E-2462, and 12E-2462A and identified, contrary to the calculation, that the ADS solenoid valves would operate under several applicable situations:

- The ADS solenoid valves will operate at 120 seconds after a large-break LOCA.

- On a small or intermediate break, without feedwater or HPCI, ADS must be available to depressurize the reactor vessel and allow use of the CS and LPCI systems. If reactor vessel level cannot be maintained, the ADS may be manually initiated by the control room operator (this could occur no sooner than two minutes after the event) with a permissive signal from a LPCI or CS pump discharge pressure exceeding 100 psig.

- On receipt of a low-low reactor water level signal in conjunction with a high drywell pressure signal and a permissive signal from LPCI or CS pump discharge indicating greater than 100 psig, the ADS could automatically actuate if the 120 second timer failed and actuated immediately without a 120 second delay. The ADS circuitry has dual power sources and the circuit is power seeking (i.e., if power is available from the Unit 2, 125 Vdc battery, the circuit will remain connected to this battery). A postulated failure of the 120 second time delay relay can be considered the single active failure.

- On receipt of a continuous low-low reactor water level signal for 8.5 minutes in conjunction with a permissive from a LPCI or CS pump discharge pressure exceeding 100 psig, the ADS automatically actuates.

Calculation 7056-00-19-5 showed that the DGs have a dc powered fuel oil priming pump and a governor oil booster pump which start when the DG receives a start signal (i.e., 0-5 seconds into the accident scenario). The calculation used the full load current (FLA) to account for the loading on the battery from these pump motors (i.e., 2.7 A FLA for the fuel oil prime pump and 8.04 A FLA for the governor oil booster pump). However, the calculation did not account for the inrush current caused by starting these motors. Typical inrush current is 6 to 10 times the FLA. This additional load occurring in the first minute (0-5 seconds) of the duty cycle affected the calculated battery capacity and voltage profile.

Several additional load discrepancies were identified by the team and subsequently by the licensee:

- The control circuit loading Calculation 7056-00-19-5 (page 222) established for 480 V switchgear Bus 37, fed from dc Bus 3B-2 Circuit 10, was inconsistent with the loading input used in the calculation on page A1087. Specifically, the inconsistencies included: 3.7 A rather than 5.84 A in the 0-5 second interval; 1.8 A rather than 2.04 A in the 5-10 second interval; 3.52 A rather than 3.29 A in the 10-50 second interval; and 1.62 A rather than 1.39 A in the 50 seconds to 4 hour interval.

- The control circuit loading for 480 V switchgear Bus 36, fed from Panel 3B-2 Circuit 11, as described on page 228 of Calculation 7056-00-19-5 indicated that from 50 seconds to 4 hours, the continuous load is 2.27 A. However, the input data on page A1087 of the calculation indicated that this circuit is load shed at the 30 minute point.

- Diesel generator loading Calculation 9389-46-19-2, Revision 0, "Sargent & Lundy, Calculation for Diesel Generator 2 Loading Under design Basis Accident Conditions," showed that 480 V switchgear at Bus 29 for Motor Control Centers (MCCs) 29-5 and 29-6 are tripped on undervoltage (i.e., load shed) under LOCA and LOOP accident conditions; however, the team determined that 125 Vdc battery sizing Calculation 7056-00-19-5 indicated that these breakers remain closed.

Although these issues individually have no significant impact on the results of the calculation, the number of discrepancies was indicative of a lack of attention to detail. In response to the team's concerns in this area, the licensee indicated the following:

- With respect to ADS loads not being included, conservatism existed in the calculation because the switchgear tripping duration that occurs as a result of loss of offsite power was modeled as requiring 5 seconds, but the actual time was only 5 cycles (i.e., 0.08 seconds). For a main steam line isolation event, the calculation remained conservative. However, for ADS operation for a line break, all five valves could operate between 20 seconds and 9 minutes into an event depending on the scenario. Therefore, Calculation 7056-00-19-5 will be revised accordingly to include the loads for the ADS solenoid relief valves.

- With respect to the starting inrush current for the auxiliary dc motors associated with the DGs 2, 3 and 2/3, the inrush current will occur coincidentally with the tripping current of the 4 Kv switchgear, resulting in a new higher peak loading. Therefore, Calculation 7056-00-19-5 will be revised to include inrush current for the DG auxiliary dc motors. In addition, the licensee discovered that the dc load for

DG 2/3 was not incorporated into the duty cycle for the Unit 3 battery. This load will also be included in the revised calculation. These additional loads total approximately 45 A.

- Regarding the discrepancy for the control circuit loading for 480 V switchgear Bus 36 (Panel 3B-2 Circuit 11), this load and three other loads (2B-1 Circuit 10, 2B-2 Circuit 4, and 3B-2 Circuit 15) were identified in Calculation 7056-00-19-5 as being load shed at the 30 minute point to conserve battery capacity. However, the load shed Procedure DGA-13, Revision 6, "Loss of 125 Vdc Battery Chargers with Simultaneous Loss of Auxiliary Electrical Power," did not contain this instruction because Revision 5 of the procedure incorrectly deleted the instruction to load shed these circuits. The licensee stated that Revision 7 to Procedure DGA-13 has been expedited to correct this discrepancy. This discrepancy imposed an additional load of 16.34 A on the battery, but had negligible effect on battery capacity. The licensee further stated that the ELMS loading discrepancy for 480 V switchgear Bus 37 fed from dc Bus 3B-2, Circuit 10, will be revised to reflect the correct data. Finally, the licensee stated that loading Calculation 9389-46-19-2 correctly identified that 480 V switchgear at Bus 29 for MCCs 29-5 and 29-6 are tripped under accident conditions, and the loading for 125 Vdc battery sizing Calculation 7056-00-19-5 will be revised to reflect that these breakers are tripped.

- The licensee initiated a PIF related to this sizing calculation to: evaluate the omission of inrush current for the dc auxiliary motors associated with DGs 2, 3 and 2/3; incorporate the missing loads in Procedure DGA-13; and evaluate the total impact of all the discrepancies in the calculation.

- The licensee stated that additional loading of the battery in the first minute will be largely offset because modification M12-2(3) 91-019A, B, C, and D (performed in 1995 and 1996) changed the 4 Kv breakers from the air circuit breaker design to the SF6 gas design, which resulted in much lower trip and close coil currents. However, Calculation 7056-00-19-5 had not yet been revised to include this change because the design change request (DCR) has not been closed. The DCR, when completed, would have caused revision of the calculation; however, the team noted that the DCR had not been closed even though the work was accomplished approximately 1 year ago.

- On the basis of the team's observations, the licensee revised the duty cycle for Calculation 7056-00-19-5 and performed a preliminary calculation which indicated that the 125 Vdc batteries remained operable. The remaining spare capacity for the Unit 2 battery changed from 12.0 percent to 12.6 percent and the spare capacity for the Unit 3 battery changed from 26.2 percent to 18.0 percent. The licensee stated that the calculation will be revised.

- With respect to generic implications, the licensee stated that a technical alert will be issued to other ComEd facilities concerning: (1) the omission of DG auxiliary dc motor inrush currents; (2) the appropriate revision level of procedures used as design inputs to calculations; and (3) the operation of ADS solenoid relief valves.

- The licensee also evaluated the 125 Vdc batteries, using the revised loading for the period before the modification that installed the SF6 gas circuit breakers, and determined that the batteries remained operable. The remaining capacity for the Unit 2 battery was marginal. The Unit 2 battery had a remaining spare capacity of 0.6 percent and Unit 3 had a margin of 8.6 percent.

Although the calculation required revision and the battery spare capacity for Unit 3 was reduced, the 125 Vdc batteries remained operable. The omission of electrical loads in the battery sizing calculation, and the discrepancies in the load shedding procedure and in the calculation constitute additional examples of Deficiency 50-237(249)/96201-22.

5.1.2.2 Invalid 125 Vdc System Calculations

The team reviewed voltage drop calculations associated with the 125 Vdc system to ensure that the voltage applied to equipment during design basis accident conditions was sufficient to allow the equipment to perform as required. Many voltage drop calculations of record for the 125 Vdc system were no longer accurate because design inputs were changed, and there appeared to be no process to alert the engineering staff that the calculations were no longer valid.

Calculation 9389-68-19-2, Revision 0, "Sargent & Lundy, Calculation for Voltage Adequacy of Swing Diesel Circuit Breaker Closing Coils," determined the available voltage for pickup of the DG 2/3 circuit breaker closing coil at 4 Kv switchgear Bus 23-1 during a LOCA concurrent with a LOOP. The calculation used, Calculation 8982-66-19-1, Revision 1, "Sargent & Lundy Calculation, 125 Vdc Bus Voltage Calculations for Dresden Station," as design input for the 125 Vdc system voltage at switchgear Bus 23-1. This design input was identified as 92.1608 Vdc at switchgear Bus 23-1. Using this design input, the voltage at the closing coil was 84.74 Vdc to 86.0 Vdc (considering applicable tolerances). Although the calculated available voltage was below the manufacturer's minimum voltage requirement for the closing coil (i.e., 90 Vdc), the calculation used test results conducted at Dresden Station to establish that the voltage at the closing coil was adequate for pickup (i.e., 70 Vdc was the minimum pickup voltage).

The design input for dc system voltage at switchgear Bus 23-1 was changed by Calculation 8982-66-19-1, Revision 4, "Sargent & Lundy Calculation, 125 Vdc Bus Voltage Calculations for Dresden Station." Revision 4 of Calculation 8982-66-19-1 identified the bus voltage as 90.5706 Vdc at switchgear Bus 23-1. Since the voltage at the bus changed to a lower value, the available voltage at the closing coil would also be several volts lower. However, the team determined that Calculation 9389-68-19-2 was neither revised nor annotated to be affected by the new design input. The calculation was no longer accurate or conservative. The results of the calculation indicated that the revised design input voltage for the bus causes only a small overall reduction in voltage at the closing coil; therefore, the calculated value remained acceptable. The design inputs to calculations were not being controlled, and there appeared to be no design control mechanism to convey this information to site engineering personnel (e.g., design change notice, calculation change notice or another similar mechanism).

In response to this issue, the licensee stated that other voltage calculations that used design inputs have subsequently been changed and the associated calculations not revised. As top-tier calculations change and output data used as design input for other calculations also change, the lower-tier calculations were not revised. Engineering judgment was used to determine whether the impact on the calculation conclusions was significant. The licensee indicated that this method of configuration control applied to mechanical, electrical and structural calculations, and acknowledged that the engineering staff would be challenged to perform detailed evaluations using design calculations in a short period because of the present state of the calculations. The failure to control design inputs was contrary to 10 CFR Part 50, Appendix B, Criterion III, Design Control, and constitutes an additional example of Deficiency 50-237(249)/96201-22.

The team identified other design control issues. At the time of the inspection, the Dresden Station calculation database listed Calculation 8256-11-19-1, Revision 0, "Sargent & Lundy, Dresden 125 Vdc System Short Circuit Currents," and Calculation 5569-31-19-1, Revision 1, "Sargent & Lundy, 125 Vdc Fault Currents," as the calculations of record for 125 Vdc system fault currents. The licensee stated that Calculation 5569-31-19-1, Revision 1, was the appropriate calculation of record because this calculation was updated to reflect the installation of a larger capacity main battery, larger capacity battery chargers, and more specific data on cable length and size. The licensee stated that Calculation 8256-11-19-1 used input from Revision 0 of Calculation 5569-31-19-1, which did not include the more recent data; therefore, Calculation 8256-11-19-1 would be "voided" to ensure that the current plant configuration was documented. However, the team identified that Calculation DRE96-0184, Revision 0, "ComEd Limited Short Circuit Study, 125 Vdc Busses," prepared during this inspection, used Calculation 8256-11-19-1, which was no longer valid as design input for cable lengths.

The licensee conducted an evaluation of Calculation DRE96-0184. Although some cable lengths and cable resistances were found to be incorrect and required revision (some were conservative and others were not), the licensee determined that the calculated fault currents were within the capability of the protective devices and the basic conclusions of DRE96-0184 remained unchanged. The team concluded that this is another example of a lack of design control of design inputs and design basis calculations, and constitutes an additional example of Deficiency 50-237(249)/96201-22.

5.1.2.3 Cable Length Configuration Control Deficiencies

There was a lack of configuration control for cable lengths used as design input in 125 Vdc system design basis calculations for voltage drop and short circuit current. Calculations were inaccurate and in some cases nonconservative because of discrepancies in cable lengths.

The team reviewed Calculation 5569-31-19-1, Revision 1, "Sargent & Lundy Calculation for 125 Vdc Fault Currents," which determined the maximum short-circuit current available within the 125 Vdc system and compared this fault current to the interrupt rating of the system circuit breakers. Accurate cable length is important because the cable resistance is one factor in the determination of available short-circuit current, load flow, and voltage drop. The team identified several discrepancies in cable lengths used in these calculations.

- For cable Run Rc3 between 125 Vdc Battery 2 and Bus 2, fault current Calculation 5569-31-19-1 identified the positive and negative cables as cable numbers 24160 and 24161/24163, and assigned a 2-way total length as 71 ft for the calculation of the available short-circuit current at the bus. Voltage Calculation 8982-66-19-1, Revision 4, "125 Vdc Bus Voltage," identified these cables as cable numbers 67295 and 67296 and assigned a 2-way length as 98 ft for the calculation of voltage at the bus. Sargent & Lundy ELMS database identified these cables as cable numbers 67295 and 67296 and assigned a 2-way total length as 48 ft. The cable numbers for the circuit between Battery 2 and Bus 2 in Calculation 5569-31-19-1 were not consistent with the ELMS database and Calculation 8982-66-19-1, and the total cable length was different in all three documents.

- For cable Run Rc9 between 125 Vdc system turbine building main Bus 2A-1 and reactor building Panel 2, fault Calculation 5569-31-19-1 identified the positive and negative cables as cable numbers 24196 and 24197 and assigned a 2-way total length as 1538 ft for the calculation of the available short-circuit current at Panel 2. Voltage Calculation 8982-66-19-1 assigned a 2-way length for these cables as 1434 ft for the calculation of voltage at the panel. The cable length in Calculation 5569-31-19-1 was inconsistent with the cable length used in Calculation 8982-66-19-1.

In response to these inconsistencies, the licensee determined that in certain cases the cable lengths were nonconservative, but in no case was component or system operability challenged. On October 28, 1996, the licensee issued Calculation 5569-31-19-1, Revision 2, "ComEd Calculation for 125 Vdc Fault Current," which represented a complete revision to the calculation. Although cable lengths and resulting fault currents changed, the basic conclusions of the calculation remained unchanged.

With respect to the generic issue of cable configuration, the licensee stated that it did not retain cable pull cards during original installation; therefore, installed cable lengths were not fully documented. Several attempts were made over the years to improve the accuracy of cable length data for use in design calculations. In 1985 the cable length data were transitioned into the ELMS database. At present, all cables installed in cable trays were entered into ELMS; however, in general, cables installed in conduit to equipment were not included in ELMS. For calculations, the licensee used various methods such as drawings and walkdowns to determine the cable length in conduit. The licensee stated that if accurate cable lengths were not critical to the analysis, cable lengths from ELMS (without end lengths) would be used in calculations; however, if more accurate data were required, walkdowns and drawing reviews would be necessary to obtain the cable lengths for calculations.

The team concluded that there was a lack of configuration control for cable lengths used as design input for 125 Vdc design basis calculations that determine voltage and fault current. Calculations were inaccurate and in some cases nonconservative because of discrepancies in cable lengths. However, these discrepancies did not change the basic conclusions of the calculations; therefore, safety functions were not degraded. The lack of configuration control, incorrect design inputs, and incorrect calculations are contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion III, Design Control, and constitute additional examples of Deficiency 50-237(249)/96201-22.

5.1.3 250 Vdc Electrical Distribution System

The team reviewed selected 250 Vdc system calculations, finding that the licensee used an inappropriate load interval design methodology that resulted in increased loading of the 250 Vdc batteries and that a calculation referenced a nonexistent design input. The team concluded that the licensee's and A/E's design review process did not ensure that design methodologies were appropriate to the circumstances and that design inputs were properly verified.

5.1.3.1 Nonconservative Sizing Calculation for the 250 Vdc Battery

The team determined that the 250 Vdc battery sizing calculation was nonconservative because it did not accurately determine the battery duty cycle loading. The licensee subsequently determined that the original methodology was not justified. This methodology resulted in additional battery loading, reduced available spare capacity, and reduced terminal voltages.

The team reviewed 250 Vdc battery sizing Calculation PMED-898230-01, Revision 10, "Sargent & Lundy Calculation for Development of a Duty Cycle Based on a More Conservative Application of Coincident Starting Currents for the 250 Vdc Battery System," to evaluate the adequacy of the methodology, the accuracy of the duty cycle load profile, the battery size necessary to supply the load, and the available spare capacity of each battery. This calculation determined the duty cycle loading on each 250 Vdc battery on the basis of a detailed system evaluation of equipment required to operate under various scenarios. The large break LOCA concurrent with dual unit LOOP and the HPCI system in the standby mode was the bounding case for sizing the 250 Vdc batteries. Calculation PMED-898230-01, Revision 10, determined that the batteries were adequately sized and the remaining spare capacity (margin) was 29.8 percent for the Unit 2 battery and 29.6 percent for the Unit 3 battery.

Calculation PMED-898230-01 indicated that the battery experiences the largest loading during the first minute of the duty cycle and the required battery size is governed by the first minute time interval. To demonstrate adequacy of the battery, the calculation methodology treated loads that energize in the first minute as discrete momentary loads (i.e., short duration loads), which is consistent with guidance provided in IEEE Standard 485-1983, "Recommended Practice for Sizing Large Lead Storage Batteries for Generating Stations and Substations." Because of the number of starting loads and the high inrush currents, the calculation used four very short, discrete time intervals within the first minute. Specifically, the time intervals were: 0 to 1 second; 1 second to 2 seconds; 2 seconds to 3 seconds; 3 seconds to 25 seconds. The calculation showed that the largest loading occurs between 1 second to 2 seconds, which was calculated to be 909.5 A for the Unit 2 battery and 912.0 A for the Unit 3 battery.

The team questioned the validity of the very short, discrete loading periods used in Calculation PMED-898230-01 because the team determined that the calculation did not contain sufficient data to justify the use of 1 second intervals. If an overlap of loads into adjacent time intervals occurred, the loading on the battery would increase, resulting in a reduced voltage that may degrade the safety function of connected equipment.

The licensee re-evaluated the modeling of the first minute of the duty cycle, and determined that the control circuit testing indicated that some relays actually operated significantly faster than the published values. The evaluation of the duty cycle using the actual operating time for the relays resulted in overlapping of loads (inrush currents) into the critical 1 to 2 second period for the actuation of Valves MO 2(3)-2301-15 (HPCI test return isolation valve), MO 2(3)-2301-48 (cooling water return to HPCI pump suction), and MO 2(3)-2301-49 (cooling water return to CST). This overlapping of loads into this period resulted in an additional load of 103.9 A for the Unit 2 battery (load increased from 909 A to 1013.4 A) and 101.4 A for the Unit 3 battery (load increased from 912.0 A to 1013.4 A). As discussed in Section 5.1.5.1, the standby alignment of these valves was changed in 1982 as a result of a design deficiency associated with the HPCI gland seal leak off (GSLO) condenser limit switches. In the original HPCI standby alignment, these valves would not have had to reposition nor actuate in the event of HPCI system initiation.

On October 31, 1996, the licensee initiated a PIF to document the discovery of the overlap of loads for certain MOVs and the need to revise Calculation PMED-898230-01. The licensee incorporated the increased loading because of the overlapping, inrush currents, included a 125 percent aging factor, and performed a preliminary calculation that indicated the 250 Vdc batteries remained operable with a spare capacity of 2.3 percent for both the Unit 2 and Unit 3 batteries. The licensee stated that the calculation will be formally revised to incorporate these issues. The incorrect calculation constitutes an additional example of Deficiency 50-237(249)/96201-22.

The team concluded that the licensee's calculation review process and engineering management oversight was weak. The reviewer and engineering managers should have questioned the use of very short, discrete periods in the calculation and required confirmatory testing to justify the analysis of the duty cycle.

On the basis of a review of the Dresden Station design and licensing bases documents, the team determined that sizing and testing of the station batteries were required to conform to the guidance and methodology provided in IEEE 450-1975, "Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations," and IEEE 485-1983. IEEE 485-1983 (Section 6.2.3) and IEEE 450-1975 (Sections 4 and 5) recommend that an aging factor of 125 percent be used when sizing and determining the capacity of the battery, and the battery should be replaced when actual capacity (determined by test) drops to 80 percent of rated capacity. A constant current capacity test (performance test) is periodically conducted on an in-service battery to detect any change in capacity and IEEE 450-1975 (Section 6) recommends that a battery be replaced if the capacity is determined by test to be below 80 percent, which is indicative that the rate of deterioration is increasing. There is a direct correlation between the aging factor and the acceptance criteria of 80 percent, which is specified in TS Surveillance Requirement 4.9.A.4.

Contrary to industry practice and the guidance provided in IEEE 485 and IEEE 450, the 250 Vdc battery sizing Calculation PMED-898230-01 used no aging factor to determine the required cell size and the spare capacity (margin). The calculation determined that the Unit 2 battery had 29.8 percent spare capacity and the Unit 3 battery had 29.6 percent spare capacity. The batteries were shown to have adequate spare capacity slightly in excess of that required to support a 125 percent aging factor. The team concluded that the lack of an aging factor was a potential vulnerability because the calculated spare capacity must be carefully tracked to ensure that the actual capacity of the battery does not fall below that required to carry design loads at the end of battery service life.

The failure to incorporate an aging factor was identified during a previous NRC inspection. The Design Basis Document Manual DBD-DR-006 referred to NRC Electrical Distribution System Functional Inspection (EDSFI) Report 50-237/91-201 and 50-249/91-201, dated September 20, 1991, Deficiency 91-201-04. The EDSFI deficiency described that because of limited capacity margin of the 250 Vdc batteries and the lack of an aging factor, a potential existed for the battery to become inoperable and not be recognized as inoperable. In response to the EDSFI deficiency, the licensee stated in a ComEd letter to NRC dated November 4, 1991, that once the modifications to add four cells were completed, both 250 Vdc batteries would include an aging factor and design margins as recommended by IEEE 485, and the minimum acceptable capacity for the battery will be 80 percent of rated capacity.

Also, a meeting conducted between the licensee and NRC in November 1991, concerning Unit 3 battery service test failures, indicated that available margin at that time was only 16.6 percent. This would require the battery capacity to be a minimum of 86.2 percent in order to meet design requirements. Additionally, Section 4.27 of NRC NUREG-0823, "Integrated Plant Safety Assessment-Systematic Evaluation Program, Dresden Unit 2," dated February 1983, stated that rated capacity tests would be conducted to verify that the battery capacity is equal to or greater than 85 percent of the manufacturer's ratings, which was indicative of the application of a 125 percent aging factor. The failure to implement corrective action to account for 250 Vdc battery aging margin constitutes an additional example of Deficiency 50-237(249)/96201-14).

Calculation PMED-898230-01 was first prepared in 1991 after the service test failure on the Unit 3 battery. The initial version of the calculation could not support a 125 percent aging factor and Procedure DEP 8300-20, Revision 0, "250 Vdc Station Battery Performance Test," stated that the battery would be declared inoperable if the capacity dropped below 90 percent. By Revision 6 of the calculation, loads had been reduced on the battery and four cells were added, thereby increasing the capacity. However, in updating the calculations, the aging factor was not included. The licensee has now incorporated a 125 percent aging factor.

The 250 Vdc battery sizing calculation was nonconservative because it did not accurately determine the duration of discrete momentary loads on the battery, and the overlap of inrush currents created a new duty cycle loading. The calculation was required to be revised, and an aging factor was required to be incorporated into the battery sizing. Preliminary calculations revealed that the battery spare capacity has been significantly reduced.

5.1.3.2 Unsupported Design Input Data

Multiple contractor engineering firms perform design calculations for Dresden Station. The calculation performed by one engineering firm involving degraded terminal voltage at 250 Vdc MOVs used a design input for minimum battery terminal voltage from another engineering firm that was not supported by the documentation. In addition, the licensee had not performed a calculation which determined the voltage profile at the terminals of the 250 Vdc batteries during the design basis event.

Vectra Calculation DRE96-0126, Revision 0, "Motor Terminal Voltage Calculation for Dresden 250 Vdc Motor-Operated Valves," determined degraded terminal voltage at MOVs for the torque computations conducted under the NRC Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," program. The calculation stated that the minimum terminal voltage at the 250 Vdc battery during the worst-case design basis accident scenario is 213 Vdc as calculated in Sargent & Lundy Calculation PMED 898230-01, Revision 10, "Development of a Duty Cycle Based on a More Conservative Application of Coincident Starting Currents for the 250 Vdc Battery System," which was identified and referenced as Attachments C and H to Calculation DRE96-0126. To be conservative, Calculation DRE96-0126 used a minimum battery terminal voltage of 210 Vdc as design input consistent with UFSAR Section 8.3.2.1.1 to determine voltages at the MOVs. The team determined that Attachments C and H of Calculation DRE96-0126 did not address minimum battery voltage. The attachments are copies of the Unit 2 and Unit 3, 250 Vdc ELMS battery sizing load sheets. The referenced Calculation PMED-898230-01 only addressed battery sizing and did not address the battery voltage profile. Therefore, Calculation DRE96-0126 used an unsupported and nonexistent design input of 213 Vdc for comparison with the UFSAR bounding design basis requirement of 210 Vdc.

The licensee stated that a 250 Vdc battery voltage profile calculation had not been performed for Dresden Station. On November 2, 1996, the licensee provided Calculation DRE96-0189, Revision 0, "Voltages on Loads Fed from the Safety Related 250 Vdc Batteries," which indicated that the minimum battery terminal voltage was 218 Vdc. This calculation, which determined the degraded voltages at the HPCI auxiliary motors powered from the 250 Vdc system, was initiated by the licensee because of the team's questions relating to the 250 Vdc system.

Calculation DRE96-0126 was conservative. Nonetheless, the team identified at the time of its review of Calculation DRE96-0126, that there was no calculation that determined the voltage profile for the 250 Vdc batteries during the limiting design basis event, and the design input used for evaluating the calculated minimum battery terminal voltage was not supported by the documentation. This calculation demonstrated the lack of a battery voltage profile calculation for the 250 Vdc batteries and the use of a design input that was not supported by the documentation. This constitutes an additional example of Deficiency 50-237(249)/96201-22.

5.1.4 Core Spray System

The team reviewed selected CS system calculations and analyses, and identified that the licensee had not been consistently evaluating core bypass leakage. The team identified the use of some nonconservative assumptions. Some inconsistencies were noted in the UFSAR and DBDs. Also setpoint error calculations used unsupported assumptions.

5.1.4.1 Core Spray Bypass Leakage Evaluation Weaknesses

The licensee performed LOCA analyses to demonstrate that ECCS equipment met the criteria specified in 10 CFR 50.46. Part of the analyses is to ensure that the fuel element peak cladding temperature (PCT) remains below 2200°F. The original and the 1988 PCT analyses were developed on the basis of flow of 4500 gpm per train, or a total flow of 9000 gpm per unit with a reactor pressure of 90 psig, and total flow of 11,300 gpm with a reactor pressure of 0 psig.

Technical Specification (TS) Surveillance Requirement 4.5.A.1.b states that CS pumps shall deliver at least 4500 gpm against a system head corresponding to a reactor vessel pressure of 90 psig. The surveillance test procedure verifies this requirement on the basis of a flow rate of 4600 to 4650 gpm at a discharge pressure of greater than or equal to 235 psig. The design basis document attributed the difference between the flow of 4600 to 4650 gpm measured at the pump and the flow of 4500 gpm required to be delivered to the core to allow for core bypass leakage of 100 gpm.

In 1994 the licensee identified cracks in the Unit 3 CS piping. General Electric (GE) Safety Evaluation for Unit 3, GENE-771-33-0594, "Core Spray Sparger Riser Repair," dated May 1994, identified a maximum calculated leakage of 197 gpm per CS loop. The 10 CFR 50.59 evaluation performed by GE determined this leakage to be acceptable because of the CS pump's specified capability of 4700 gpm with the reactor at 90 psig. The licensee's review of this leakage was documented in a memorandum dated June 1, 1994, and it concluded that the CS pumps have an adequate margin to deliver flow of 4500 gpm (the LOCA analysis-required flow delivered to the core) even if 200 gpm of the pump flow is diverted away from the core. In 1995 the licensee also identified cracks in the Unit 2 CS piping. The estimated leakage from these cracks was less than the Unit 3 estimated leakage.

ComEd letter to NRC, dated January 12, 1996, 30 Day 10 CFR 50.46 Report, indicated a reduction of the PCT from 2045°F to 1884°F for Unit 2 and 1856°F for Unit 3. The reduced PCT's included the contribution of a change in fuel from 8x8 to 9x9 and a reduction in CS flow delivered to core from 4500 to 4318 gpm for Unit 2 and 4185 gpm for Unit 3. The CS flow reductions included a more precise accounting of the various leakage paths. However, the flow leakage estimates were still developed on the basis of the original value of thermal sleeve leakage and did not account for instrument errors.

In mid-1996 questions about the accuracy of the assumptions for the thermal sleeve leakage were raised by the licensee. In October 1996, the results of calculations demonstrated that the thermal sleeve leakage was greater than that used in the analysis to support the January 12, 1996, letter. The licensee initiated a PIF for the effect of the increased thermal sleeve leakage on the PCT limits. The results of additional PCT analysis demonstrated that the PCT remained less than 2200°F. The licensee initiated an additional PIF to address the effect of instrument error on PCT. The combined effect of the increased thermal sleeve leakage and instrument error increased the PCT to a value 2028°F for Unit 2 and 2149°F for Unit 3.

ComEd letter to NRC dated November 6, 1996, Plant Specific ECCS Evaluation Changes - 10 CFR 50.46 Report, provided a revised PCT value of 2030°F for both units. The analysis supporting the November 1996 letter accounted for the increase in the thermal sleeve leakage; however, this analysis assumed end of cycle assumptions for the size of the CS piping crack and other inspectable leakages whereas the analysis supporting the January 12, 1996, letter assumed end of life leakages. Both letters did not provide any allowances for instrument errors.

An additional ComEd letter to NRC, dated November 6, 1996, Core Spray System Flow Requirements, addressed inconsistencies in accounting for the CS system leakage. This letter also acknowledged the need to clarify the requirements in the UFSAR, the TS bases and the DBDs, and the need to evaluate methods to address ECCS flow and pressure instrument uncertainty.

The 1994 reviews performed by GE and the licensee used nonconservative assumptions in evaluating the pumps' ability to deliver the required flow under accident conditions. This evaluation neglected system frictional losses, which are approximately 130 psid as indicated by preoperational test data, and used only reactor backpressure. The licensee initiated a PIF to review this issue. Additionally, the pumps' capability to deliver the required design flow was not supported by calculations. The licensee was performing recalculations to demonstrate the adequacy of the surveillance testing, which is further discussed in Section 5.1.6.

5.1.4.2 Discrepancies Among UFSAR, DBDs, and Calculations

The team reviewed instrument setpoint calculations for the CS pipe break/leak detection system and identified inconsistencies between the calculations, the DBD, and the UFSAR. Subsequent discussions with the licensee indicated that these discrepancies had also been found by the licensee in the enhanced UFSAR reviews performed just prior to the initiation of this inspection.

The instrumentation is designed to initiate an alarm if a CS line break or leak is detected inside the reactor vessel, between the reactor vessel wall and the core shroud. Upon detection of a drop in differential pressure (dp), an alarm actuates in the main control room. During normal full power operation, the dp sensed by the transmitters is equivalent to approximately +3 psid. The current setpoint of the dp switch is -4.7 iwg (approximately -0.17 psid). A substantial loss of core spray line integrity at full power will result in a dp of approximately -1.5 psid at the transmitters, which will generate an alarm.

Modifications M12-2(3)-80-03 were performed in both Units 2 and 3 in 1982 to eliminate generic boiling water reactor (BWR) problems with nuisance alarms during startup and shutdown. This modification changed the connection of the instrumentation piping and the setpoint of the dp switch to the current setpoint. However, the UFSAR and the DBD were not revised to reflect these changes. The team identified the following inconsistencies: (1) UFSAR, Section 6.3.2.1.3.3, stated a rise of 0.5 psid would cause a control room alarm; (2) Core Spray DBD DR-028, Section 4.1.4.7, indicated a setpoint of 5 psid; and (3) Calculation NED-I-EIC-0143, Revision 2, August 24, 1994, indicated a setpoint of -4.7 iwg. The licensee determined that the setpoint in the calculation was correct and that it was in accordance with the field conditions. The DBD and the UFSAR were both incorrect, and the licensee issued PIF 96-9559 to correct the noted discrepancies. The failure to update the UFSAR is contrary to the requirements of 10 CFR 50.71(e) (Deficiency 50-237(249)/96201-23).

Section 6.3.2.1.3.3 of the UFSAR indicates that under loss-of-offsite power conditions, the CS pumps receive a start signal 10 seconds after power is available, which is consistent with the times specified in UFSAR, Tables 8.3-4, 8.3-5, and 8.3-6. However, UFSAR Table 6.3-4 indicates that the CS pumps start 30 seconds after the design basis accident (17 seconds after power is available). The licensee indicated that the times specified in Table 6.3-4 included the maximum DG start time and relay resetting delays. These were not reflected in UFSAR, Tables 8.3-4, 8.3-5, and 8.3-6. The start times for LPCI pumps were also inconsistent in Table 6.3-4. The licensee acknowledged that these inconsistencies were not well explained in the UFSAR. The licensee stated that these sections of the UFSAR could be clarified.

5.1.4.3 Unsupported Assumptions in Setpoint Calculations

Core spray dp transmitter setpoint Calculation NED-I-EIC-0143, Revision 2, "Core Spray Header Differential Pressure Transmitter, Trip Unit, and Indicator Calibration Setpoint Error Analysis at Normal Operating Conditions," dated August 22, 1994, stated that instrument errors based on environmental conditions (i.e., temperature, humidity, pressure, and radiation) were assumed to be included in the manufacturers' accuracy specification. The bases for this statement was not documented. Acceptance of these assumptions allowed for possible nonconservatism in the consideration of errors because possible errors introduced by temperature, humidity, pressure, and radiation were disregarded. The assumptions made in the calculations appeared to be contrary to ComEd TID-E/I&C-20, Revision 0, "Bases for Analyses on Instrument Channel Error and Instrument Loop Accuracy," because the guidelines specified that these errors be taken into consideration.

The licensee's review of the issues raised by the team determined that new information was available for the Foxboro transmitter. PIF 96-9702 was initiated to include specific error data for ambient temperature effects. However, no changes were required to the existing settings in the calibration procedures because the current settings bounded the newly considered errors. The failure to have appropriate design input information was contrary 10 CFR Part 50, Appendix B, Criterion III, Design Control, and constitutes an additional example of Deficiency 50-237(249)/96021-22.

5.1.4.4 Unfused/Ungrounded Motor Control Circuits

While performing a review of the CS system, the team identified that 120 Vac CS pump motor control circuits were ungrounded and did not have short-circuit protection (unfused).

This configuration was typical of the other Dresden Station ECCS pumps and motors. These circuits energize relays to start pumps and motors and provide power to indicating lights. The unfused and ungrounded configuration was contrary to the current industry accepted method of providing fuse protection and grounding of one side of the circuit. The licensee's approach for unfused and ungrounded control circuits was part of the original design, specified by Sargent & Lundy, in Specification Form 1817-E, dated March 18, 1964. This design, with the lack of a fixed ground reference potential, rendered the circuits vulnerable to the possibility of the development of multiple undetected ground faults. Also, a lack of short-circuit protection could lead to failure of equipment.

The licensee stated that the original design approach was discontinued in the mid-1970's in favor of the currently accepted method that includes grounding and fuse protection. In the licensee's view, the use of fuses was unreliable and could cause circuit malfunction if they failed to open. To support not having fuse protection, the licensee stated it had experience with the safe clearing of faults by the failure (burn-up) of the control transformers feeding the circuits. The licensee maintained, on the basis of its experience and laboratory testing performed by others, that the failure of the control transformer was the only impact of a short circuit. The team estimated that the transformer would take approximately 2000 times longer than a fuse to clear a short circuit, and that this longer clearing time could result in more extensive damage to other equipment and wiring. Greater heat impact could occur in the small MCC compartments where the transformer is actually located than in the laboratory or shop facility where the transformers were tested. Although the team disagreed with the licensee's position, the current design was consistent with the licensing basis of the plant.

5.1.4.5 Non-Class 1E Pump Motor Space Heaters

Section 1.3.2.8 of the CS DBD stated that the CS pump space heaters are powered from a non-Class 1E power supply. After discussions with the licensee, the team was informed that the heaters were actually powered from a Class 1E power supply, but that the heaters were non-Class 1E. The licensee indicated that the space heaters were not required because none of the pump motors were subjected to humidity. While this configuration met the licensing basis of the plant, the team considered it to be a vulnerability to the 1E power supply.

5.1.5 High Pressure Coolant Injection System

The team reviewed selected HPCI system calculations to determine whether the design and licensing bases had been maintained, identifying that when some HPCI valves had their normal positions changed, not all affected system and design impacts were addressed. System modifications were made without a complete evaluation of the change and some setpoint calculations had unsupported assumptions.

5.1.5.1 Component Configuration Deficiencies

There were no open and close inservice testing stroke time requirements specified for several HPCI motor-operated valves (MOVs). In response to the team's questions, the licensee stated in a written response that: (1) Valves MO 2(3) 2301-15 and MO 2(3)-2301-49 were normally closed valves that were required to remain closed following the initiation of the HPCI system; and (2) Valve MO 2(3)-2301-48 was normally open and was designed to stay open following the initiation of the HPCI system. However, Valves MO 2(3)-2301-15 and MO 2(3)-2301-49 were actually normally open and automatically reposition closed following the initiation of the HPCI system, and Valve MO 2(3)-2301-48 was normally closed and automatically repositions open following the initiation of the HPCI system.

The original standby alignment of these valves was first changed in 1982 to compensate for a design deficiency involving the HPCI GSLO condenser hotwell drain pump. The level switch that automatically starts the pump is located approximately 2 inches below the GSLO condenser high level alarm level switch; therefore, the pump would start before a high level was indicated in the control room. This resulted in the pump operating against a shutoff head, without operator knowledge. The standby alignment of the subject valves was changed to provide a flowpath to the condensate storage tank. Although the realignment of these valves was approved in Onsite Review No. 81-2, no 10 CFR 50.59 evaluation was conducted for the change in the standby alignment of these valves.

Subsequently, the Unit 2 valves were realigned to their original standby alignment following an event in March 1990 in which feedwater back leakage through Valve MO 2(3)-2301-10 (HPCI test return valve) was identified, as discussed in LER 2-89-029, Revision 4. The valve alignment was subsequently changed again in 1991 following the repair of Valves 2-2301-7, MO 2-2301-8, and MO 2-2301-10. A 10 CFR 50.59 evaluation was performed for changing the Unit 2 valves back to the original standby alignment; however, a 10 CFR 50.59 evaluation was not performed to change the alignment of these valves back to their current positions. These failures to perform 10 CFR 50.59 evaluations constitute additional examples of Deficiency 50-237(249)/96201-13.

The team also identified the following additional problems: (1) the HPCI piping and instrumentation Diagrams M-51, Revision BB, and M-374, Revision BM, depicted the valves in the wrong position, which constitutes an additional example of Deficiency 50-237(249)/96201-22; (2) the diagram of the HPCI system in the UFSAR depicted these valves in the wrong position, and the licensee failed to correct the depiction of these valves during previous 10 CFR 50.71 updates to the UFSAR, which constitutes an additional example of Deficiency 50-237(249)/96201-23; (3) according to background information attached to a PIF dated October 28, 1996, the design basis document for MOV differential pressure determination also depicted these valves in the wrong position; (4) Valves MO 2(3)-2301-48 and MO 2(3)-2301-49 were stroke time tested in the accident direction as required by the ASME Code; however, the data were recorded in error on the data sheets, which indicated that the valves were not tested in the accident direction; (5) there were no specified closing times for Valves MO 2(3)-2301-15, and MO 2(3)-2301-49 in the HPCI design basis document; and (6) Valve MO 2(3)-2301-15 was included in the IST program beginning in February 1996 even though it appeared that it should have always been tested in accordance with ASME, Section XI and TS 3.0.D, and constitutes an additional example of Deficiency 50-237(249)/96201-17.

The licensee performed a 10 CFR 50.59 evaluation and concluded that the current positions of the valves were acceptable. General Electric, in a letter to the licensee dated November 4, 1996, indicated that the current standby positions of Valves MO 2(3)-2301-15, -48, and -49 were acceptable; however, the current alignment of these valves slightly reduced the reliability of the HPCI system by requiring three additional HPCI system valves to change position during HPCI initiation. As discussed in Section 5.1.3, the licensee was considering returning these valves to their original standby alignment because of the effects on Unit 2, 250 Vdc battery duty cycle loading.

The overload protection of the HPCI oil tank heater was not depicted on schematic Diagrams 12E-2532, Revision AD, and 12E-3532, Revision U, even though the overload elements were actually installed and were shown in the wiring diagram. The schematic drawings were critical control room drawings. The licensee indicated that an engineering request (ER) would be issued to track the corrective actions. This constitutes an additional example of Deficiency 50-237(249)/96201-22.

5.1.5.2 HPCI System Setpoint Deficiencies

Some design assumptions in setpoint Calculation NED-I-EIC-0111, Revision 2, " High Pressure Coolant Injection (HPCI) Steam Line High Flow Isolation Setpoint Error Analysis at Normal Operating and Accident Conditions," were not supported. The environmental effects on errors were not explicitly included, but were assumed to have been included in the generic error figure provided by the vendor. No documentation supported this assumption. Similar findings were identified in setpoint Calculations NED-I-EIC-110, Revision 1, "High Pressure Coolant Injection Low Reactor Pressure Isolation Error and Setpoint Analysis," and NED-I-EIC-108, Revision 2, "High Pressure Coolant Injection Turbine and Pump Area Temperature Switch Setpoint Error Analysis at Normal Operating Conditions." These unsupported assumptions constitute additional examples of Deficiency 50-237(249)/96201-22. Additionally, Calculation NED-I-EIC-011 for the low reactor pressure isolation setpoint used a setpoint of 80 psig rather than the appropriate setpoint of 100 psig.

As a result of reviewing the UFSAR, the HPCI DBD, an LER, initial licensed operator training documents, system training documents, and the Individual Plant Evaluation (IPE), the team identified that UFSAR, Section 6.3.2.3.3.4, and the DBD, Section 4.1.4.7, indicated that the setpoint for isolation of the steam supply to the HPCI turbine was 100 psig. However, the training material, IPE, and LER 50-237/94024 indicated that this setpoint was 80 psig or lower. The purpose of the low pressure isolation setpoint is to isolate the HPCI turbine before the turbine rotor stalls in order to prevent bowing of the turbine shaft. The licensee informed the team that a pending change to the UFSAR, dated August 22, 1996, would revise the UFSAR value for the setpoint from 100 psig to 80 psig.

The licensee indicated that the actual isolation setpoint in the plant was approximately 65 to 70 psig. At the end of the inspection, the licensee was still reviewing the affected documents for any changes warranted, but had concluded that the actual setpoint should be changed to 100 psig. This problem was tracked in a PIF and an ER was initiated to revise the setpoint calculation to use the correct process setpoint value of 100 psig. The

Dresden Station instrument surveillance procedures would be updated in accordance with the setpoint change control process. The licensee also prepared an OE which concluded that the HPCI system will be able to perform its safety-related function with the isolation setpoint switches at their current value.

The 10 CFR 50.59 evaluation supporting the pending UFSAR change to revise the setpoint from the specified 100 psig to 80 psig was inadequate in that it only considered this change as a clarification and an editorial correction without accounting for the possible impact on HPCI turbine operability. The failure to perform an adequate 10 CFR 50.59 evaluation represents an additional example of Deficiency 50-237(249)/96201-13.

5.1.5.3 HPCI Modification Deficiencies

The licensee implemented a modification to replace the circuit breaker associated with the Unit 2 HPCI GSLO condenser hotwell drain pump motor. The breaker was a 35 A Westinghouse Type FA, which had to be replaced because of a broken handle. Since the FA breaker was no longer available, the replacement breaker selected was a 30 A Westinghouse Type HFD breaker.

Calculation DR-E-96-0040, Revision 0, March 12, 1996, which was performed to determine the acceptability of the breaker, included a coordination diagram. The team identified several inconsistencies with the coordination diagram, including the determination that the motor thermal damage point had not been taken into account. When the thermal damage point is properly accounted for, the replacement breaker did not appear to provide adequate motor protection.

The characteristics for the breaker being replaced (Type FA) were not included in the calculation, which precluded the verification of the protective margin of the replacement breaker in comparison with the original breaker. Thus, it was not possible to determine whether a new failure mode had been created.

The team identified other inconsistencies, such as: (1) the motor accelerating characteristic neglected to consider voltages outside the 100 percent rating; (2) the short-circuit current at the motor terminals was not shown; and (3) the maximum continuous voltage rating to the HFD breaker was inadequate for the maximum battery equalizing voltage of 271.2 Vdc.

The team reviewed the licensee's response and identified that: (1) the licensee failed to demonstrate that the replacement breaker was adequate for providing proper motor protection because the breaker trip band of 10-19 seconds is an uncertainty band, and tripping at 10 seconds may not occur (typically, an appropriate breaker would provide margin over the maximum expected trip time to ensure that tripping would occur before motor thermal damage); and (2) the licensee's response was incomplete because the licensee did not evaluate the motor accelerating times at the expected limits of source voltages. The adequacy of the replacement breaker to perform its safety function is unresolved pending further licensee and NRC review (Unresolved Item 50-237(249)/96201-24).

Exempt Changes (i.e., minor changes) E12-2-96-216 (Unit 2) and E12-3-95-257 (Unit 3) replaced the existing HPCI system impulse trap with an AccuFlow condensate controller. The purpose of the steam trap was to drain condensate collected in the HPCI steam supply line upstream of the Valves MO 2(3)-2301-3. The Unit 2 change was implemented in May 1996 and the Unit 3 change was implemented in November 1995. The AccuFlow condensate controller is a special type of orifice that allows for a high pressure drop. The purpose for the change was to prevent nuisance alarms in the main control room and opening of the trap bypass valve on high level, which was causing accelerated piping corrosion. Opening of the bypass valve was caused, in part, by a prior modification that used a higher collection/drain point, which reduced the available drain pot volume. The previous modification attempted to reduce the potential for steam trap fouling. Also, the use of the impulse trap may not have been suitable for the intended application because adequate pressure may not have been available to open the steam trap and drain condensate, and would result in high level in the drain pot and opening of the trap bypass valve. The alternative modification of restoring the original drain point and adding a strainer and J-trap was rejected because of its higher cost.

Before the replacement of the steam trap with the orifice, the condensate/steam mixture was drained only when conditions required condensate removal. The piping downstream of the trap was not pressurized and only had flow through it when the trap or the bypass valve opened. After the orifice installation, a flow path was established that provided a constant flow of approximately 0.2 percent of rated HPCI steam flow to the main condenser in the standby mode and to the torus during HPCI operation. This caused the piping downstream of the orifice to become constantly pressurized.

Also, before the installation of the orifice, the pressurized piping was limited primarily to the HPCI room because the impulse trap would normally be closed. In the HPCI room, room temperature sensors isolate the HPCI steam supply line in the event of a line break or leak. After the change, the piping downstream of the orifice was pressurized even when the HPCI turbine was not operating. In addition, this piping extended into areas of the reactor and turbine buildings, which were not monitored by the HPCI room temperature sensors. The downstream piping has failed multiple times and the condition of the remaining piping has not been fully investigated. The failures were attributed to flow-accelerated corrosion. During the inspection, there was another leak in the Unit 3 downstream piping in the reactor building. The licensee estimated that approximately 30 failures have occurred in Unit 2 since 1984 and 20 failures in Unit 3 since 1986.

The licensee stated that the misapplication of the impulse trap caused the opening of Valve AO-2(3)-2301-31 (steam trap bypass valve), resulting in water slugs, at reactor pressure, passing through the drain line and into the main condenser. This condition caused water hammers and contributed to flow-accelerated corrosion of the drain line piping. The licensee stated that the installation of the orifice prevented the cycling of the bypass valve, minimized water hammers, and reduced piping corrosion in the main line and the drain line; therefore, the probability of a steam break inside the turbine building was reduced by the installation of the orifice.

Additionally, the licensee provided the following information: (1) The HPCI steam supply and associated drain piping was designed and installed as safety-related piping, and was seismically designed. The piping was qualified to 1250 psig. The orifice significantly reduced the pressure in the piping, and the stresses in the piping were well below that qualified by the design; (2) The orifice reduced the steam pressure from the HPCI steam supply from 1000 psi to a significantly lower pressure, causing condensation; (3) There were no functional changes to the system because the primary function of the drain piping to the torus was to provide for a condensate/steam pathway during HPCI operation. This flowpath was inside the secondary containment boundary; (4) Line breaks inside and outside primary containment were not assumed to occur simultaneously; therefore, a line break outside primary containment was not assumed to occur simultaneously with the design basis accident. Multiple pipe breaks would be only considered if the initial break outside primary containment resulted in the failure of other pipes outside primary containment because of pipe whip; (5) Nondestructive examination (NDE) of piping that was not replaced was not performed because this piping was scheduled to be replaced. The replacement of the drain line was scheduled for the D2R15 and D3R14 refueling outages.

The team evaluated the licensee's preliminary response and identified the following weaknesses:

- The licensee did not evaluate the effects of creating an unanalyzed condition when piping with known flow accelerated corrosion problems was continually subjected to pressure during the standby mode and operation of the HPCI turbine.

- The licensee did not evaluate the effects of drain line piping leaks that would not be monitored by the HPCI isolation system.

- Isoenthalpic expansion of the saturated/wet steam across the orifice would result in superheated steam and not condensation, as indicated in the licensee's response.

- Although the 10 CFR 50.59 evaluation correctly assessed the effects of the problems associated with the previous impulse trap and bypass valve operation, it did not address the effect of continued corrosion, which could have been a contributing factor in the piping failures in the reactor and turbine buildings after the implementation of the change. In addition, the evaluation compared the orifice installation to the existing steam trap design rather than the original design that was described in the UFSAR.

- The licensee's response indicated that the pathway between the orifice and torus was within the secondary containment boundary. A significant portion of the pressurized piping was located in the turbine building.

- The licensee's position that the stresses in the piping were well below that qualified in the design may not be valid because the piping was known to be degraded and portions of the piping have not been examined.

Section 6.3.2.3.2 of the UFSAR describes the cyclic function of the steam trap and the trap's purpose to eliminate water slug buildup to permit rapid turbine start. Section 6.3.2.3.3.2 describes the capability to automatically isolate the steam supply to the HPCI turbine and initiate an alarm to the control room operator on the basis of high HPCI room temperature. The failure to properly evaluate the HPCI steam trap replacement with an orifice represents a failure to comply with 10 CFR 50.59, and constitutes an additional example of Deficiency 50-237(249)/96201-13.

The reliability of the HPCI steam trap has been a long-standing problem. Instead of addressing the root cause of the problem, which was an inappropriately selected condensate drain system (trap, strainer, bypass valve, etc.), the licensee continued to repair the symptom of the problem. Approximately 50 piping repairs were performed. The decision to replace the trap with an orifice was partially made on the basis of a construction cost comparison with a proposed modification to restore the trap to the original location on the drain line. As previously discussed, the change was not adequately evaluated for suitability, given the existing piping condition. At least two piping failures occurred after the change was implemented. The licensee planned to replace the existing piping with the piping made of a material more suitable for prevention of corrosion; however, this corrective action addressed only the symptom of the problem. Additionally, the proposed schedule for the replacement of the piping was developed on the basis of the refueling outage schedule and not on a detailed examination of the piping condition.

A September 22, 1994, ComEd letter to the NRC, related to a Notice of Violation for NRC Inspection Report 50-237(249)/94-14, stated that "A change to the Dresden FSAR will be submitted by 12/31/94 to clarify that continued operation of the HPCI system is dependent upon AC electrical components." The team noted that the UFSAR had not been updated as committed in the letter. The licensee identified the UFSAR discrepancy during its August 1996, UFSAR reviews and initiated a UFSAR change. The failure to update the UFSAR is contrary to 10 CFR 50.71(e)(4), and constitutes an additional example of Deficiency 50-237(249)/96201-23.

During a review of the design bases of the HPCI room cooler, the team identified that the licensee had modified the original room cooler design to not rely on a safety-related source of cooling water to the room cooler and only rely on the fan portion of the room cooler for air circulation under design bases accident conditions. This modification had been reviewed and approved by the NRC staff. The team noted that a limiting component for HPCI operation was the gland seal condensing equipment because it was not environmentally qualified. Therefore, higher room temperatures could cause the gland seal condenser equipment to fail. The licensee acknowledged the reduced design margins caused by the elimination of a safety-related source of cooling water to the room cooler and indicated the intention to pursue environmental qualification of the gland seal condenser equipment.

5.1.6 Bases for Technical Specification Surveillance Testing Acceptance Criteria

The team reviewed the TS surveillance requirements for the emergency core cooling system (ECCS), which includes the CS, HPCI, and LPCI pumps, and identified that there were no retrievable system hydraulic calculations that provided the bases for the TS surveillance acceptance criteria to ensure that test conditions suitably reflected accident conditions. The TS surveillance test performance acceptance criteria for the ECCS pump flow values did not provide any allowances for instrument error, and there were no preoperational test data for some ECCS pumps that demonstrated the ability of these pumps to perform their intended safety functions.

The licensee performed preliminary hydraulic calculations for all ECCS systems, but did not include the CCSW system. On the basis of these preliminary calculations, the licensee concluded that the results of HPCI, CS, and LPCI pump testing demonstrated that these systems can perform their safety-related functions. However, the licensee also identified several examples in which design margins were reduced, including:

- Core Spray Pumps 3A and 2B were predicted to have flow rates slightly below 5650 gpm used in the PCT analysis. A PIF was initiated.

- The lower TS limit associated with the HPCI surveillance of 1200 psig could be insufficient to demonstrate compliance with the design basis. A PIF was initiated.

- The results of the Unit 3 HPCI pump surveillance tests indicated measurable pump degradation, while still acceptable.

Additionally, the licensee stated in a letter to the NRC, dated November 6, 1996, that the Dresden Station 10 CFR 50.46 analysis did not include allowances for the instrument uncertainty, but they planned to address the effects of instrument uncertainty by March 1997.

The results of these preliminary calculations indicated that with the existing low margins in pump performance, instrument errors, data nonconservatisms, and pump degradation, system performance could be impacted:

- For Unit 3, the licensee developed an analysis that depicted HPCI pump flow as a function of reactor pressure. This analysis predicted that the HPCI pump can deliver a flow of 5000 gpm against a reactor pressure of approximately 1180 psig. The 10 CFR 50.46 analysis assumed that for this flow the reactor pressure will be 1150 psig. Therefore, the available margin is only 30 psid (2.5 percent).

- For the CS system, the predicted combined flow rate was 11,380 gpm for the Unit 3 and 11,400 gpm for Unit 2. The limiting PCT analysis assumed, that at 0 psig reactor pressure, the combined CS flow will be 11,300 gpm. Therefore, the available margin is only 80 gpm, or 0.7 percent for Unit 3 and 100 gpm or 0.9 percent for Unit 2.

- These performance analyses were developed almost exclusively on the basis of test data from the preoperational tests, IST surveillance tests, and MOV tests, which in some cases, involved multiple instruments with various accuracies. As discussed in Section 4.6.2.2, the licensee identified that they had failed to meet ASME Code requirements for calibration error and accuracy requirements for indication instrumentation.

The licensee acknowledged the need to account for instrument error, but as of the end of the inspection, had not done so either in testing or the latest 10 CFR Part 50.46 analysis.

The need to consider instrument inaccuracy will remain unresolved pending further NRC review (Unresolved Item 50-237(249)/96201-25).

5.1.7 Licensee Self-Assessment of Design Control

The team identified that ComEd engineering Procedure NEP 12-02, Revision 3, "Preparation, Review, and Approval of Calculations," did not provide for the adequate control of calculations. Procedure NEP 12-02 stated in a highlighted note that "Calculations are not 'configuration managed' documents and are not automatically updated when plant conditions, design basis, or other conditions change. However, as a precaution all assumptions and design inputs must be verified because of this fact before using for another application." This note indicated the degree to which ComEd management had determined that calculations did not need to be controlled. This note clearly described management expectations and recognition of the lack of control over design calculations on a corporate level.

On the basis of the team's findings related to the control of design calculations (i.e., calculations identified to be out of date or not revised), from October 12-28, 1996, the licensee performed an evaluation of 25 of the 125 Vdc system calculations, including a review of nine implementing procedures. The licensee documented the assessment in a report "Calculation Design Control Assessment," approved on November 5, 1996. The assessment identified findings that were similar to the findings that the team identified. The licensee's assessment documented that: (1) Procedure NEP 12-02, assumes significant knowledge of the calculation history in order to determine whether other calculations need to be revised; (2) duplicate and superseded calculations were identified; (3) calculations used design inputs from previous revisions of calculations of record; (4) there was knowledge of the superseded calculations but since there was no impact on the conclusions, these calculations were not revised; and (5) calculations were not sufficiently cross-referenced.

The licensee acknowledged that the team's findings in the area of design control revealed weaknesses in the design process and governing procedure. They also noted that ComEd recognized the importance of calculations in 1994 and had been in the process of bringing design engineering to each facility since 1995. Because of the team's findings involving the current state of design basis calculations, the licensee initiated a PIF on November 6, 1996.

Several actions were planned by the licensee to address the concerns related to the current status of design control at Dresden Station. These actions are addressed in a November 8, 1996, letter to the NRC Region III Administrator. The letter specified actions that would be taken related to engineering activities for the Dresden Station facility. These actions included: (1) the establishment of an "engineering assurance group" to perform reviews of engineering work products such as new modifications and associated calculations, operability evaluations, and 10 CFR 50.59 evaluations; (2) provide specific guidance on actions to take when design bases issues are identified; (3) revise procedures by the end of November 1996 to provide clearer guidance on the review and updating of calculations, clearer expectations on control, retrieval, and configuration of calculations, and a reconstitution of calculations or the design bases for areas affected by any new modification; (4) perform an initial screening of key safety systems that were risk significant to determine conformance to the design bases; and (5) perform design audits of GE and selected A/Es, starting with Sargent & Lundy. The NRC confirmed these short-term actions in a Confirmatory Action Letter to the Dresden Station site vice president, dated November 21, 1996.

In addition, the licensee planned to conduct several other actions over the next few years. These activities included: (1) validate or reconstitute the design bases and critical calculations for risk significant systems over the next 2 years (including calculations to support functional testing); (2) perform a complete review of the UFSAR against the design bases documents; and (3) revise and update existing design bases documents for the risk significant systems over the next 2 years.

A letter from T. Maiman, ComEd, to the NRC Region III Administrator, dated November 12, 1996, stated that a number of additional initiatives had been completed or were planned for all ComEd facilities. These included: (1) validate UFSAR information for at least two systems against operating and surveillance procedures; (2) provide oversight of operability and safety evaluations; (3) provide additional support of the action request screening program; (4) review TS interpretations; (5) review safety evaluations for partially implemented modifications; (6) conduct safety system functional inspections; (7) review IST programs against design bases; (8) perform effectiveness reviews of Plant Operations Review Committee; (9) establish engineering assurance groups; (10) revise engineering procedures to address potential design bases discrepancies; (11) audit the major engineering contractors; and (12) define and reconstitute critical design calculations (ongoing efforts to validate or reconstitute critical design calculations supporting operations or modifications). Additionally, plans were being developed to upgrade the quality and access to design information in conjunction with ComEd's efforts related to the NRC's 10 CFR 50.54(f) letter, dated October 9, 1996, on the adequacy and availability of design bases information.

5.2 Resolution of Identified Deficiencies

The team reviewed the resolution of several identified deficiencies to determine whether the actions were completed and would prevent recurrence, finding that the licensee failed to adequately resolve a number of issues which, in some cases, existed for several years. The initiation of PIFs was sometimes untimely as licensee personnel attempted to resolve the matter or locate pertinent documentation. The lack of clear guidance in procedures for engineering issues also contributed to the untimely initiation of PIFs.

5.2.1 DC Battery Charger Seismic Mounting

A vulnerability existed in the configuration of the 125 Vdc and 250 Vdc systems because several battery chargers were not seismically mounted. The team postulated that a failure of a charger (i.e., high voltage output or internal short circuit) during a seismic event may degrade redundant dc system components. Also, the licensee did not consider the effects of failure modes, such as high output voltage, that may render inoperable critical control relays on dc logic circuits.

The original 125 Vdc and 250 Vdc battery chargers supplied by General Electric were considered nonsafety-related, and were installed and cables routed as nonsafety-related devices. For the present configuration, the 125 Vdc system Battery Chargers 2, 2A, 3, and 3A were procured in 1986 and installed as safety-related Class 1E components; however, the 480 Vac power feeds to the chargers did not meet Class 1E cable separation requirements and the Unit 3, 125 Vdc battery charger was installed with minimal base anchorage, which was inconsistent with seismic mounting requirements. The 250 Vdc system Battery Chargers 2, 3, and 2/3 were also procured in 1986 as safety-related Class 1E components. However, the 480 Vac power feeds to the chargers did not meet cable separation requirements, and the chargers were installed with minimal base anchorage, which was inconsistent with seismic mounting requirements.

The licensee was aware of this issue for several years. In October 1991, the licensee identified that the battery chargers were not properly mounted, but this issue was assigned a low priority for resolution. Design change packages were initiated to resolve the anchorage problem for the chargers, but were subsequently cancelled. From 1991 to the present, the licensee continued to evaluate the classification of the chargers (sometimes concluding the chargers were safety-related and sometimes concluding the chargers were nonsafety-related). Licensee evaluations occurred in March, July through August 1992, fall of 1994, and July 1995. The July 1992 evaluation by a licensee contractor concluded that the chargers would not tip over or impact other equipment. However, none of the evaluations assessed potential internal charger component failures that could cause high voltages on the busses and potentially cause the busses to become inoperable. As a result, no actions were taken to properly mount the affected chargers or to fully evaluate potential failure modes.

On October 11, 1996, the licensee initiated a PIF to document this concern, and initiated plans to provide seismic anchorage for the affected chargers during the next system maintenance window. Failure to implement corrective actions is contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion XVI, and constitutes an additional example of Deficiency 50-237(249)/96201-14.

5.2.2 Vulnerability Assessment Team (VAT) Open Items

The licensee performed a "Vulnerability Assessment" of selected systems and vital components from April to July 1992, to identify vulnerabilities and determine whether timely corrective actions were being taken. The licensee identified 76 vulnerabilities. Most of the 76 vulnerabilities had been closed with 13 items remaining open (4 were scheduled for closure by the end of 1996 and 9 were to be closed during future refueling outages). However, two significant discrepancies were identified in which the vulnerabilities were closed without any actions actually having been taken to address the vulnerability.

The team requested the documentation of the closure of VAT Items 24 and 25 which were related to the standby liquid control (SBLC) system. The licensee initially responded that Item 24 had been closed appropriately. Upon further review of the closure documentation for VAT Item 25, the licensee determined that neither Item 24 nor Item 25 had been closed appropriately. The team determined the following:

- Items 24 and 25 were related to the adequacy of the squib valve circuits to fire successfully. The SBLC squib valves are explosive valves, that upon receiving current, fire and open to provide a flow path to initiate the SBLC system and deliver a concentrated boron solution into the reactor vessel. During the VAT reviews, the licensee identified that under certain degraded voltage conditions there may not be sufficient current available to fire the squib valves. In addition, the licensee identified that the associated control transformer could fail after the squib valves were fired because of potential short circuits and, therefore, would cause a loss of power to the SBLC pumps. The licensee considered both vulnerabilities closed on the basis of the resolution of another SBLC system issue related to resistors used to regulate the current to the squib valves. However, the resolution of the resistor issue did not resolve Items 24 and 25.

- Although the licensee questioned the adequacy of the closure of VAT Item 25 as early as October 28, 1996, it was only after questioning by the team that a PIF was initiated on November 7, 1996, related to the improper closure of the VAT item. Between October 28 and November 5, the licensee attempted to retrieve documents supporting resolution of the VAT issues, but none were found. A PIF was not initiated during this period. The first PIF initiated on November 5, 1996, was related to the potential insufficient current to fire the squib valves. Only after discussions with the team did the licensee initiate another PIF on November 7, 1996, to evaluate the potential to damage the control transformer as the result of squib valve firing.

The licensee concluded that the existing circuits and components in the SBLC system were operable on the basis of the following: (1) The manufacturer of squib valve indicated that under degraded current conditions, the squib valves would still fire, although slightly slower than under minimum current conditions. The delay of firing would be on the order of milliseconds, while SBLC pump start is on the order of seconds; therefore, there would be no significant impact on SBLC operation; (2) With an existing unmonitored ground in the firing circuit, squib valve firing could short to ground, bypass the fuses, and cause a failure of the control power transformer resulting in stopping of the SBLC pump. The licensee tested the Unit 2 firing circuit and detected no grounds. The licensee will periodically test for grounds.

The licensee indicated that it planned to review the other VAT items for appropriate technical closure or closure plan, and was continuing to evaluate actions to provide additional margin to ensure adequate firing current and also ensure adequate performance of the control transformer. The failure to resolve the SBLC vulnerabilities identified by the VAT in 1992 constitutes an additional example of Deficiency 50-237(249)/96201-14.

5.2.3 Commitments

Licensee Event Report 2-89-029, Supplement 4, "Elevated HPCI Discharge Piping Temperature Due to Reactor Feedwater System Back Leakage," documents three Unit 2 and 3 events, which occurred in 1989 and 1990, involving the backleakage of reactor feedwater through a number of HPCI valves while the HPCI system was in the standby and testing modes. As a result of these events, the licensee implemented extensive corrective actions. One of the corrective actions involved the pressure testing (seat leakage testing) of Valves MO 2(3)-2301-8, -9, and -10 every refueling outage. Contrary to this commitment, Valves MO 3-2301-8, -9, and -10 were not pressure tested during the previous Unit 3 refueling outage, D3R13. The licensee stated the commitment was not implemented because it had not been entered into the nuclear tracking system. This constitutes an additional example of Deficiency 50-237(249)/96201-14.

Two additional missed commitments are discussed in other sections of this inspection report: (1) failure to incorporate an aging factor in the sizing calculation for the 250 Vdc battery (Section 5.1.3.1); and (2) failure to update the UFSAR to reflect the need for ac power for the HPCI room cooler (Section 5.1.5.3).

5.2.4 Initiation of Problem Identification Forms

During the inspection, the team identified that the initiation of PIFs for several engineering issues was untimely. While engineering personnel were often aware of an issue, they did not promptly initiate PIFs or only initiated PIFs after discussions with the team. Some of the more significant examples included: not initiating a PIF until discussions with the team on deficiencies in the CCSW calculations pertaining to the maintenance of the design bases LPCI heat exchanger differential pressure (Section 5.1.1.1); the initiation of a PIF after a week of attempting to find additional documents associated with the improper closure of issues involving the SBLC system (Section 5.2.2); and not initiating a PIF until discussions with the team related to the adequacy of station battery service tests (Section 4.6.3).

The team evaluated the guidance provided in Procedure DAP 02-27, Revision 5, "The Integrated Reporting Process (IRP)," regarding the threshold to initiate a PIF for engineering design issues. The team noted that Attachment D to Procedure DAP 02-27, "Station Reporting Process Thresholds," did not provide specific examples of licensing and design bases engineering design issues. The licensee agreed that additional guidance would be beneficial and provided a written response that indicated that Procedure DAP 02-27 would be revised to clarify the issues that require the initiation of a PIF.

5.2.5 LPCI/CCSW System Self-Assessment

The team's review of the LPCI and CCSW systems independently verified some of the issues identified by the licensee's self-assessment of the LPCI and CCSW systems. There were also issues identified by the team that were not identified by the licensee's self-assessment, or if identified, the full significance was not assessed.

Both the licensee's self-assessment and the team identified the absence of the design basis $NPSH_A$ calculations. However, the self-assessment did not identify the nonconservative assumptions in the $NPSH_A$ calculations discussed in Section 5.1.1.1 of this report. Also the self-assessment did not appear to question the ability of the ECCS to perform its safety function with deficient $NPSH_A$.

The team identified issues that were not identified by the licensee's self-assessment team, which included: (1) the lack of a technical basis for the TS surveillance requirements; (2)

the ability of the CCSW system to perform its safety-related function under the design basis condition; (3) the lack of a design basis for the control room chiller; and (4) not including macrofouling in the LPCI heat exchanger tube plugging criteria.

5.3 Modifications, Engineering Evaluations, and Design Bases

The team reviewed various modifications, engineering evaluations, and system design bases, finding that some design bases calculations had not been performed, were no longer retrievable, or had weaknesses. These findings indicated a lack of engineering rigor and discipline in ensuring that design calculations and evaluations were thorough and complete.

5.3.1 4 Kv Protective Relay Settings

The licensee neither controlled calculations for the 4.16 Kv safety-related switchgear protective relaying nor had controlled calculations for the offsite source protective relaying. Relay setting cards were available, but most of these cards did not have supporting calculations to ensure proper fault protection.

The licensee's corporate engineering staff was responsible for the protective relaying for all plant systems from the offsite source to the 4.16 Kv busses and 4.16 Kv loads. The plant staff was responsible for systems at the 480 V or lower voltage level. The 480 V protection calculations were available, and appeared to include all requirements for properly controlled documents. The licensee indicated that the lack of setting calculations would be evaluated consistent with the licensee's commitments for screening key design parameters against system calculations, as discussed in Section 5.1.7.

5.3.2 Backfeeding Through Main Transformers While Shutdown

As early as 1986, offsite power while shutdown could be provided by backfeeding through the main step up transformer; however, no calculations existed to evaluate the acceptability of voltages to busses through the backfeed arrangement. When the licensee was preparing to implement a modification in 1994 to add protective relaying to the backfeed source, it performed a limited 10 CFR 50.59 evaluation. At the same time, Operating Procedure DOP 6100-21, Revision 0," Transformation of Unit Transformer TR-2(3) to a Unit Auxiliary Transformer (Loss of Off-Site Power Conditions Only)," was created for the normal use of backfeeding during shutdown conditions. Except for the protective relaying calculation, no additional calculations were performed to support the routine use of backfeeding. The licensee responded that a calculation would be performed for the use of the backfeed and a PIF was initiated. The failure to have appropriate calculation supporting plant operations is contrary to 10 CFR Part 50, Appendix B, Criterion III, Design Control, and constitutes an additional example of Deficiency 50-237(249)/96201-22.

5.3.3 Degraded Voltage Relay Setting Calculation

The setting of the degraded grid voltage protection allowed for up to 6 minutes of plant operation, as described in Section 8.3.1.7 of the UFSAR, to allow time for the operators to restore normal bus voltage. While the timer would be bypassed on a high drywell pressure or low-low reactor water level, for other situations, plant equipment would be operating at voltages that would be considerably less than acceptable analytical limits. The ac voltage calculations to determine the relay settings had the following apparent omissions and unsupported assumptions:

- These evaluations did not document the determination of acceptable voltage at the terminals of loads fed off the 208/120 Vac transformers. The licensee indicated that they had performed an extensive review of the required ESF 208/120 Vac transformer loads.

- The calculations did not consider the need to evaluate the ability of 480 V motors to accelerate their loads to full speed at the assumed 85 percent motor starting voltage. The licensee provided an analysis that showed only motor start capability but did not demonstrate that the motor accelerating torque was in all cases sufficient to achieve full speed without stalling.

- The effect of temperature of contactor and other coils apparently was not accounted for in the evaluation of acceptable voltage for the 120 Vac control circuits. The licensee's response on coil temperature failed to address the cases of re-energization of systems, which would result in coils being hot and thereby require higher voltages to operate. The licensee's response did not support its position that only a "few coils" would be energized before a LOCA event and failed to provide a proper basis for the dismissal of the temperature effect of "the few coils," as well as to properly identify these coils.

5.3.4 Technical Specification Interpretation for the Nitrogen Inerting System

Technical Specification (TS) Interpretation No. 22, dated June 2, 1995, addressed the TS requirement pertaining to the Containment Atmospheric Dilution and Purge System, TS 3.7.A.6. The TS requires the system to supply nitrogen to containment for atmospheric dilution if needed by post-LOCA conditions. The bases for TS 3.7.A.6 explains that this capability is required to maintain the oxygen-hydrogen mixture below the flammable limit.

Interpretation No. 22 stated that a General Electric (GE) evaluation concluded that 29 scfm of nitrogen flow is needed to provide the required containment dilution; however, the system can only supply nitrogen to the containment at 20 scfm. The interpretation also stated that the GE performance requirement of 29 scfm should not apply to Dresden Station because the system design and installation predated the GE evaluation. TS 3.7.A.6 has been in place since 1974, and the GE evaluation was transmitted to the licensee in 1991.

The Unit 2 nitrogen inerting system was upgraded during the 1996 refueling outage and is capable of supplying nitrogen at a rate that exceeds 29 scfm. The Unit 3 system has not been modified. At the time this problem was identified, Unit 3 was shutdown. The ability of the Unit 3 nitrogen inerting system to satisfy the requirements of TS 3.7.A.6 will remain unresolved pending further licensee and NRC review (Unresolved Item 50-237(249)/96201-26).

5.4 Temporary System Alterations

The licensee's Dresden Plan actions have not been fully effective in minimizing the number of temporary system alterations. The Dresden Plan identified the need to establish a process to manage temporary system alterations, walkdown BOP systems to identify unauthorized temporary system alterations, and discuss temporary system alterations at the plan of the day meeting. Procedure DAP 05-08, "Control of Temporary System Alterations," was established to govern the temporary system alteration process. The Dresden Plan actions for temporary system alterations were completed in 1995.

While conducting general plant tours, the team identified two unauthorized temporary system alterations. First, Unit 3 Uninterruptable Power Supply (UPS) Static Inverter Essential Service Panel 903-63A was being cooled by a portable, external fan which was plugged into an electrical outlet of a nearby panel. Failure of the UPS would result in power to the 120 Vac essential service bus being transferred to the alternate power supply via an automatic bus transfer device, which was subject to a single failure vulnerability. The AR tag attached to Panel 903-63A stated that the internal inverter logic board cooling fan does not always operate and when it does, it makes an abnormal noise. Apparently, this condition has existed since 1995.

Second, on October 1, 1996, the licensee installed a temporary portable heater by the 3A offgas recombiner to maintain an elevated ambient temperature in the area, and documented this in Table A-6, "Additional Heating Requirements," provided in Procedure DOS 0010-25, Revision 2, "Preparation for Cold Weather for Unit 3." This heater was being used as a long-term alteration to provide area heating to compensate for the plant heating boiler, which had not been operating reliably. In doing so, this bypassed the controls and reviews that would have occurred under the temporary system alteration process.

Additionally, while reviewing the circumstances associated with the Unit 2, 125 Vdc battery room temperature falling below 65°F, the team identified, through document reviews, one additional unauthorized temporary system alteration that occurred on January 19, 1996. An HVO operator found that the Unit 2, 125 Vdc battery room temperature was at 64°F and falling. The minimum allowable room temperature per the HVO tour sheet was 68°F, which prevents the battery electrolyte temperature from falling below its design temperature limit of 65°F. The battery room temperature decreased because the east turbine room ventilation system dampers had fully opened as discussed in detail in Section 4.2.3.2. The ventilation dampers were wired shut to prevent a further decrease in the battery room temperature; however, the licensee failed to authorize a temporary system alteration.

The licensee continued to rely on the use of temporary system alterations, some of which were unauthorized, to address material and design problems. At the end of the inspection, the licensee was evaluating these conditions. These examples were not processed as temporary system alterations in accordance with Procedure DAP 05-08, and as a result, safety evaluations were not performed. The failure to perform safety evaluations for these temporary system alterations constitutes an additional example of Deficiency 50-237(249)/96201-13.

5.5 Licensee Reviews of the Updated Final Safety Analysis Report

In April 1991, ComEd initiated a multi-site UFSAR Rebaseline Project. It involved three phases: (1) collect applicable documents; (2) perform document reviews, create a document library, and collect any additional documents; and (3) conduct an independent check of UFSAR sections, identify commitments, and perform rebaselining. Its key objectives were to: (1) ensure regulatory compliance; (2) accurately reflect changes; (3) provide a complete and accurate UFSAR; and (4) implement a standard for ComEd.

Rebaselining was defined as bringing the UFSAR into agreement with available information sources by applying a quality controlled process and by providing process traceability. The need for a rebaselining effort was identified because of errors in the original UFSAR and a wide variation in the quality of the USFAR update process. The rebaselined USFAR was submitted to the NRC under the 10 CFR 50.59 process, and became effective in January 1994. After completion of the rebaselined UFSAR project, there were approximately 50 significant open items, which were closed by early 1996. The team selected five of these for review and determined that they had been appropriately dispositioned.

The licensee initiated a review of Dresden Station operating and surveillance procedures in July 1996 to verify that the UFSAR was consistent with these procedures. The anticipated completion date of this effort was December 1996. The team selected 15 of the issues that the licensee had evaluated to be the most significant and determined that none represented operability issues and that corrective actions were initiated to correct the discrepancies.

The licensee performed accelerated reviews for the CS, HPCI, and 125 Vdc systems after the NRC identified that these systems would be reviewed during this inspection. The team's review of the findings revealed that the licensee had not identified some of the discrepancies that the team had identified. For example:

- Procedure DGA-03, Revision 4, "Loss of 250 Vdc Battery Chargers Concurrent with a Design Bases Accident," Step D.1.c, specified that the operator trip the HPCI auxiliary oil pump within 1.5 hours. This would preclude the HPCI pump from restarting automatically if it trips or isolates. However, the UFSAR, Section 6.3.3.1.3.2, states that "a later pressure buildup above the setpoint would automatically restart the turbine if a HPCI initiation signal were present" (refer to Section 4.2.1).

- The actual HPCI standby alignment of Valves MO 2(3)-2301-15, 48, and 49 (in accordance with Procedure DOS 2300-03, Revision 36, Checklist A and B) differed from the alignment as described in UFSAR, Figure 6.3-9A (refer to Section 5.1.5.1).

- UFSAR, Section 6.2.2.2, which describes the LPCI mode for containment cooling, stated that "the pressure on the tube side of the heat exchanger is maintained

20 psi above the pressure on the shell side to prevent shell side water leakage into the service water and subsequent discharge to the river." The team identified that Calculation ATD-0216 indicated only a 8.26 psid differential pressure across the heat exchanger. The inability to meet the specified differential pressure of 20 psid was not identified in the licensee's UFSAR review process (refer to Section 5.1.1.1).

The licensee's efforts to improve the quality of the original USFAR was a significant upgrade, and its plans to validate the UFSAR against operating and testing procedures should further improve the accuracy of the UFSAR. The team identified some discrepancies that the licensee had not identified. At the end of the inspection, the licensee was evaluating further plans to perform a 100-percent review of the UFSAR and design bases documents.

5.6 Engineering Initiatives and Programs

The team reviewed the effectiveness of licensee programs to decrease the backlog and improve configuration control management, and evaluated the significance of several backlog and configuration control issues. While some progress was being made in reducing the backlogs to manageable levels, there was still a considerable amount of work needed to be performed.

5.6.1 Modification Backlog

Before 1995, licensee engineering support was typically contracted to one or more offsite engineering firms. Dresden Station configuration control managers depended on the configuration control practices existing at each of the offsite engineering firms and also on the coordination of emergent work among the contracted firms. The backlog of engineering open items and configuration control of contracted and onsite engineering work had significantly degraded configuration control. The licensee recognized this problem and initiated a configuration management improvement initiative in August 1995, which addressed configuration control improvements in several areas. The team reviewed several problem areas that included:

- The licensee identified 239 modifications that were started, some more than 10 years ago, but never completed.

- Over 500 modifications were not depicted in drawings and other engineering documents. In some cases, proposed modifications were depicted on drawings but were never installed.

The licensee identified the majority of the modification-related problems and was implementing a program to resolve them. Additionally, the licensee corrected errors associated with 180 critical control room drawings.

The team evaluated potential safety concerns and the licensee's rigor in dispositioning the 239 modifications that were started, but never completed. In reviewing the 10 CFR 50.59 evaluations that had been performed for the partially installed modifications, the licensee indicated that 10 CFR 50.59 evaluations were not performed for four partial modifications involving ventilation systems. These modifications affected the control room's ability to maintain a positive pressure. The licensee's efforts during this inspection to close out these modifications revealed significant problems in ensuring that a positive pressure was maintained in the control room. This issue is discussed in detail in Section 4.6.4.1.

The updating of modification-related drawings and other engineering documents was a significant undertaking and involved the review of over 20,000 drawings. The process of revising drawings was transferred from the contracted, offsite engineering firms to an onsite licensee group, a move that accelerated the process and made the task more manageable. In October 1996, approximately 800 design packages were open, of which approximately 500 of these were old packages that were being corrected. In addition to updating modification-related drawings, the site drawing revision group processed approximately 500 requests per year to correct drawings to reflect the "as-built" configuration. Some of these corrected drawings contained erroneous information since the plant was licensed. To date, the "as-built" upgrading effort focused on mechanical drawings. An effort to walk-down electrical drawings was just beginning.

Of the 94 modifications scheduled for the 1996 Unit 2 refueling outage, only 6 were deferred and 3 had not been completed. Station procedures required post-modification document closeout within 90 days. Not reflected in the modification backlog were backlogged modifications associated with the station blackout (SBO) upgrade. The Unit 2 SBO upgrade installed in 1996 included 1800 design changes. Of these, 300 were still open. The Unit 3 SBO upgrade was scheduled to be installed in 1997 and will most likely increase the existing backlog.

The team reviewed a sample of cancelled modifications to determine whether the licensee had an adequate safety basis for cancelling these modifications. Design Change Packages (DCPs) 8900153, 8900417, 8900418, and 8900419 for the seismic mounting of safety-related battery chargers were cancelled inappropriately, in part, on the basis of an evaluation that concluded the chargers would not tip over or impact nearby equipment. However, the licensee failed to consider the potential for internal component damage that could cause high voltages on the busses (refer to Section 5.2.1).

The purpose of DCP 9300122 was to install an MOV actuator that was capable of delivering greater closing thrust than the actuator currently installed on Valves MO 2(3)-2301-15. These valves, as well as Valves MO 2(3)-2301-10 provide isolation between the HPCI system and outside of containment. In 1993 the licensee identified that the actuator for Valve MO 2-2301-15 was not capable of closing against the shutoff head of the HPCI pump. Calculations using the appropriate valve factor indicated that the valve would not open and close against worst-case differential pressure and degraded voltage conditions. The licensee assumed that these results were also applicable to Valve MO 3-2301-15. As compensatory actions, the licensee revised procedures to declare the HPCI system inoperable in the test mode and to trip the HPCI turbine if either Valves MO 2(3)-2301-10 or Valves MO 2(3)-2301-15 fail to close, when the HPCI system is operating in the pressure control mode and the HPCI pump suction supply auto-transfers.

The licensee's initial long-term solution was to install a larger MOV actuator; however, when the licensee walked down the HPCI system, it determined that the larger actuator would not fit in the existing configuration. The licensee determined that other options included rotating or moving the valve, extending the valve yoke, or changing the design basis. In July 1994 DCP 9300122 was cancelled and the issue was tracked by Plant Change Request 0326, which was intended to disposition all MOV upgrades under the Generic Letter (GL) 89-10 program. Rather than replace the existing actuator with a larger actuator, the licensee modified the actuator gearing and bypassed the torque switch in the closed direction. These modifications were accomplished under Design Changes P12-2-94-272 and P-12-3-94-288.

Licensee personnel indicated that even after the implementation of these modifications, the actuator for Valve MO 2-2301-15 was marginally sized and the actuator for Valve MO 3-2301-15 was undersized. The licensee also stated that there were no plans to change the actuators because the valves were nonsafety-related and therefore were removed from the scope of the GL 89-10 program. However, the team determined that the HPCI design basis document still indicated that the HPCI MOVs, including Valves MO 2(3)-2301-15, must close against HPCI pump discharge pressure.

The licensee's written response to the team's questions regarding DCP 9300122 indicated that this DCP was not necessary because the existing actuator configuration provided enough capability to perform its safety function with acceptable design margin. The same written response also indicated that DCP 9300122 was cancelled because it was a duplicate of Design Change P12-2-94-272. This information was inconsistent with the information previously discussed, and the licensee subsequently provided a revised response. This issue will remain unresolved pending NRC review of the acceptability of removing Valves MO 2(3)-2301-15 from the scope of the GL 89-10 program (Unresolved Item 50-237(249)/96201-27).

5.6.2 Setpoint Verification Program

As part of the configuration management improvement initiative, the licensee included a program to verify the basis for existing setpoints in safety-related plant systems. The program included the verification of system setpoint requirements and the capability of the installed instrumentation to initiate the required actions when the setpoint was reached. The licensee identified 76 setpoints in safety-related systems for which there was insufficient or no documented bases.

In transitioning to standard TS, the licensee was required to develop bases for setpoints that were being added to the TS. However, in keeping with NRC's TS upgrade policy, setpoints that were already included in the original TS could be transitioned to the new TS without additional justification. The licensee has been unable to reconstruct the bases for setpoints that were originally provided by the NSSS supplier for use in the original TS.

The development of the bases for the currently identified 76 safety-related setpoints were scheduled to be completed in 1999. In addition to the 76 setpoints with insufficient bases identified by the licensee, setpoints for several relief valves associated with the CS, LPCI, and HPCI systems had no apparent relation to design parameters. Also, the CS and HPCI setpoint error calculations had unsupported assumptions, which is discussed further in Sections 5.1.4.3 and 5.1.5.2. These were not included in the scope of setpoint verification program.

5.6.3 The Vendor Equipment Technical Information Program (VETIP)

The 1995 Dresden Configuration Management initiative included a program to upgrade VETIP. The licensee had committed to implement the recommendations contained in GL 90-03, "Relaxation of Staff Position in Generic Letter 83-28, Item 2.2, Part 2, 'Vendor Interface for Safety-Related Components.'" GL 90-03 primarily related to the frequency and extent of interface with equipment suppliers to maintain an up-to-date database of equipment information on site.

From 1992 until the end of 1995, a contractor was responsible for implementing the VETIP program at the site. During this period, there was minimal management oversight of the program. In August 1993, the site quality verification (SQV) department conducted a review of VETIP at Dresden Station to evaluate the status of control in accordance with Procedure DAP 2-10, Revision 4, "Control of Vendor Equipment Technical Information." On August 8, 1993, the licensee initiated Corrective Action Record (CAR) 12-93-047, which identified deficiencies with VETIP. CAR 12-93-047 identified that commitments made in response to NRC GL 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events," and GL 90-03 were not being met. These commitments were stated in the licensee's responses to NRC dated September 26, 1990 and July 18, 1991, and clarified in the licensee's memorandum dated December 5, 1991 (Deficiency 50-237(249)/96201-28). Additionally, the master-controlled copy of vendor manuals could not be located, and there was no index of records to indicate the number and location of controlled copies of vendor manuals.

A subsequent licensee assessment of the program in September 1993 concluded the activities being performed did comply with GL 90-03, although these activities could not be considered a viable vendor equipment technical information library because the manuals were not controlled and were not maintained current. A detailed VETIP recovery plan was initiated in 1994, but was not successful in addressing the overall programmatic issues.

In September 1995, a root cause investigation of the 1993 CAR was performed. The licensee determined that VETIP remained uncontrolled because of a lack of commitment to prior corrective action plans. The VETIP deficiencies included over 18,000 individual vendor publications located in drawers, shelves and boxes that had not been consolidated, and uncontrolled VETIP information was in general use. Additionally, the VETIP program was not capturing all available technical information. After these manuals were assembled and reviewed, the number of vendor manuals was reduced to approximately 4000. The remainder were identified as duplicates, superseded, or not applicable. The licensee planned to assemble these manuals into approximately 1200 binders.

In January 1996, the licensee addressed VETIP and established specific commitments to bring VETIP into conformance with industry standards. The licensee assembled a group in January 1996 to review and update the program manuals. Up to 15 persons have been assigned to VETIP throughout 1996. The group selected a total of 50 binders to update

with the latest vendor publications. The binders were selected on the basis of suggestions from system engineers and maintenance personnel. The first 50 VETIP binders were assembled ahead of schedule. The program goal was to assemble safety-related manuals by May 1997 and complete the assembly of all manuals by December 1998.
On September 11, 1996, the SQV department initiated CAR 12-96-080 because of deficiencies in the document control and availability of VETIP manuals that were referenced in work package procedures. Because of this finding, the licensee initiated an accelerated schedule to review, approve, and control all pre-1996 vendor manuals by May 1997. Licensee personnel advised the team that approximately 783 vendor publications remained to be placed into vendor binders. The licensee informed the team that its system engineers did not identify any significant issues as a result of reviewing the remaining 783 vendor publications. The licensee also advised the team that they were in the process of collecting all uncontrolled vendor manuals from the maintenance shops and revising procedures if needed.

5.6.4 Operating Experience

The team reviewed the site processing of 12 NRC Information Notices (IN) that were received in 1996. The IN processing backlog identified by NRC earlier in 1996 was reduced significantly from 90 to 18 open items. However, the processing and dissemination of information was not rigorous.

Procedure DAP-02-11, Revision 8, "Operating Experience Report Review," required the operating experience engineer (OPE) to screen incoming information for applicability, assign reviewers, and specify the level of review. No indication was on the review assignment sheets, Form 02-11B, indicating that the OPE made these assignments. The assignment sheets were completed by the individual assigned to review the notice. This same individual determined the level of review rather than the OPE. The team noted that IN 96-25, related to radiation hazards resulting from an incore probe over-withdrawn because of a faulty mechanism, was forwarded to maintenance organization for action. However, there was no request for review by the radiation protection or operations departments.

The team reviewed the completion and maintenance of licensee commitments related to five NRC INs, and an OE which specified followup actions. The team determined that 1 of the 6 internal commitments had not been appropriately implemented. This item involved dc system relays and potential overcurrent situations. The licensee grouped a number of related industry documents together (including the response to NRC IN 89-16, "Excessive Voltage Drop in DC Systems") and provided internal responses to the related issues in a memorandum dated May 24, 1989. In this memorandum, one of the licensee responses to an industry event committed to make procedure changes to ensure the evaluation of relay operating voltages if system modifications resulted in system voltage increases. The licensee was unable to demonstrate that the specific commitment to change the procedure was implemented. Current procedures reflected only general design guidance to maintain design bases for components, but did not reflect the specific issue related to the potential impact of increased system voltages on dc system relays. The licensee initiated a PIF documenting the failure to maintain the commitment to change the appropriate procedure.

5.7 NRC Inspection History

The inspection history documented both corporate and site engineering ineffectiveness in resolving issues without NRC involvement. A number of instances were identified that reflected untimely or ineffective corrective actions for identified issues (e.g., corner room steel and 4 Kv breaker issues). Similar issues were also identified by the team indicating a continued need for licensee management attention.

The inspection record also documented that UFSAR and licensing design bases commitments were not emphasized and engineers lacked sensitivity towards their application. In addition, the inspection record also documented inconsistencies and errors in the UFSAR that had not been identified in the rebaselining process. These were similar to issues identified by the team. The inspection record also documented instances of calculation weaknesses, including (1) errors, (2) improper methodology, and (3) unsupported or nonconservative assumptions. The individual instances did not result in system or component inoperability, but reflected weaknesses in the design process.

6.0 MANAGEMENT OVERSIGHT, CORRECTIVE ACTIONS, AND SELF-ASSESSMENT

The team conducted more than 100 formal interviews, observed numerous meetings, and reviewed relevant documents. The team also used the equipment and process issues identified in the operations, radiological protection, maintenance, testing, and engineering areas as a basis for evaluating management oversight, corrective action, and self-assessment effectiveness.

Corporate oversight and support for Dresden Station were improving, but the changes at the corporate level were less than a year old, and most new initiatives had not been fully implemented. A significant weakness in corporate support to Dresden Station was the failure of the corporate engineering organization to ensure the station's design calculations were controlled and maintained.

In the past 2 years, site management oversight was improved and a large number of managers and supervisors with broad nuclear experience were hired. Because of management, supervisory, and process changes, management expectations for the accomplishment of work were not understood in some cases. There was significant progress in addressing the objectives of the 1994 Dresden Plan, although some initiatives were ineffective and implementation of others was delayed. Licensee planning was improving, but plans did not extend beyond 1997.

Site managers and staff were addressing several long-standing obstacles to performance improvement. Management efforts to reinforce individual accountability for safety performance, and to improve the capabilities of station personnel, appeared to be effective in addressing these obstacles. The Dresden Station staff was not reluctant to bring safety issues to their manager's attention.

Weaknesses continued in identifying and resolving problems, although problem identification had generally improved in most areas. Licensee self-assessments documented substantive findings in some cases and the effectiveness of the site quality verification organization was improving; however, some licensee self-assessments were weak, particularly in engineering. The actions of the offsite review function, performance monitoring reports, and Plant Operations Review Committee activities served to independently assess performance, although weaknesses in some areas were not identified. Additionally, some corrective actions were ineffective, resulting in repetitive problems. The licensee had recognized weaknesses in root cause analyses and were addressing them. The team also identified weaknesses in implementing the corrective action process.

6.1 Corporate and Site Management Oversite and Support

6.1.1 Corporate Oversight and Support

Corporate oversight and support for Dresden Station were improving within ComEd's Nuclear Operations Division (NOD). Overall, the team found little evidence remaining of the lack of leadership, attention, and support from NOD that was noted in previous diagnostic evaluations of ComEd facilities. However, improvements at the corporate level were less than a year old and were in the early stages of development. Therefore, the team was unable to determine the extent to which NOD managers would be successful in sustaining support for the improvements necessary at Dresden Station. Some significant weaknesses remained to be resolved in providing effective corporate support for Dresden Station. For example, the corporate engineering organization failed to maintain and control the station's design calculations before to the recent transfer of these calculations to Dresden Station.

The most notable change at NOD was the new management team. In the past year, a new chief nuclear operations officer (CNOO) was hired from outside of ComEd and assigned accountability for the NOD. In addition, a new executive vice president for nuclear operations was named and given responsibility for interfacing with the Board of Directors and other ComEd Divisions. These realignments were motivated by corporate management's recognition of the need for ComEd to change its nuclear philosophies and practices.

One immediate action taken by the CNOO was to obtain increased operating and maintenance (O&M) funds for the nuclear facilities. The CNOO justified the increase by demonstrating the significant discrepancy between industry average O&M budgets for similar plants and the historical annual O&M expenditures for the ComEd nuclear facilities.

The NOD managers accepted the goal of accomplishing the corporate changes required to achieve a competitive position by the year 2001. A number of NOD-wide initiatives were being developed at the time of the inspection to solve long-standing problems across the older nuclear sites and to achieve potential economies of scale from integrating some functions across NOD's six nuclear facilities.

The new NOD vision was articulated in terms of safety, production, and cost, in decreasing order of emphasis, and success metrics were defined to evaluate progress. The safety performance goal across NOD was defined as an average systematic assessment of licensee performance score of 1.5. Production success was defined as an average capacity factor of 75 percent. The expectation was that costs will naturally decrease as performance improves. These goals were preliminarily incorporated into the draft 1997 Dresden Business Plan, but the Plan had not been finalized by the end of the inspection period. Further, the licensee had no approved long-range plan for Dresden Station to meet the NOD goals, although NOD initiatives to link the budget process to the goals and to specific performance improvement initiatives were being implemented.

In order to support the performance improvement initiatives required at Dresden Station, NOD managers intended to increase the Dresden Station O&M budget by about 10 percent over expected 1996 expenditures. Preliminary 1997 budget requests from Dresden Station managers were approximately 10 percent higher than the NOD target. However, the budgetary impact of the engineering initiatives that the licensee committed to at the end of the inspection were not considered when the budget requests were developed. Consequently, the team was unable to determine whether progress on other improvement initiatives would be reduced in order to address the engineering issues or whether NOD would further increase the commitment of 1997 funds to Dresden Station.

The results of interviews revealed that various alternative approaches to continued improvements were considered. For example, the option of entering a voluntary outage to address long-standing material condition deficiencies was discussed, but it was rejected in favor of continued operations and deferral of the planned improvements to outages over the next 2 or 3 years. The licensee provided two reasons for rejecting an extended outage. First, an acceptable return on the potential investment may not be realized before Dresden Station's operating licenses expire. Second, the Dresden Station staff could not yet plan and manage the large amount of work required during an extended outage.

One area in which the effects of the previous lack of corporate oversight and support were still evident was the inadequate control that corporate engineering had maintained over Dresden Station's design basis calculations. Numerous calculations of limited scope were allowed to proliferate. This eventually resulted in a situation in which the control of design inputs and outputs among calculations became onerous. Corporate engineers did not recognize that the quality of some calculations performed by ComEd's A/E was inadequate. Corporate engineering managers concluded that it was unnecessary to revise all affected calculations when changes were made to one, but rather that it was appropriate to rely on the experience of the engineering staff to determine when it was necessary to revise a calculation if a design input changed. This decision was institutionalized in a corporate engineering procedure that governed the conduct of engineering at Dresden Station, even after the design engineering function was moved to the site.

6.1.2 Station Improvement Initiatives

Management of performance improvement initiatives and overall management planning at Dresden Station has improved. A noteworthy accomplishment has been the establishment of a strong, broadly experienced management team within the past year. NOD and Station management have begun to approach improvement as a continuous process requiring integration, funding, and a commitment to quality. The licensee has made significant progress in addressing the objectives of the 1994 Dresden Plan, although adjustments in the implementation of specific Dresden Plan items have been required when actions were unsuccessful or new problems were identified. There have been delays in addressing some Dresden Plan initiatives, such as improvements in vendor technical manuals and the migration, evaluation and indexing of engineering calculations. Some completed Dresden Plan actions such as long-range planning and the control of temporary system alterations have been less than fully effective. Various management initiatives have not captured all the problems, particularly in engineering, and have not been successful in addressing a wide variety of recurring and long-standing problems.

One significant example of the results of a Dresden Plan action that was not accomplished in a timely manner involved design calculations. The Dresden Plan called for the development of the site engineering function and required an evaluation of design calculations to determine how they would be indexed and controlled at Dresden Station. However, calculation migration to the sites came under a corporate-wide initiative, and documentation showed that Dresden Station and Quad Cities Station were scheduled to be the last of the sites to complete the migration. Site managers were unaware of the serious flaws in the quality and configuration control of design basis calculations.

6.1.3 Communication of Management Expectations

Communication of management standards and expectations throughout all levels of the Dresden Station organization was improving. Communication of expectations from NOD to top managers at the site was clear and effective, as well as communication among the site vice president (SVP) and the department heads. Below the department head level, some management expectations were less well understood.

Interviews indicated that the NOD priorities of safety, production, and cost were meaningful to Dresden Station personnel at all levels of the organization. The team found no evidence of a reluctance among lower-level managers or bargaining unit employees to raise safety concerns to their supervisors and managers. Senior station managers, in particular, were generally perceived as both accessible and committed to resolving safety concerns.

Site management performance goals and standards also appeared to be well understood by lower-level managers and the staff. Global expectations such as accountability, strictly adhering to procedures, and teamwork were reinforced through multiple methods of communication, including all-site meetings held by the SVP, departmental standards' booklets and meetings, and the site daily newsletter. However, the team observed that communication of overall standards and expectations was notably less visible in the site design engineering organization than in other departments.

Communication of specific management expectations for performing work at the site was less effective. Dresden Station has undergone significant organizational change since 1994, and the changes created a lack of clarity in the communication of management expectations for the performance of specific work activities in several instances. In the past 2 years, the composition of Dresden Station's top- and mid-level managers, and first-line supervisors has changed substantially. Of a total staff of approximately 950, 147 managers retired, resigned, or were transferred out of their positions between June 1, 1994, and June 30, 1996. In the same period, 275 staff members were moved into management positions.

These changes were motivated by NOD's and the SVP's intention to improve the effectiveness of station leadership and to bring broader nuclear experience to the site. Of the 275 staff members who became supervisors and managers, 101 were hired from outside ComEd, 58 were transferred from other ComEd non-nuclear facilities, and 27 were transferred from other ComEd nuclear facilities. The remainder were Dresden Station personnel.

As a result of these changes, management expectations were not consistently communicated for some activities because many managers and supervisors were too new to their positions to fully understand current routine procedures in their work groups and had not yet determined how they expected specific activities to be performed. For example, in the radiation protection (RP) department, five new first-line supervisors were hired from outside of ComEd in the past year. Three of the five new first-line supervisors were unclear regarding their own and their managers' expectations for several activities.

In addition to the management and supervisory changes, processes and procedures for performing work were undergoing rapid change at the site. In some instances, management expectations regarding how the changes were to be implemented were not fully defined or communicated to the individuals responsible for implementing them. Licensee root cause analysis reports of events involving human performance deficiencies over the past 2 years described multiple instances of errors and delays caused by licensee staff being unaware of process and procedure changes. Although policy and procedural changes often were discussed in weekly departmental and shift meetings, the discussions were not formally documented in all departments, and staff members who were in training or absent from the meetings for other reasons did not receive the information routinely or in a timely manner.

6.2 Staffing Initiatives

6.2.1 Personnel Accountability

Dresden Station's human resources management reflected substantial improvement since the NRC's 1987 diagnostic evaluation. Processes and procedures for recruiting, screening, and selecting personnel were effective. Personnel job performance evaluations were being conducted for both managers and bargaining unit staff, and a new performance evaluation process was being developed at NOD to link compensation to performance.

Management's emphasis on individual accountability and use of discipline to reinforce it, as well as specific performance feedback about expectations, was described by the majority of interviewees as a significant departure from previous Dresden Station management styles. No evidence was identified by the team to indicate that the threat of disciplinary actions had created a chilling effect on employees' willingness to raise safety concerns; however, several interviewees reported that the new emphasis on individual accountability and the potential for disciplinary action resulted in some staff members' hesitancy to suggest work process enhancements, to take leadership roles in solving problems, or to document human errors and performance problems through the PIF process.

6.2.2 Management and Staff Relations

Management and staff relations were undergoing significant change at Dresden Station. The team noted several hundred local sidebar agreements to the ComEd Collective Bargaining Agreement that were entered into over the past 20 years, as well as undocumented work practices, which were developed on the basis of unique interpretations of the Agreement, that were institutionalized. Although management and the bargaining unit personnel have been successful in removing some of these sidebar agreements, removal of others will depend upon the outcome of upcoming contract negotiations.

One long-standing problem, which the licensee has addressed by changing past work practices, was maintenance skills weaknesses. In addition to providing additional training to the existing maintenance staff, the licensee was also in the process of hiring A-level mechanical maintenance staff from outside the ComEd system. In the past, the practice was for all A-level mechanics to be trained by ComEd and promoted from within. However, management determined that there was an immediate need for an available, larger cadre of qualified A-level mechanics. Therefore, it was impracticable to train and promote from within for these new positions. Other changes to past practices implemented by management included the formation of problem-solving teams that consisted of both managers and workers, the formation of specialized maintenance teams, the establishment of a new approach to limiting and distributing overtime, and the establishment of some flexibility in the assignment of work among job classifications.

6.2.3 Employee Concerns Program

Employee awareness of the Quality First Program was widespread at Dresden Station. Almost all interviewees reported that they would use the program, if necessary, but they also stated that any nuclear safety concerns would receive appropriate management attention through the normal management chain or the SVP's hotline. A few interviewees stated that a report to the Quality First Program would not remain confidential and could result in management reprisals, although the team found no evidence to support this perception.

6.3 Problem Identification and Corrective Actions

6.3.1 Problem Identification

The identification of problems affecting plant safety performance has improved; however, the team identified significant weaknesses that reduced the effectiveness of problem identification. Through independent review, the team identified that a number of problems were neither recognized nor assessed for significance. Therefore, these problems were not appropriately resolved in accordance with the established corrective action process. Some staff members, particularly in the maintenance and radiological protection organization, were reluctant to use the problem identification process. Design engineering's use of the process was extremely limited because its use did not appear to be encouraged. Procedural weaknesses also contributed to the limited implementation of the problem identification process within engineering.

The threshold for problem identification was low in most areas. Completing a PIF was the primary method for the staff to document problems. Over 5000 PIFs were written in 1995 and about as many had been written in the first three quarters of 1996. However, only about 2 percent of the reports were generated by the design engineering department. The team identified multiple examples of the failure of the engineering department to initiate PIFs or initiate PIFs in a timely manner. For example, the licensee closed uncorrected VAT items related to the SBLC system, but did not initiate a PIF until questioned by the team.

Notwithstanding the weaknesses in the engineering department, numerous examples of internal assessments and PIFs demonstrated a pattern of increasing sensitivity to material condition and work process problems. Although many problems identified by the team had been previously identified by the licensee, some other notable problems had not been recognized. For example, the licensee did not identify omissions and nonconservative assumptions in the 250 Vdc battery sizing calculation, which resulted in a significant change to the design load profile. From interviews with licensee workers and SQV department reviews, the team learned that the staff in some departments were reluctant to document problems involving human performance through the PIF process because of the perception that the identification of personnel errors would result in disciplinary action.

Some deficient conditions that had existed for years, in some cases, were not recognized by licensee personnel as problems requiring evaluation through the PIF process. These included: (1) operator workarounds, such as the feedwater three element control system being operated routinely in single element control; (2) unauthorized temporary system alterations, such as temporary cooling provided to a static inverter panel; and (3) automatic features of systems being controlled manually, such as the service water strainer backwash controller, which was operated in manual for a number of years.

The generic implications of problems were not recognized or were not considered in some areas. A Unit 2 battery room low temperature event in February 1996 was preceded by a similar problem in January 1996. These two events, as well as other battery room low temperature events, were not recognized as a trend by the licensee and were not escalated to Level 3 status so that a root cause analysis would be performed.

Interviews also indicated that licensee personnel were not certain when a problem should be identified by the PIF process or the Action Request (AR) process. Material condition deficiencies were identified by use of ARs. Unlike PIFs, most ARs were not trended, so that repetitive ARs may not have been evaluated for generic implications.

6.3.2 Problem Assessment

The team identified weaknesses relative to the licensee's processes for assessing problems and formulating corrective actions. The inability to correct some persistent problems was partially rooted in these process weaknesses, which included the categorization of some problems at a level that would not ensure appropriate management attention and a root cause investigation, as well as untrained personnel performing some root cause analyses resulting in the formulation of ineffective corrective actions. Management and increased SQV department involvement in these processes and the initiation of training for dedicated root cause analysts appeared to be addressing these weaknesses.

Levels 1, 2, and 3 PIFs were evaluated for root cause; however, the workload caused by the generation of thousands of PIFs resulted in a decision to raise the threshold at which problems would receive a root cause investigation. Although the team identified an instance in which Level 3 PIFs were inappropriately categorized as Level 4 PIFs, the team also observed that managers involved in PIF reviews elevated Level 4 PIFs to Level 3 when they judged that a root cause investigation was warranted even though it was not required by the procedure.

The licensee identified a number of weaknesses involving the root cause analyses of previously identified problems, and implemented actions to improve the quality of root cause determinations by designating dedicated root cause analysts who were or will be trained in analysis techniques, and will become leaders in root cause investigations. However, some root cause analyses were still being performed by untrained personnel. For example, none of the personnel leading the most recent Level 2 investigation in early 1996 of radioactive material control problems received this training.

Some licensee investigations of events inappropriately identified symptoms as root causes of the events. For example, the licensee's Level 2 trend investigation of foreign material exclusion (FME) problems, initiated because of a second event involving a rag entangled in a CCSW pump rotor assembly, determined that out of 9 investigations of similar past events, 5 had identified symptoms rather than root causes, resulting in ineffective corrective actions. Additionally, a licensee's corrective action audit concluded that in 7 of 12 problem investigation reports reviewed, the causal analyses were performed at an insufficient depth to identify root causes.

Notwithstanding these problems, managers and oversight groups were actively involved in reviewing and categorizing PIFs, as well as reviewing and approving root cause analyses, proposed corrective actions, and subsequent steps in the process. Reviews and approvals of these steps were performed by the SQV department, line managers, the Corrective Action Review Board (CARB) (a multi-disciplined team of senior supervisors representing department management), and, when appropriate, the Plant Operations Review Committee (PORC). CARB and PORC meetings attended by the team were professionally conducted with informed and questioning participants, and appeared to be improving the process. Because the problem assessment process had been in effect for only a short time, the team could not determine its overall effectiveness in reducing repetitive problems.

6.3.3 Problem Resolution

The licensee effectively resolved some long-standing or recurring problems, although both the licensee and the team identified weaknesses in corrective action effectiveness. As a result, a number of previously identified programmatic and hardware problems were not resolved. Multiple examples of long-standing problems that were not resolved are documented in Sections 3 through 5 of this report. Corrective action commitments were tracked and controlled to the desired completion date through the nuclear tracking system (NTS), the computerized station commitment tracking system, but without interim planning or effective oversight. Personnel continuity through all steps in the corrective action process and communication between those who investigated the problems and those who implemented the corrective actions were lacking. Corrective actions for complex problems involving several departments and large site populations were fragmented into narrowly focused tasks, which did not receive management ownership and oversight commensurate with the broad-based problems that they were intended to solve. Effectiveness reviews, while identifying problems in corrective action implementation, failed to produce timely and effective correction of some problems.

The timeliness of completion of NTS commitments improved because of management emphasis on and oversight of this portion of the process. However, management's efforts to ensure NTS closure by the specified due-date tended to focus the staff's attention on the timely completion of the action rather than on the task's contribution to the solution of the problem. Management focus on schedule adherence also resulted in commitments being closed before completion. For example, a licensee consulting engineer, taking part in a Dresden Station engineering self-assessment, noted in an October 7, 1996, report that an NRC commitment was closed after the performance of volute trim work on a CS pump to reduce vibration levels, but the work was only moderately successful. As a result, a new NTS item was generated.

Corrective actions involving several departments or a large portion of the site population were often fragmented into many smaller tasks and recorded as individual NTS commitments by the problem investigation team. No single manager at an appropriate level in the organization was assigned ownership and oversight of the entire problem. Task managers assigned responsibility for completing a single NTS commitment were often not involved in the initial investigation and may not have been aware of the task's importance or its relationship to other commitments. The practice of closing NTS commitments before completing and incorporating unfinished actions into other commitments further exacerbated the task managers' lack of understanding of the full scope and importance of an individual task, as did the transfer of task management responsibilities that occurred as a result of the large number of management and supervisory changes over the past 2 years.

The licensee had performed 96 corrective action effectiveness reviews at the time of the inspection. The effectiveness reviews frequently identified closed NTS items that were incomplete or ineffective. However, further corrective actions generated as a result of the effectiveness reviews also were untimely or ineffective in correcting the problems originally identified. The team attributed the untimeliness and ineffectiveness of the actions taken in response to the results of these effectiveness reviews to the licensee's practice of initiating new PIFs and reinitiating the investigation process. For example, corrective action NTS items involving radioactive material (RAM) and LHRA events resulted in the initiation of Level 4 PIFs rather than Level 2 PIFs, which was the original categorization of the recurring RAM and LHRA events. Additionally, the effectiveness review primarily focused on individual closed NTS items rather than on determining why the corrective actions, as a whole, were unsuccessful in preventing recurring problems.

The team identified that some problems were the same or similar to problems that were identified during the three prior diagnostic evaluations (DEs) at ComEd facilities. Inservice Testing (IST) program deficiencies were identified during all previous DEs and control of excessive overtime was noted during the 1987 DE at Dresden Station and the 1990 DE at Zion.

As recently as December 1995, an NRC violation was issued for failing to preapprove exemptions from the overtime guidelines and in July 1996, the licensee issued a corrective action record (CAR) for additional violations of overtime requirements. During the root cause evaluation for the CAR, the licensee identified additional violations involving the failure of the electrical maintenance department to track overtime. Consequently, two electrical maintenance workers exceeded the NRC Generic Letter (GL) 82-12, "Nuclear Power Plant Staff Working Hours," limit of 72 hours in 7 days during the period of July 17 through 24, 1996, and one instrument maintenance supervisor exceeded the GL 82-12 limit of 24 hours in 48 hours on September 18, 1996, without preapproval. Exceeding the limits of GL 82-12 without obtaining preapproval is contrary to the requirements of TS 6.1.B (Deficiency 50-237(249)/96201-29). The corrective actions for the December 1995 NRC violation should have prevented recurrence.

In order to resolve this recurring problem, the licensee revised Procedure DAP 01-09, Revision 5, "Control of Overtime," to establish a normal scheduled working hour limit of 60 hours per week. Interviews with bargaining unit staff indicated that, before this procedural change, a number of staff members routinely worked to the limits of GL 82-12. Although minor deviations of the new limit occurred because of a lack of clarity in the definition of hours worked on site versus hours on site, these deviations did not exceed the limits.

6.4 Self-Assessment

6.4.1 SQV Performance

The SQV department demonstrated the capability to identify adverse trends and to complete appropriate assessments to characterize problems. The results of interviews revealed that the licensee's staff considered the SQV department to be more intrusive and challenging than in the past and that it was adding value to the station's efforts to improve problem identification and resolution. The most frequently cited reason for the improvement was the recent incorporation of line staff members into the audits, surveillances, and independent safety engineering groups. The independent safety engineering group (ISEG), a part of the SQV department, was identifying some problem areas. For example, the SQV department and ISEG identified deficiencies in configuration management, VETIP and the Setpoints Program. Recent SQV audits, quality checks and surveillances were focused on improving quality and ensuring compliance. However, past corporate quality assurance audits of ComEd's A/Es did not identify the significant problems associated with the design control of calculations.

6.4.2 Station Self-Assessment Program

The overall station self-assessment process was well defined. With exceptions involving engineering, the assessments were effectively implemented and produced significant findings and recommendations.

The development of a program for self-assessment was undertaken in response to a 1994 Dresden Plan commitment. The licensee had conducted 33 assessments within the scope of the program at the time of this inspection. The licensee conducted additional independent assessments of the training and engineering departments. Because these assessments were not completed under the station self-assessment program, the reporting, tracking, and effectiveness review requirements of the program were not applicable.

The assessments completed under the station program, used appropriate evaluation criteria. The self-assessment reports reflected the objectives identified in the initial assessment plan and contained recommendations and corrective actions that were specifically related to the identified problem area.

The quality of self-assessments of engineering activities was not as good as assessments conducted in other areas. For example, a self-assessment of reviews completed under 10 CFR 50.59 was of limited scope and did not identify any significant evaluation weaknesses such as those identified by the team. A self-assessment of the LPCI and CCSW systems performed in September 1996 failed to identify some significant engineering problems associated with those systems that were subsequently identified by the team, as discussed in Section 5.2.5.

Some recommendations from self-assessments were closed on the basis of the conduct of department briefings, referred to as tailgate sessions, without subsequent effectiveness reviews. The April 1996 self-assessment of radiological bagging and tagging identified that several corrective actions were closed on the basis of tailgate sessions on radiological awareness. An assessment performed in the training department and documented in a Training Evaluation Report, dated October 4, 1996, identified that tailgate sessions, in general, were not an effective means of training. The licensee has not yet identified corrective actions to address how items previously closed as a result of these tailgate sessions will be evaluated to determine whether additional action is warranted.

The results of effectiveness reviews of corrective actions related to self-assessment findings could not be assessed because the program was only implemented early in 1996. However, the recurring events in the area of RAM control indicated that not all corrective actions related to the radiological bagging and tagging self-assessment have been effective.

6.4.3 Performance Monitoring

The offsite review function, performance monitoring reports, and PORC activities resulted in improved assessment of performance with some exceptions noted. For example, the licensee identified significant performance problems in the area of corrective actions but not in the area of engineering.

The monthly report focused on the key dimensions of safety, production, and cost. The dimensions in each area had established goals, and progress was monitored against those goals. However, the overall focus of the report was quantitative. The September 1996 report provided historical information about each dimension but did not provide analysis of the significance of each entry or trend.

The quarterly Windows report was a recent addition and the program was still evolving. The quarterly report, dated October 25, 1996, was only the second to be issued. The Windows program had safety, production, and cost as its main focus areas. The governing policy called for increased scrutiny of prolonged poor performance and for examining and increasing the standards for prolonged good performance, ensuring rising standards. Interview results indicated that the overall visibility of the goals established within the Windows program and the understanding of their current status were well understood.

The team reviewed Windows assessments related to the areas in which the team identified problems to determine the degree of effectiveness of the Windows evaluations. The licensee rated performance in repeat events and SQV corrective action evaluations as "unsatisfactory." Performance in overdue and extended corrective actions was rated as "improvement needed." The team concluded that the licensee's overall rating of "additional improvement needed but on an improving trend" for corrective actions was appropriate.

The evaluation criteria for "Engineering Production Performance" included temporary system alterations and calculations. In the Windows report, the licensee rated performance in the area of temporary system alternations as "exceptional" for the past two quarters. The Windows report rated performance in the area of calculations as "improvement needed" in the third-quarter report, an improvement over the "unacceptable" performance noted in the second-quarter report. On the basis of the problems that the team identified in the areas of temporary system alterations (refer to Section 5.4) and the control and quality of calculations (refer to Section 5.1), the team concluded that the licensee's overall rating of "acceptable" for engineering production, which included temporary system alterations and calculations, was not supported.

Although the onsite review function has always existed at Dresden Station, the committee structure was introduced in 1995. Appropriate personnel were assigned to the committee, and PORC meetings had an appropriate safety focus. Questioning by PORC members was sufficient to ensure that appropriate safety-based actions were taken. For example during one PORC meeting, observed by the team, the PORC questioned an operability determination related to the control room ventilation system, and the system was subsequently declared inoperable.

The records of the licensee's offsite review of engineering products, such as LERs, and evaluations performed under 10 CFR 50.59, documented critical and constructive feedback. However, offsite review recommendations did not appear to be handled consistently. Some recommendations resulted in the initiation of NTS items, while others did not. Recommendations that were tracked did not have to be accomplished but only reviewed.

The results of the offsite reviews were summarized and discussed quarterly with the site engineering manager, but the report of these reviews focused on the number rather than the overall quality. When discussing the relative effectiveness of engineering, the site engineering manager cited the graphs in the quarterly report that indicated Dresden Station had the best rating of the ComEd facilities. However, the manager was unable to identify the metric used.

6.5 Root Causes of Significant Findings

The team evaluated the observations and findings of this inspection, as well as the NRC inspection record to identify the probable root causes for previously identified significant problems that had not been corrected and significant problems that had not been previously identified or evaluated for significance. On the basis of this review, the team identified two root causes. The inspection record documented long-standing weaknesses in corrective action effectiveness, and the results of this inspection indicated that a number of long-standing or recurring problems were not corrected. Additionally, the effects of the lack of control of design calculations was a problem area that was not fully recognized.

6.5.1 Management Commitment to Resolving Performance Problems

Until the past 12 to 18 months, corporate and site managers were not fully focused on correcting the organizational, programmatic, process, and material condition problems that have been evident for a number of years. As a result, only some of the issues identified in past reviews have been corrected, most notably site management oversight (Sections 6.1.3 and 6.2) and operator performance (Sections 2.1, 2.2, 2.3, 2.4 and 2.5), which was one of the first priorities of the current SVP. In many instances, corrective actions were still being implemented (Sections 5.5 and 5.6), in others, the corrective actions were not fully effective (Sections 3.4, 3.5, 4.2, 5.2, 5.4 and 6.3.3). In a limited number of areas, particularly engineering (Section 6.5.2), existing performance problems had not yet been recognized or were not fully assessed for significance.

6.5.2 Corporate Oversight of and Involvement With Design Engineering Activities

Corporate management did not provide meaningful oversight of or involvement with their contractor engineering service firms to ensure appropriate design control for design basis calculations. The licensee did not fully appreciate the impact of the growing number of design basis calculations nor the implications of the failure to maintain them (Sections 5.1.1, 5.1.2, and 5.1.3). ComEd eventually institutionalized by procedure the practice of not maintaining design basis calculations, using the experience of the engineers as justification (Section 5.1.7). Acceptance of this practice by corporate managers led to the further degradation of design control and poor quality oversight (Section 6.1.1). In response to previous assessments in this area, the licensee moved the engineering organization to the site in 1994 and increased engineering staffing by hiring a number of contractor engineers, who have worked in the same environment for many years. The transfer of calculations to the site, however, was only completed in 1996, further aggravating the licensee's inability to retrieve design basis information that had not been indexed. Because of the large scope of the engineering initiatives already planned (Section 5.6) and the volume of emergent work (Section 4.2), the restoration of appropriate design control and maintenance of design basis calculations represents a significant challenge to the licensee (Section 5.1.7).

6.6 NRC Inspection History

The inspection record indicated weaknesses in the licensee's ability to correctly identify problems. Past NRC systematic assessment of licensee performance reports identified that the scope of problem evaluations and assessments was narrow. Additionally, the inspection record indicated that there was insufficient justification for assumptions and a lack of thoroughness in documentation associated with engineering processes and evaluations.

The inspection record also indicated weaknesses in the corrective action program. Examples of weak corrective actions included maintenance activities that involved the introduction of foreign material into a CCSW pump in 1994, system checklist and locked valve program problems, ECCS room structural steel problems, and failures of the HPCI system exhaust check valve. One of the most significant corrective action program issues was the performance problems with 4 Kv circuit breakers that involved potential common mode failures because of maintenance and design deficiencies. These problems finally resulted in an extended forced outage in 1996.

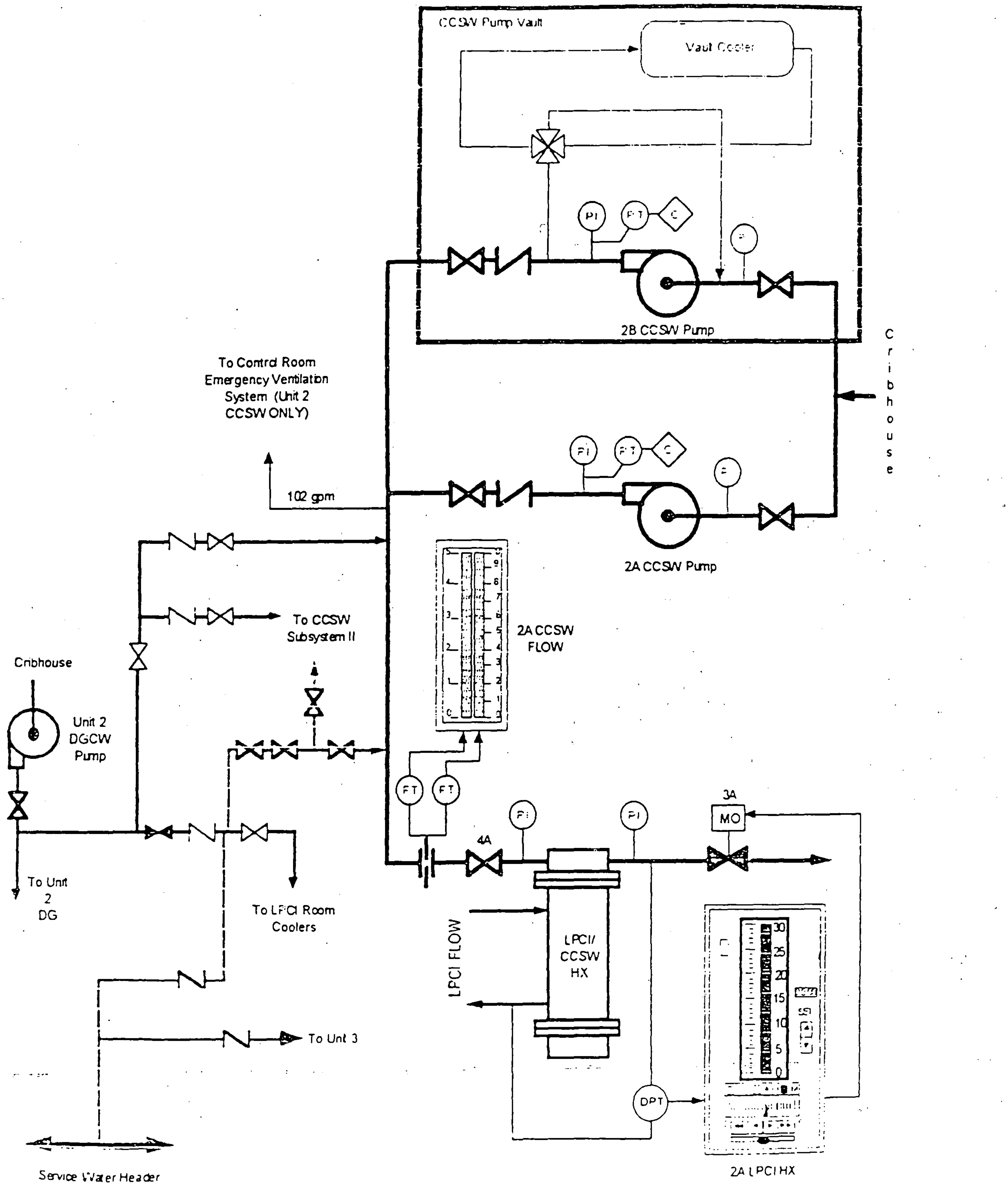
In the area of self-assessment, the inspection record revealed recent initiatives to aid in evaluating and improving engineering performance. It also revealed that the self-assessment of 10 CFR 50.59 evaluations identified several minor problems.

7.0 MANAGEMENT MEETINGS

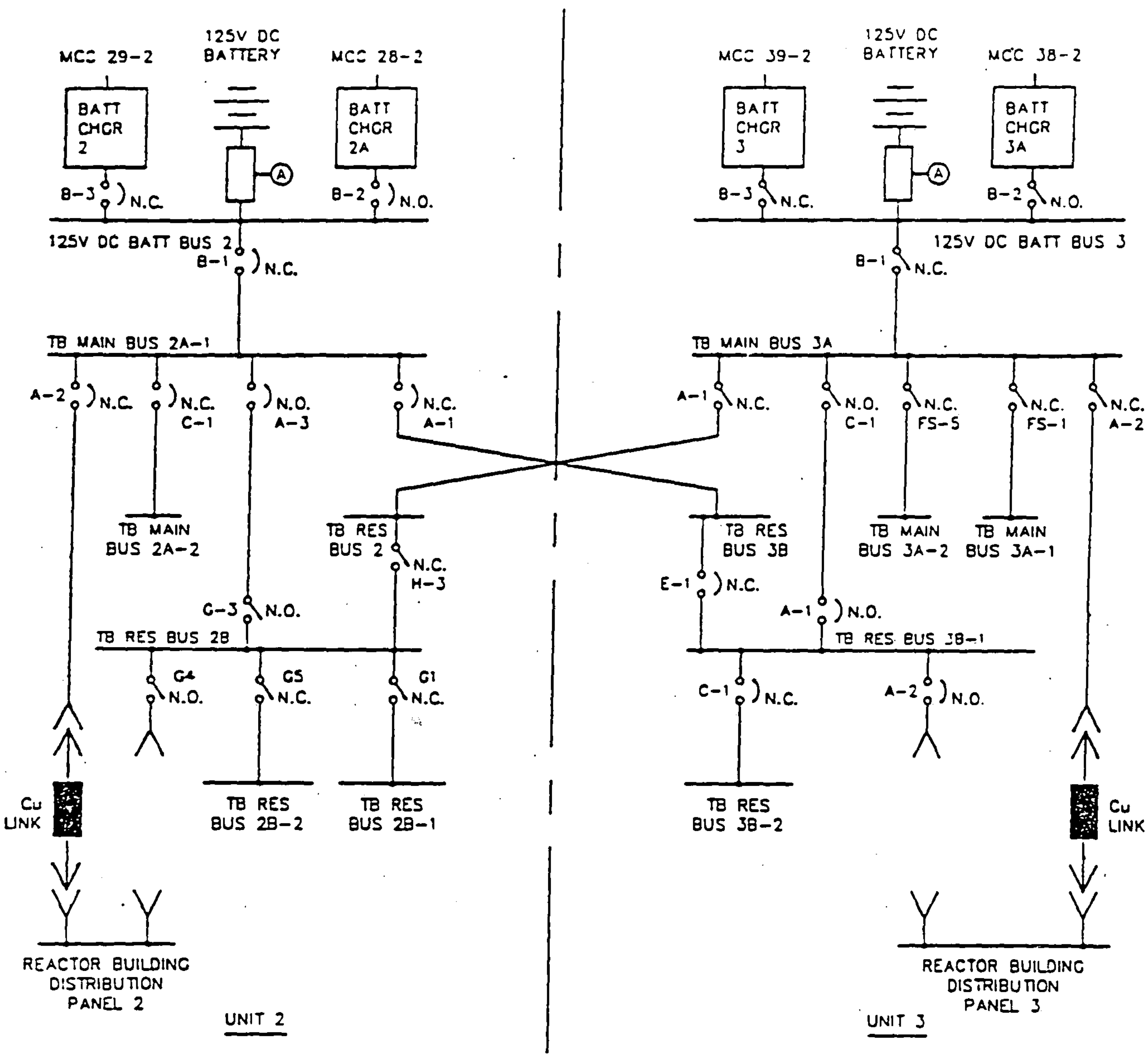
The team conducted two interim exit meetings during the course of this inspection. The first was held on October 11, 1996, at the end of the first 2-week onsite inspection period, and the second was held on November 8, 1996, at the end of the second and final onsite inspection period. The purpose of the interim exit meetings was to provide an integrated discussion of the inspection findings to date.

The team conducted a final meeting, open to public observation, with ComEd representatives at the Dresden Station on December 12, 1996. The observations, findings, and conclusions of this inspection were discussed at this meeting.

CONTAINMENT COOLING SERVICE WATER SYSTEM



APPENDIX A
125 VDC ELECTRICAL DISTRIBUTION SYSTEM



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REF: 12E-2322, SH 1, REV AD
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12E-2322, SH 3, REV AB
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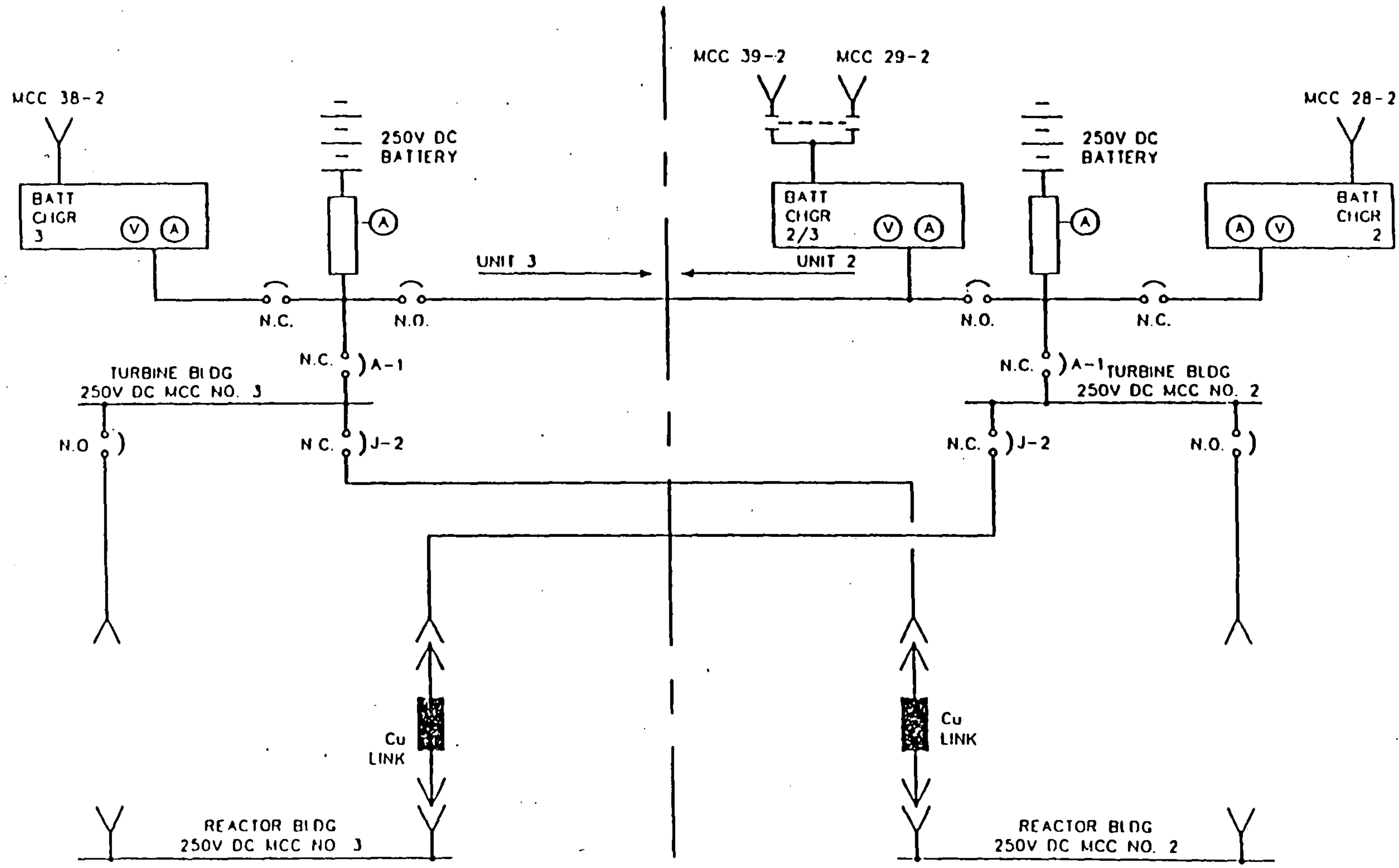
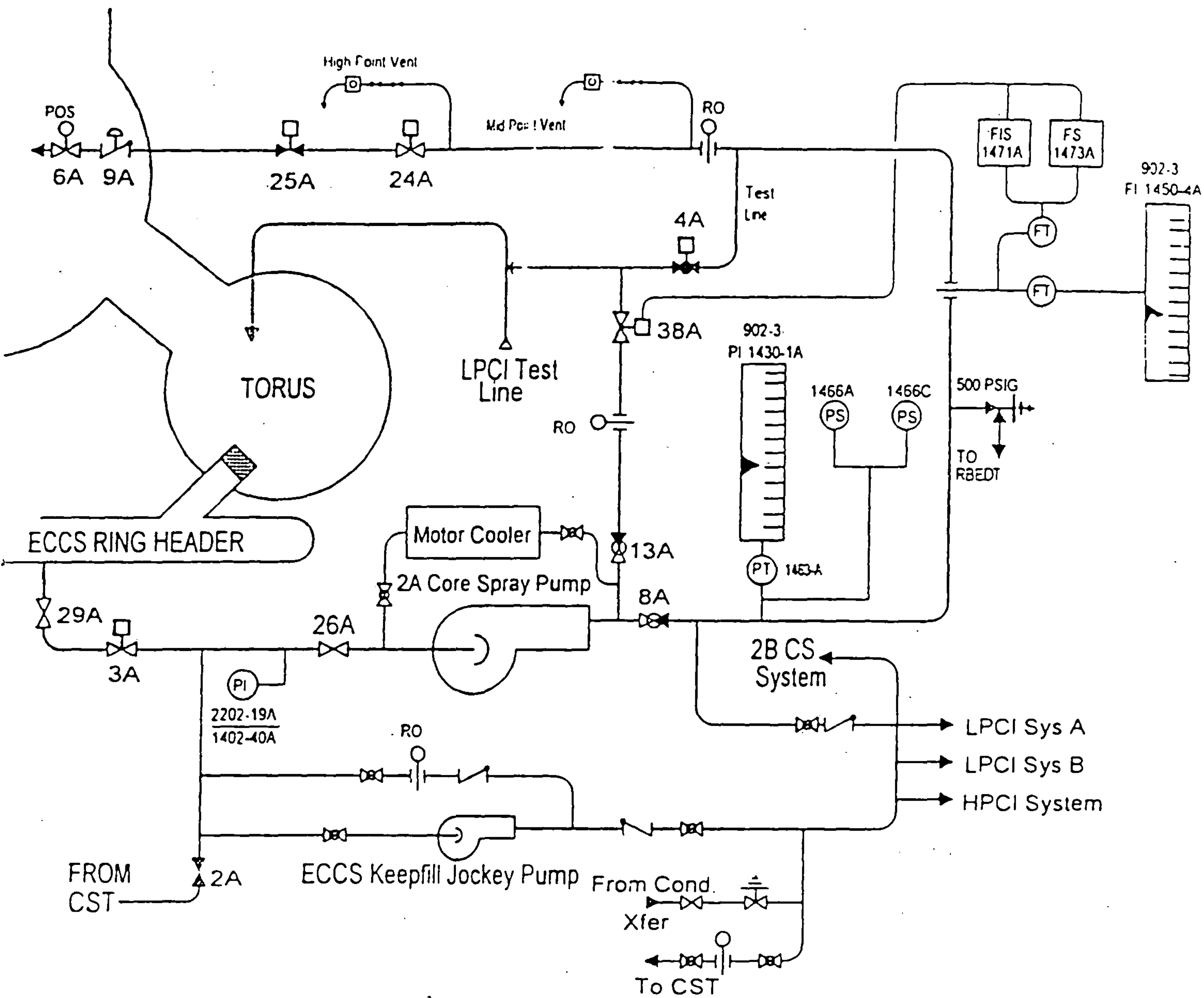
12E-2322B, REV B
12E-3322, REV Z
12E-3322A, REV E
12E-3322B, REV A
DOA 6900-2
DOA 6900-3

APPENDIX A

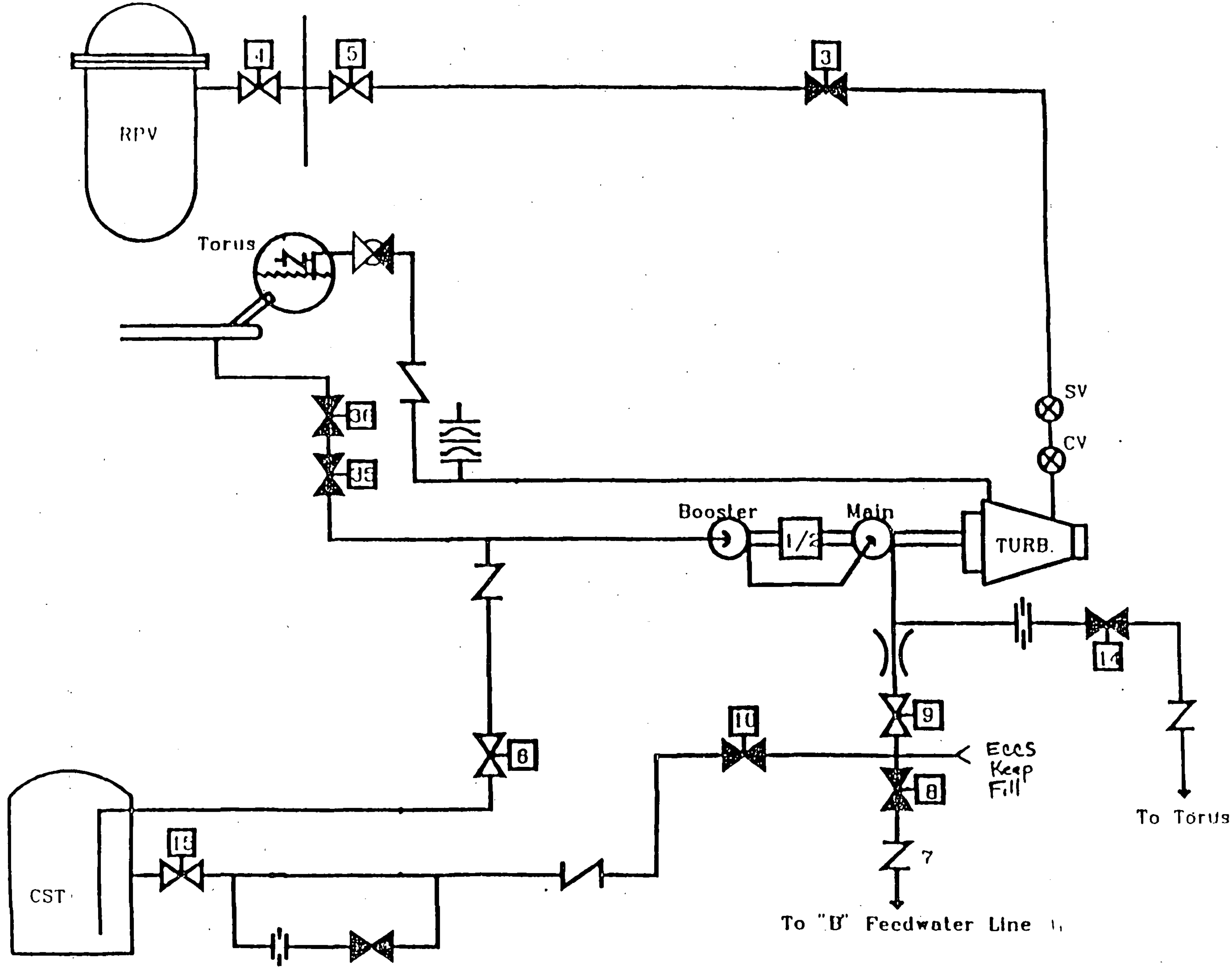
250 VDC ELECTRICAL DISTRIBUTION SYSTEM



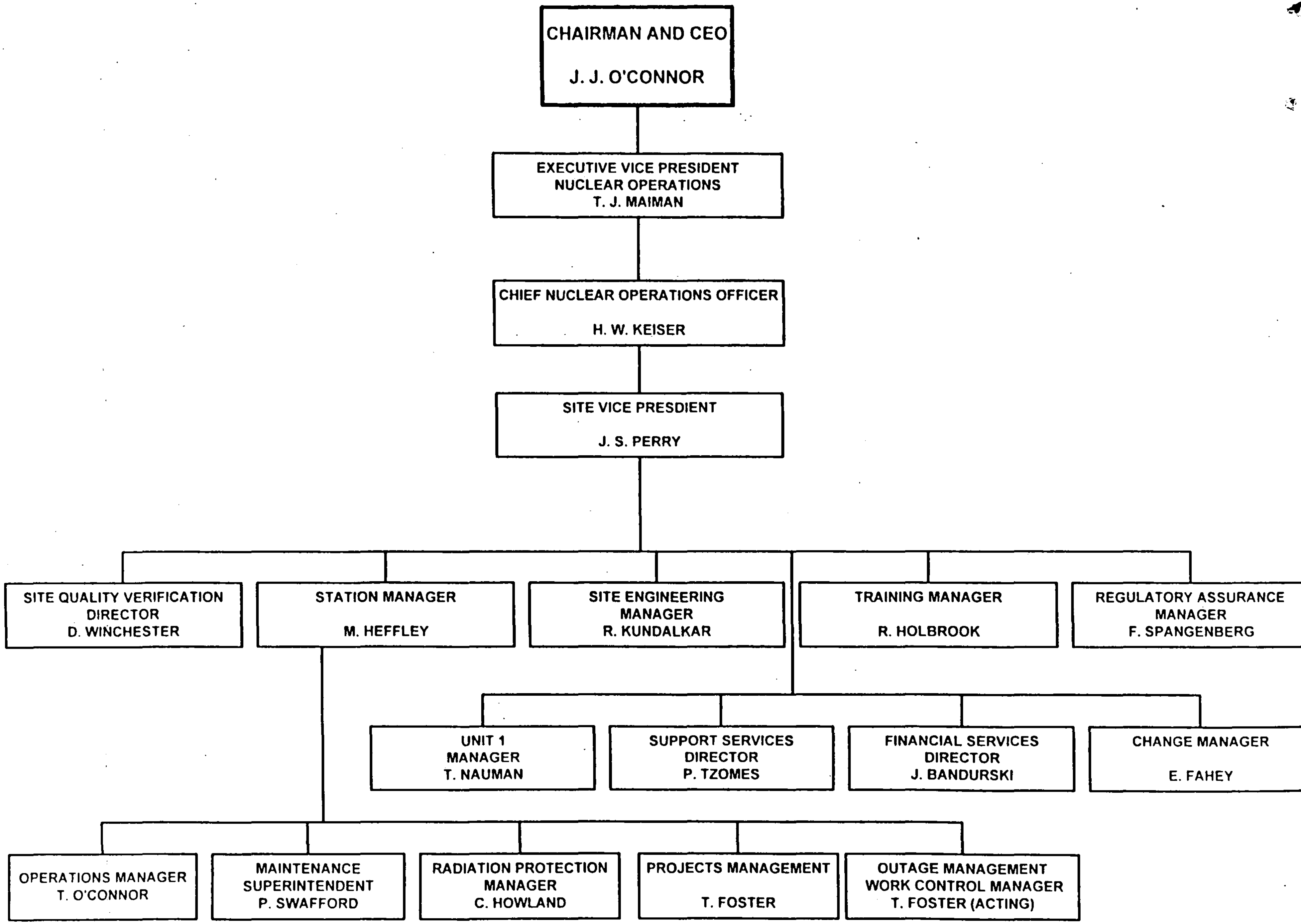
CORE SPRAY SYSTEM



APPENDIX A
HIGH PRESSURE COOLANT INJECTION SYSTEM



DRESDEN STATION ORGANIZATION



APPENDIX C
LIST OF ACRONYMS USED

A/E	Architect-Engineer
AC	Alternating Current
ADS	Automatic Depressurization System
AE	Auxiliary Electric
ALARA	As-Low-As-Is-Reasonably Achievable
AOP	Auxiliary Oil Pump
AR	Action Request
BOP	Balance-of-Plant
BWR	Boiling Water Reactor
CAR	Corrective Action Record
CARB	Corrective Action Review Board
CCSW	Containment Cooling Service Water
CNOO	Chief Nuclear Operations Officer
ComEd	Commonwealth Edison Company
CS	Core Spray
CST	Condensate Storage Tank
DAP	Dresden Administrative Procedure
DATR	Dresden Administrative Technical Requirements
DBD	Design Basis Document
DC	Direct Current
DCP	Design Change Package
DCR	Design Change Request
DE	Diagnostic Evaluation
DET	Diagnostic Evaluation Team
DG	Diesel Generator
DP	Differential Pressure
ECCS	Emergency Core Cooling System
EDSFI	Electrical Distribution System Functional Inspection
ELMS	Electrical Load Monitoring Systems
EOP	Emergency Operating Procedure
ER	Engineering Request
ETRVS	East Turbine Room Ventilation System
FLA	Full Load Current
FME	Foreign Material Exclusion
GE	General Electric
GL	Generic Letter
GSLO	Gland Seal Leak Off
HPCI	High Pressure Coolant Injection
HVAC	Heating, Ventilation, and Air Conditioning
HVO	High Voltage Operator
HRA	High Radiation Area
IEEE	The Institute of Electrical and Electronics Engineers, Inc.
ILRT	Integrated Leak Rate Test
IN	Information Notice

IPE	Individual Plant Evaluation
IRP	Integrated Reporting Process
ISEG	Independent Safety Engineering Group
ISI	Independent Safety Inspection
IST	Inservice Testing
IWG	Inch-Water-Gauge
JAM	Job Assignment Matrix
KV	Kilovolt
KVA	Kilovolt Amperes
LER	Licensee Event Report
LHRA	Locked High Radiation Area
LLRT	Local Leak Rate Test
LOCA	Loss of Coolant Accident
LOOP	Loss-of-Offsite Power
LPCI	Low Pressure Coolant Injection
M&TE	Measuring & Test Equipment
MCC	Motor Control Center
MOV	Motor-Operated Valve
MPFF	Maintenance Preventable Functional Failure
MTU	Master Trip Unit
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NOD	Nuclear Operating Division
NPSH	Net Positive Suction Head
$NPSH_A$	Net Positive Suction Head-Available
NRC	U.S. Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
NTS	Nuclear Tracking System
NUMARC	Nuclear Management and Resources Council
O&M	Operating and Maintenance
OE	Operability Evaluation
OPE	Operating Experience Engineer
OSPRE	On-Line Safety Predictor
P&ID	Piping & Instrumentation Diagram
PCM	Performance-Centered Maintenance
PCT	Peak Cladding Temperature
PIF	Performance Improvement Form
PM	Preventive Maintenance
PMT	Post-Maintenance Testing
PORC	Plant Operations Review Committee
PRA	Probabilistic Risk Assessment
RAM	Radioactive Material
RP	Radiation Protection
RPA	Radiological Posted Area
RPSS	Radiation Protection Shift Supervisor

LIST OF ACRONYMS USED (cont.)

RPV	Reactor Pressure Vessel
RUFSAR	Revised Updated Final Safety Analysis Report
RWP	Radiation Work Permit
SBLC	Standby Liquid Control
SBO	Station Blackout
SJAE	Steam Jet Air Ejectors
SMRO	Site Maintenance Rule Owner
SQV	Safety Quality Verification
SSC	Structures, Systems, or Components
SVP	Site Vice President
SWSOPI	Service Water System Operational Performance Inspection
TDH	Total Developed Head
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
UPS	Uninterruptable Power Supply
USQ	Unreviewed Safety Question
V	Volt
VAC	Volts-Alternating Current
VAT	Vulnerability Assessment Team
VDC	Volts-Direct Current
VETIP	Vendor Equipment Technical Information Program
WR	Work Request

APPENDIX D
PARTIAL LIST OF PERSONNEL CONTACTED

Bandurski, Jeff	Financial Services Director
Barrett, Steve	Site Vice President's Assessor
Boyle, Patrick	Operational Health Physics/ALARA Lead
Coyle, Lawrence	Operations Shift Engineer
Foster, Terry	Work Control Projects Manager
Freeman, Russ	Plant Engineering Superintendent
Harlach, John	Mechanical Maintenance Master Mechanic
Heffley, Mike	Station Manager
Holbrook, Robert	Training Manager
Howland, Cliff	Radiation Protection Manager
Johnson, Wayne	Fuel Handler, Chief Union Steward
Keiser, Harry	Chief Nuclear Operations Officer
Kish, John	Plant Engineering Senior System Engineer
Kuczynski, Steve	Shift Operations Supervisor
Kundalkar, Raj	Site Engineering Manager
Latkoczy, Laszlo	Plant Engineering Engineer, Maintenance Rule Owner
Lechton, Terry	Nuclear Change Management
Maiman, Thomas	Executive Vice President, Nuclear Operations
Nugent, George	Mechanical Maintenance Mechanic, Union Steward
O'Connor, Jim	Chairman and Chief Exective Officer
O'Connor, Tim	Operations Manager
O'Neil, Joe	Radiation Protection Technician, Union Steward
Perry, Steve	Site Vice President
Peters, Jim	Electrical Maintenance Electrician, Union Steward
Pliml, George	Quality Services Director
Richards, Carl	Site Quality Verification Audit Supervisor
Richardson, Jim	Human Resources Supervisor
Schimmel, Mark	Construction Maintenance Superintendent
Scott, Robert	Site Quality Verification ISEG Supervisor
Spangenberg, Frank	Regulatory Assurance Manager
Stachniak, Robert	SQV Corrective Action Process Supervisor
Swafford, Preston	Maintenance Superintendent
Szumski, Dan	Plant Engineering Programs Group Lead
Tietz, Gerald	Plant Engineering Safety System Lead
Tzomes, Pete	Support Services Director
Waldinger, Lon	Nuclear Oversight Manager
Ward, Robert	Director of Safety Review
Williams, Joe	Engineering Programs Supervisor
Winchester, Dennis	Site Quality Verification Director
Yarbrough, Tim	Maintenance Staff Self-Assessment Coordinator
Zehrung, Dave	Operations Staff Supervisor

APPENDIX E
LIST OF DOCUMENTS REVIEWED

Throughout the inspection period, the team and the licensee maintained a controlled index of documents that were provided to the team for review. This index was placed in the Public Document Room under separate correspondence, dated December 13, 1996.

APPENDIX F
DEFICIENCIES

DEFICIENCY: Is either (a) the apparent failure of the licensee to comply with a requirement (violation) or (b) the apparent failure of a licensee to satisfy a written commitment or to conform to the provisions of applicable codes, standards, guides or accepted industry practices when the commitment has not been made a legally binding requirement (deviation).	
DEFICIENCY	**NUMBER**
Failure to maintain an adequate annunciator procedure contrary to 10 CFR Part 50, Appendix B, Criterion V	96201-01
Failure to perform surveys contrary to the requirements of 10 CFR 20.1501(a)	96201-02
Failure to specify a maximum stay time on a radiation work permit and maintain locked high radiation area doors locked contrary to TS 6.12.2 and 10 CFR 20.1601	96201-03
Failure to have conspicuous radioactive material postings contrary to the requirements of 10 CFR 20.1902(e)	96201-04
Failure to document an inventory of locked high radiation area keys contrary to DAP 12-12 and TS 6.2	96201-05
Failure to maintain control of radioactive material contrary to the requirements of 10 CFR 20.1802	96201-06
Failure to provide sufficient information on labeled radioactive material contrary to the requirements of 10 CFR 20.1904	96201-07
Failure to implement ARs contrary to the requirements of DAP 11-02	96201-08
Failure to initiate PIFs contrary to the requirements of DAP 02-27	96201-09
Failure to implement a PMT contrary to the requirements of the work instructions (WR960026808)	96201-10
Failure to include Unit 1 within the scope of the maintenance rule contrary to the requirements of 10 CFR 50.65	96201-11
Failure to perform evaluations contrary to the requirements of 10 CFR 50.59	96201-13
Failure to implement corrective actions contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion XVI	96201-14

DEFICIENCY: Is either (a) the apparent failure of the licensee to comply with a requirement (violation) or (b) the apparent failure of a licensee to satisfy a written commitment or to conform to the provisions of applicable codes, standards, guides or accepted industry practices when the commitment has not been made a legally binding requirement (deviation).

DEFICIENCY	NUMBER
Failure to secure ladders while not in use contrary to the requirements of DAP 07-48	96201-15
Failure to test HPCI valves contrary to Section XI of the ASME Code and TS 3.0.D	96201-17
Failure to test the Unit 2, 125 Vdc battery contrary to Procedure DES 8300-28	96201-18
Failure to perform an acceptable service test of the Unit 2, 250 Vdc battery contrary to the requirements of TS 4.9.A.3	96201-19
Failure to maintain an adequate procedure for testing the control room HVAC system contrary to 10 CFR Part 50, Appendix B, Criterion V	96201-20
Failure to perform a prompt operability determination evaluation within the time specified by DAP 07-31	96201-21
Failure to translate the design into drawings, specifications, and procedures contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion III	96201-22
Failure to update the UFSAR contrary to the requirements of 10 CFR 50.71(e)	96201-23
Failure to implement commitments in response to Generic Letter 90-03	96201-28
Failure to control work hours contrary to the requirements of TS 6.1.B	96201-29

APPENDIX G
UNRESOLVED ITEMS

UNRESOLVED ITEM: An item for which more information is required to ascertain whether the item is acceptable or deficient.

UNRESOLVED	ITEM NUMBER
Acceptability of the use of MPFFs in the determination of reliability for standby systems within the scope of the maintenance rule	96201-12
Acceptability of ECCS relief valve setpoints	96201-16
Acceptability of replacement circuit breaker associated with the HPCI GSLO condenser drain pump motor	96201-24
Acceptability of not considering ECCS instrument uncertainty	96201-25
Acceptability of the nitrogen inerting system flow rate	96201-26
Acceptability of removing Valve MO 2(3)-2301-15 from the scope of the Generic Letter 89-10 testing program	96201-27

ATTENDANCE LIST FOR THE INDEPENDENT SAFETY INSPECTION EXIT MEETING

LICENSEE/FACILITY	Commonwealth Edison Company Dresden Nuclear Power Station
DATE/TIME	December 12, 1996, 9 a.m.
CONFERENCE LOCATION	Dresden Nuclear Power Station Training Center

NAME (PLEASE PRINT)	ORGANIZATION	TITLE
Art Howell	USNRC - RIV	ISI TEAM LEADER
Rich Kotula	ComEd	Photographer
GARY WALD	ComED	NUC. COMMUNICATIONS. ADMIN.
NEAL McCann	MAYSA Comm.	Audio Tech
Mark NAVARRO	S+L	SR. Proj. Engr
Tim Kirkham	ComEd	Technical HP Manager
Tim Yarbrough	ComED	Maintenance Specialist
JOHN Schrage	ComEd	SUPPLY DIRECTOR WHOLESALE MARKETING DEPT.
LON WALDINGER	ComEd	Nuclear Oversight MANAGER
Greg Howard	ComEd	ISI Counterpart
Norm Weber	Mollerus Engrs	ISI Team
DAVE BROWN	IDNS	EP Coordinator
John M Almeter	ComEd	DRESDEN - QUALITY FIRST ADMINISTRATOR
J.W. Zosenteck	ComEd	Z... RA
HAL DODD	ComED	NUCLEAR STATION Operator
Jerry DeYoung	ComED	Gov Affairs (EP)

ATTENDANCE LIST FOR THE INDEPENDENT SAFETY INSPECTION EXIT MEETING

LICENSEE/FACILITY	Commonwealth Edison Company Dresden Nuclear Power Station
DATE/TIME	December 12, 1996, 9 a.m.
CONFERENCE LOCATION	Dresden Nuclear Power Station Training Center

NAME (PLEASE PRINT)	ORGANIZATION	TITLE
Jeff Hansen	NRC	Dresden Resident Inspector
Patricia L Falletti	PECO	Admin Supervisor
Mark Falcone	ComEd	Exec Assistant
Fred Dacksame	Com Ed	Finance Director
Brian McCabe	NRC	✓
Jim Taylor	NRC	✓
Robert Whalen	ComEd	Asst to Station Manager
John Siladv	"	NFS Engr. Support Team
Whit Hansen	NRC	Contractor
Phil Cirrencione	Sun Tech	Contractor
J Lynch	NRC	State Liaison
C. Howland	ComEd	RPM
J. Ketz	Com Ed	MMD - Union Steward
James Templin	Alantic	Buckstop Planner
Dan Demos	ComEd	Public Affairs Director
Don Gould	Will County EMA	Director

ATTENDANCE LIST FOR THE INDEPENDENT SAFETY INSPECTION EXIT MEETING

LICENSEE/FACILITY	Commonwealth Edison Company Dresden Nuclear Power Station
DATE/TIME	December 12, 1996, 9 a.m.
CONFERENCE LOCATION	Dresden Nuclear Power Station Training Center

NAME (PLEASE PRINT)	ORGANIZATION	TITLE
JOHN NASH	GE NUCLEAR ENERGY	SITE MGR.
ROY WIGHT	IL. DEPT OF NUC. SAFETY	MGR, ONFS
JOSEPH O'NEIL	ComEd-Dresden-RP	RP TECHNICIAN-(STEWARD)
ALLYN C SETTLES	IDNS	Resident Inspector
Roger Heider	SARGENT & LUNDY	Proj Dir.
JAN STRASMA	NRC	
RON WIGGINS	ComEd DRESDEN	I/M MASTER
Jim Richardson	ComEd Dresden	H.R. Supervisor
[illegible]	ComEd Dresden	Outage Management
John Hosmer	ComEd ENG	ENG VP
Pat Hiland	NRC	Branch Chief
ROY ZIMMERMAN	NRC	NRR ADP
David Roth	NRC	Resident
Shirley Lambros	CeCo	Steward
JAMES O'CONNOR	CECo	Chairman
DAN SZUMSKI	CE Co	ENGINEERING DRESDEN

ATTENDANCE LIST FOR THE INDEPENDENT SAFETY INSPECTION EXIT MEETING

LICENSEE/FACILITY	Commonwealth Edison Company Dresden Nuclear Power Station
DATE/TIME	December 12, 1996, 9 a.m.
~~CONFERENCE LOCATION~~	~~Dresden Nuclear Power Station Training Center~~

NAME (PLEASE PRINT)	ORGANIZATION	TITLE
THOMAS L. NAUMAN	ComEd	DRESDEN UNIT-1 PLANT MANAGER
[illegible] Tirone	ComEd	Dresden Steward
JACK BRONS	ComED	D.G.
TIM EASON	ComED	DRESDEN STATION
BOB RYSNER	Com ED	SQV AUDITOR
CARLIS RICHARDS	ComED	SQV AUDIT SUPV.
Dennis Winchester	ComED	SQV Director
TOM THORSELL	COMED	CHIEF ENG. E/I&C
ROBERT FRY	ComEd	QC SUPV.
Mike Heffley	Com Ed	Sta Mgr
Preston Swafford	Com Ed	~~Stay~~ Maint Supt
Joe Stimel	Com Ed	Chemistry
DAVE Schosnick	Com Ed	CHEMISTRY
M KORCHYNSKY	COM ED	OPERATIONS
WAYNE JOHNSON	COM ED	FUEL HDLG
STEVE TUTWIT	ComED	DESIGN ENG.

ATTENDANCE LIST FOR THE INDEPENDENT SAFETY INSPECTION EXIT MEETING

LICENSEE/FACILITY	Commonwealth Edison Company Dresden Nuclear Power Station
DATE/TIME	December 12, 1996, 9 a.m.
CONFERENCE LOCATION	Dresden Nuclear Power Station Training Center

NAME (PLEASE PRINT)	ORGANIZATION	TITLE
JOHN M. HARLACH	DRESDEN (COMED)	MASTER MECHANIC
R. Freeman	Dresden	SEM
R. Stachniak	Dresden	SQV
R. Kundalkar	Dresden	Eng
K Ross	NOD	Comm
Bill Stam	Local 15 IBEW	Pres/Bus/Mgr
Steve Kuczynski	Dresden	Shift Ops Sup
Joe Williams	Dresden	Plant Eng Supt.
Steve Stiles	Dresden	INST. MAINT. [illegible]
E CONNELL	DRESDEN	DES. ENG SUPT
TERRY RIECK	COMED - NFS	CHIEF NUCLEAR ENGR
Bob Smith	COMED Dresden	WEA
Bob Scott	ComEd Dresden	ISEG Supervisor
Demetrius L. Willi,	ComEd "	Electrical
BRIAN GRANT	DRESDEN	OPERATIONS
Bob Rybak	~~Dresden~~ ComEd	Corp

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NAME (PLEASE PRINT)	ORGANIZATION	TITLE
Brian Barth	S+L	Site Proj Manager
JOHN DAWN	Com Ed-Dresden	LEAD MECH. DES. Engr — MECH COUNTERPART TONRE
GARY ABRELL	COMED - DRESDEN	REGULATORY AUDIT ADMINISTRATOR
LIZ ROALSEN	-GLAD	ISI TEAM
Charles E. Beck	Kiran Consultants, Inc	Director of Nuclear Operations
PEG Lucky	ComED	CF Supervisor
W. Baer	MLB	Atty
A.K. SINGH	S+L	ISI Expert
J S PERRY	COMED	VP
O.S. MAZZONI	NRC/SRI	INSPECTOR
J. S. ALMON	COMED	P.E. LEAD
PAT Murray	Comed	SQV Corrective Actions
Larry Ferguson	ComEd	Rad. Prot. Tech.
Lois Jordan	ComEd	Tech Trng Supv
W. Deagle	ComED	Ops Inst.
DAVID W Jenkins	ComEd	LEGAL

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NAME (PLEASE PRINT)	ORGANIZATION	TITLE
Howard Wong	NRC	ISI - Engr Lead
John Stang	NRC	NRR/Project Manager
IRENE M JOHNSON	COMED	LICENSING DIRECTOR
Robert A. Capra	NRC	Project Director
Mary Ann M. Biamonte	NRC	Trng: Assessment Specialist
Tom MAIMAN	ComEd	Exec VP
JIM PHELAN	ComEd	STAFF ENGR - ISI TEAM
ROGER SCHIAVONI	S&L	PROJECT ENGINEER
Jim Peters	ComEd	STEWARD
Brian [illegible]	ComEd	Sr. Staff Engineer - NES
James A. Isom	NRC	OPS. ENGINEER
MARK D Uhrich	Comed-QUAD	SUPPORT ENGINEER
Kirk Robbins	Com Ed	Plant Eng ISI I&C Response
B. Hanson	Com Ed	Operations
David C. Tobbs	MidAmerican Energy	SR. ENGINEER
C.A. Tzomes	ComEd	Services Director

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NAME (PLEASE PRINT)	ORGANIZATION	TITLE
CLARK VANDERNIET	USNRC	SRT
Terry Foster	Dresden WC	Outage/WC Mgr
Paul Planing	Dresden Eng	Project Manager
Michael P. Shannon	U.S NRC	Radiation Specialist
MICHAEL SHLYAMBERG	USNRC/CONSULT	MECH. ENG.
Timothy J. O'Connor	Com ED	Operations Mngr Dresden
JOSEPH R. BASAK	DE&S	ENGINEERING MGR
DAVID M. STIBLE	CECO	INSTRUCTOR
Carol Gordon	NRC	administrative assistant
William B. Jones	NRC	Senior Reactor Analyst - RIV
Tom Foley	NRC	Senior Engineer
Bruce Tanouye	Com Ed	Const. Supt

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NAME (PLEASE PRINT)	ORGANIZATION	TITLE
Sam Collins	NRC - ISI	Team Manager
DELFO BIANCHINI	SARGENT + LUNDY	PROJECT MANAGER
L. ZRUBEK	G.E	MGR -
[illegible] MILSAP	ComEd Site Communication	Site Communication Director
Frank Spangenberg	ComEd	Regulatory Assurance Mgr.
Thomas Esper	IDNS	RESIDENT INSPECTOR
Elbert Carroll	ComEd	Reg Assurance
Robert Taylor	ComEd	ATTORNEY
BILL BEACH	NRC	REGIONAL ADMINISTRATOR
GREG TICE	QUAD CITIES DESIGN ENG'R	PROJ. MG'R - ISI TEAM
DeAnna Biagini	Dresden Station	Comm Specialist
Sharon Ryan	S+L	DIV MGR
Jeff Bandurski	ComEd	Financial Director
[illegible] Kemp	ComEd	CNCC
Valerie Barnes	PSHA	ISI Team
Geoffrey Grant	NRC	DRS

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NAME (PLEASE PRINT)	ORGANIZATION	TITLE
Phil Braghini	Dresden Station Security	Security Administrator
Frank Sadnick	Burns Security	Staff Assistant.
Darrell Tielbur	Burns Security	Operations Coordinator
David L Koehn	Burns	SFM
Kim Boban	Burns	Supervisor
Kathi Haigh	Burns	Supervisor
J Buchanan	[illegible]	Staff
Margaret Clark	Burns	Supervisor

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NAME (PLEASE PRINT)	ORGANIZATION	TITLE
JAMES LINVILLE	NRC	ISI, MEO FUNCTIONAL AREA LEAD
JIM LUTZ	GRCO ESDA	COORDINATOR
BOB DUNN	ComEd	VALVE PROJECT MANAGER
Terrence W. Simpkin	ComEd	Regulatory Assurance Supv - Braid
George Nugent	ComEd	MMD Steward
Jeff Clark	S&L	Design Engineer

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NAME (PLEASE PRINT)	ORGANIZATION	TITLE
Tony Bezouska	Dresden ComEd	Maint. Staff Supv.
Bob Tsai	ComEd - NFS	BWR Safety Analysis Supervisor
Joe Shereman	ComEd - Dresden - WC	Work Analyst
Wayne Shafer	Self	
Thomas Rundy	Coal City Unit #1	Business Manager
Frank Turbeville	Dresden - Maint	Staff Asst
Jim Coonan	Self	—
Larry Thomas	Selv	

ATTENANCE LIST FOR THE INDEPENDENT SAFETY INSPECTION EXIT MEETING

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DATE/TIME	December 12, 1996, 9 a.m.
CONFERENCE LOCATION	Dresden Nuclear Power Station Training Center

NAME (PLEASE PRINT)	ORGANIZATION	TITLE
JIMMY SCIDITA	ENVIRO LAW + POLICY CENTER	FINANCIAL ANALYST

PRESS MEMBER

PUBLIC VISITORS SIGN-IN

Date 12/12/96 Activity/Purpose ISI Public Mtg.

Time IN	Affiliate Organization	NAME (Print)	NAME (Signature)
8:35A	Associated Press	TAMARA STARKS	Tamara B Starks
8 50	JIM RITTER	SUN-TIMES	Jim Ritter
855	WTDK/West Radio Morning	Dean Tambling	Dean D Tambling
8:55	CHICAGO TRIBUNE	PETER KENDALL	Peter Kendall

PRESS MEMBER

PUBLIC VISITORS SIGN-IN

Date ________________ Activity/Purpose ______________________________

Time IN	Affiliate Organization	NAME (Print)	NAME (Signature)
9 30	MORRIS HERALD	JoANN HUSTIS	JoAnn Hustis
9 30	WB	T. ANDREOLI	[illegible]

UNITED STATES NUCLEAR REGULATORY COMMISSION

INDEPENDENT SAFETY INSPECTION

OF

DRESDEN NUCLEAR POWER STATION

PUBLIC MEETING

DECEMBER 12, 1996

SITE SELECTION AND INSPECTION OBJECTIVES

- Dresden has been on the NRC's Watchlist (Category 2) for a prolonged period.
- Evaluate the effectiveness of the corrective action programs.
- Provide an independent assessment of conformance to the design and licensing basis.
- Evaluate the conduct and effectiveness of maintenance activities, including: work processes, post-maintenance testing, and maintenance rule activities.
- Provide an independent assessment of operational safety performance.

INDEPENDENT SAFETY INSPECTION TEAM ATTRIBUTES

- Large, experienced team
- Independent of NRC Region III
- Observation by the State of Illinois
- Modified Diagnostic Evaluation process

DRESDEN ISI TEAM ORGANIZATION

- **Samuel J. Collins**, Team Manager, RIV
  Arthur T. Howell, Team Leader, RIV
  - **Thomas Esper**, Observer, State Representative
  - **Carol J. Gordon**, Administrative Assistant, RIV
  - **John Pellet**, Operations Lead, RIV
    - **Bobby Holbrook**, Ops. Inspector, RII
    - **Michael Shannon**, Rad. Inspector, RIV
  - **William Jones**, Maint. & Testing Lead, RIV
    - **Charles Petrone**, Maint. Rule Inspector, NRR
    - **James Isom**, Inspector, NRR
    - **Thomas Foley**, Inspector, NRR
    - **Claude Johnson**, Inspector, RIV
  - **Howard Wong**, Eng./Tech. Spt. Lead, RIV
    - **George Kalman**, Eng. Programs Insp., NRR
    - **Michael Shlyamberg**, Mech. Design Insp., Contractor
    - **Cyril Crane**, Elec. Design Insp., Contractor
    - **Dr. Omar Mazzoni**, Elec./I&C Design Insp., Contractor
  - **James Linville**, Mgmt. & Org. Lead, RI
    - **Mary Ann Biamonte**, Inspector, NRR
    - **Whitney Hansen**, Inspector, Contractor
    - **Dr. Valerie Barnes**, Inspector, Contractor

LICENSEE SUPPORT ORGANIZATION

- Counterparts provided

- Dresden and contractor staff support
  - → Technical and administrative

- Development of extensive response library

- Formal request/response tracking provided

- Daily Team Leader debriefings

- Two interim exit debriefs at site with management
  - → October 11, 1996
  - → November 8, 1996

SCHEDULE

Team Preparation	September 13 - 27
Public Entrance Meeting	September 30
First Onsite Inspection	September 30 - October 11
Second Onsite Inspection	October 28 - November 8
Public Exit Meeting	December 12
Inspection Report Issuance	Late December
Refueling Outage Observations	To be determined

INDEPENDENT SAFETY INSPECTION ACTIVITIES

- Plant and system walkdowns
- Safety system functional inspection of several specified systems:
  - → Core Spray System
  - → High Pressure Coolant Injection System
  - → 125 Vdc Electrical Distribution System
  - → 250 Vdc Electrical Distribution System (partial)
  - → Containment Cooling Service Water System (partial)
- Interviews at multiple levels
- Program, process, and document reviews
- Direct observations of activities
  - → Main Control Room activities
  - → Work in progress
- Case studies

OVERALL CONCLUSIONS

- Overall safety performance has improved.
- Improvement is incremental and rate varies among areas reviewed.
- Significant challenges to continued improvement exist.

OPERATIONS

- Positive Observations/Strengths

  → Operator performance
  → Conservative operating philosophy
  → Management involvement

- Weaknesses

  → Threshold for identification of problems
  → Hardware challenges
  → Reliance on engineering judgment

RADIOLOGICAL PROTECTION

- Positive Observations/Strengths

  → Personnel radiation exposure reduction
  → Personnel contamination event reduction
  → Source term reduction

- Weaknesses

  → Procedural compliance
  → Implementation and understanding of management expectations
  → Control of high radiation areas and radioactive material
  → Radiation worker knowledge and performance

MAINTENANCE

- Positive Observations/Strengths

  → Process enhancements
  → General material condition
  → Maintenance Rule implementing procedures and staff knowledge
  → Basic skills training for maintenance workers

- Weaknesses

  → Equipment reliability and availability
  → Level of emergent work
  → Schedule effectiveness
  → Rework/repeat work
  → Worker implementation of management expectations

TESTING

- Positive Observations/Strengths
  - → Recent identification and resolution of some significant testing weaknesses
- Weaknesses
  - → 250 Vdc battery testing
  - → 125 Vdc battery testing
  - → Control room ventilation testing
  - → Inservice testing program
  - → Relief valve setpoint determination
  - → Post-maintenance testing program

ENGINEERING AND LICENSING/DESIGN BASIS

- Positive Observations/Strengths
  - → Partially implemented modification closure progress
  - → Backlog reduction plans

- Weaknesses
  - → Potential Unreviewed Safety Questions
  - → Design control of calculations
  - → Degraded margins
  - → Safety evaluation adequacy
  - → Problem identification and resolution
  - → Potential design vulnerabilities

ENGINEERING AND LICENSING/DESIGN BASIS (CONTINUED)

- Weaknesses (continued)
  - → Consistency of design and licensing basis information
  - → Temporary system alterations
  - → Modification quality
  - → Reliance on architect/engineers
  - → Completeness and accuracy of information provided

CORRECTIVE ACTION PROGRAMS

- Problem Identification
  - → Generally improved
  - → Design engineering is a notable exception

- Corrective Action Effectiveness
  - → Some organizational, programmatic, and hardware problems have been resolved but a number of long-standing or recurring problems are still unresolved
  - → Some corrective action process weaknesses

- Self-Assessment
  - → Recent improvement with inconsistent results
    - ○ Some assessments are of good quality while others are not
    - ○ Too early to assess adequacy of corrective actions
  - → Improved Site Quality Verification effectiveness

CORRECTIVE ACTION PROGRAMS (CONTINUED)

- Improvement Plans

  → Some action plans have effectively addressed problems while others have not
  → Significant management attention focused in past two years

- Employee Concerns Program

  → High level of awareness
  → Generally perceived as not necessary
  → Concerns about a lack of anonymity evident in an isolated area

PROGRAM PERFORMANCE CONCLUSIONS

- Operations: Significant operator performance improvement noted with challenges in the areas of identification and resolution of material condition problems

- Radiological Protection: Significant reduction of personnel exposure and contamination events with multiple examples of corrective action and procedural compliance problems noted

- Maintenance: Process improvements and some material condition improvements noted but the ability to perform planned work is continually challenged by a high level of emergent work

PROGRAM PERFORMANCE CONCLUSIONS (CONTINUED)

- Testing: Recent improvement in the identification of some significant testing issues, while other significant testing deficiencies were not recognized or resolved

- Engineering and Design/Licensing Basis: Some backlog reduction improvements with significant design/licensing basis weaknesses noted

- Corrective Action Programs: Problem identification generally improved with significant corrective action weaknesses noted

SUMMARY OF REGULATORY FINDINGS

- Deficiencies: Instances of the apparent failure to comply with a requirement (violation) or the apparent failure to satisfy a written commitment that is not a legally binding requirement (deviation)

  → Instances of failing to comply with plant procedures, a number of which are required by the Technical Specifications

  → Instances of failing to ensure that the plant design basis is translated into specifications, drawings, procedures and instructions

  → Instances of failing to promptly identify and correct conditions adverse to quality or to preclude repetition of significant conditions adverse to quality

- Deficiencies (continued)

  - → Failed to perform a valid service test of the Unit 2, 250 Vdc battery contrary to the requirements of the Technical Specifications

  - → Failed to include Unit 1 structures, systems and components within the scope of the Maintenance Rule, contrary to the requirements of 10 CFR 50.65

  - → Instances of failing to comply with the Technical Specifications regarding the control of high radiation areas

  - → Instances of failing to comply with 10 CFR Part 20 regarding the performance of required radiation surveys and maintaining control of radioactive material

- Deficiencies (continued)

  → Instances of failing to comply with the requirements of 10 CFR 50.59 regarding the performance of safety evaluations

  → Instances of failing to update the Final Safety Analysis Report contrary to the requirements of 10 CFR 50.71(e)

  → Failed to test one safety-related valve in accordance with the requirements of Section XI of the ASME Code and the Technical Specifications

  → Instances of failing to comply with the Technical Specifications regarding the control of work hours

- Unresolved items: Items for which additional information is required to ascertain whether the items are acceptable or deficient

  → Acceptability of excluding a high pressure coolant injection system motor-operated valve from the scope of the Generic Letter 89-10 testing program

  → Acceptability of reliability measures for standby systems within the scope of the Maintenance Rule

  → Acceptability of emergency core cooling system safety-related relief valve setpoints

  → Acceptability of nitrogen inerting system flow capability

- Unresolved items (continued)

  → Acceptability of not considering instrument inaccuracy in emergency core cooling system test acceptance criteria

  → Acceptability of a replacement circuit breaker for the high pressure coolant injection system gland seal leak off condenser hotwell drain pump motor

PROBABLE ROOT CAUSES OF SIGNIFICANT FINDINGS

- Root Cause 1

Until recently, corporate and site management were not fully focused on correcting long-standing or recurring problems. As a result, only some previously identified issues were corrected. For other problems, corrective actions are still in the process of being implemented, or the corrective actions taken have not been effective in preventing recurrence. In some areas, particularly design engineering, existing performance problems had not been recognized or they had not been fully assessed for significance.

PROBABLE ROOT CAUSES OF SIGNIFICANT FINDINGS

- Root Cause 2

Corporate management did not provide meaningful oversight of or involvement with the architect/engineers to assure appropriate design control of design calculations. The licensee did not fully appreciate the impact of the growing population of design calculations and the implications associated with the failure to update them. Eventually this practice was institutionalized by procedure and engineering judgment was used to compensate for this lack of control. This acceptance by corporate management led to the further degradation of the design control of calculations. Weak quality assurance audits over the years failed to identify this problem, which has now been manifested at the site as the result of the transfer of the design engineering function to Dresden Station.