U.S. NUCLEAR REGULATORY COMMISSION

OFFICE OF NUCLEAR REACTOR REGULATION

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Licensee:	Centerior Services Company
Facility:	Perry Nuclear Power Plant, Unit 1
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EXECUTIVE SUMMARY

From February 17 through March 27, 1997, the staff of the U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Reactor Regulation (NRR), Special Inspection Branch, conducted a design inspection at Perry Nuclear Power Plant, Unit 1 (PNPP-1). The inspection team consisted of a team leader from NRR and five contractor engineers from Stone & Webster Engineering Corporation (SWEC).

The purpose of the inspection was to evaluate the capability of the selected systems to perform the safety functions required by their design bases, the adherence of the systems to their design and licensing bases, and the consistency of the as-built configuration and system operations with the updated safety analysis report (USAR). For the purpose of this inspection, the team selected the high-pressure core spray (HPCS) and emergency closed cooling (ECC) systems, on the basis of their importance in mitigating design-basis accidents (DBAs) at PNPP-1. In particular, the inspection focused on the safety functions of these systems and their interfaces with other systems.

For guidance in performing the inspection, the team followed the applicable engineering design and configuration control portions of Inspection Procedure (IP) 93801, "Safety System Functional Inspection"(SSFI). The team reviewed portions of the plant's Updated Safety Analysis Report (USAR), design-basis documents, drawings, calculations, modification packages, surveillance procedures, and other documents pertaining to the selected systems.

The team identified the following issues, some of which challenged the capability of the systems to perform their complete scope of design basis accident mitigation actions. Where appropriate, the licensee took immediate corrective or compensatory actions to ensure system operability.

- The licensee changed the ECC surge tank sizing basis from a 7-day supply to a 30-minute supply, with operator actions required outside the control room to initiate makeup from the emergency service water (ESW) system. The team concluded that this change constitutes a potential unreviewed safety question, as defined in Title 10, Section 50.59, of the *Code of Federal Regulations* (10 CFR 50.59) since the probability of occurrence of a malfunction of equipment important to safety was increased. As a result of this change, operators could incur a calculated total radiological exposure of approximately 12 rem within the first 90 minutes following a DBA. Additionally, the safety evaluation that supported the change did not adequately assess the potential for operator error, or surge tank overpressurization and adjacent area flooding when makeup from the ESW system fills the tank water-solid.

- The operation of the suppression pool cleanup (SPCU), essentially on a continuous basis, is not consistent with the facility description presented in the USAR and is not supported by a safety evaluation. Operation in this mode does not support the net positive suction head (NPSH) evaluations specified by Regulatory Guide (RG) 1.1, as presented in the USAR. This condition has existed since initial licensing of PNPP-1, as a result of insufficient analysis and corrective actions in resolving design deficiencies concerning improper

connection of SPCU piping downstream of the HPCS suppression pool suction valve rather than upstream. The HPCS/SPCU system interface design and an additional issue regarding application of pipe crack criteria (rather than pipe break criteria) to nonsafety, non-seismic, moderate-energy piping systems were referred to the NRC staff for further review.

- The actual droop setting of the Division III emergency diesel generator (EDG) deviates from the vendor's recommended setting and constitutes an undocumented modification. The team was concerned with the treatment of droop bias with respect to Technical Specification (TS) acceptance criteria and the effect on end user mechanical equipment. When droop is considered as a bias, HPCS pump surveillance test results do not meet design flow requirements for all accident situations.

- The HPCS and reactor core isolation cooling (RCIC) suction piping and the condensate storage tank (CST) instrument lines installed between the CST and the concrete containment dike are not adequately protected against external missiles, and the licensee's protective provisions were not consistent with the USAR description. On the basis of this team finding, the licensee determined that the HPCS and RCIC suctions from the CST were inoperable, and they realigned the systems to the suppression pool. In addition, the licensee instructed plant operators to maintain HPCS and RCIC suctions aligned to the suppression pool until the issue could be resolved.

In addition, the team identified the following issues which indicated programmatic deficiencies:

- The team identified deviations from licensing commitments regarding present and past testing/inspection and cleaning of the HPCS room cooler.

- Inconsistencies exist in the plant's design and licensing bases, with regard to ECC surge tank makeup and monitoring; passive single failure definitions; and application of pipe crack criteria (rather than pipe break criteria) to nonsafety, non-seismic, Category 1, moderate-energy piping outside containment.

- In several instances, the licensee had difficulty in retrieving design-basis information. This concern contributed to the licensee's inappropriate "use-as-is" disposition of plant hardware problems concerning the lack of overfrequency protection for the HPCS pump and inadequate protection of exposed equipment against the effects of tornado missiles.

- The team identified weaknesses in the licensee's development and control of calculations, as well as the review and approval processes. These included selection of incorrect codes prescribed by the American Society of Mechanical Engineers (ASME) for evaluation of the HPCS overfrequency protection relay removal and ECCS heat exchanger tube wall thickness. Other weaknesses included non-conservative system modeling regarding overpressure protection, flooding analysis, and system performance associated with the ECC surge tank; and non-conservative assumptions in the HPCS vortex and NPSH calculations. Within the electrical area, the licensee did not adequately maintain design-related

calculations in accordance with Nuclear Engineering Instruction (NEI) 0341, "Calculations." Moreover, in some cases, the calculations were inconsistent with the USAR.

- The team identified test control weaknesses. For example, analyses of test results for valve leakage at the interface between the ECC and nuclear closed cooling (NCC) systems failed to adjust measured leakage rates for predicted accident system pressures. In addition, when the licensee used testing to verify calculation assumptions, feedback of test results to close out calculation assumptions was not always timely.

During the course of the inspection the licensee documented many of the issues in their corrective action program. The number and nature of the items documented on potential issue forms (PIFs), represented very good sensitivity regarding problem identification.

III. Engineering

E1 CONDUCT OF ENGINEERING

E1.1 Inspection Scope and Methodology

The primary objectives of the design inspection at Perry Nuclear Power Plant, Unit 1 (PNPP-1), were to evaluate the capability of the systems to perform their safety functions required by design bases and to verify whether the licensee, Centerior Services Company, has maintained the plant in compliance with its design and licensing bases. As the subject of this inspection, the staff of the U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Regulation (NRR), selected the high-pressure core spray (HPCS) and emergency closed cooling (ECC) systems, because of their importance in mitigating design-basis accidents (DBAs) at PNPP-1. In particular, this inspection focused on the safety functions of the selected systems and their interfaces with other systems throughout the plant. For guidance in performing the inspection, the team followed the applicable engineering design and configuration control portions of Inspection Procedure (IP) 93801, "Safety System Functional Inspection" (SSFI).

Appendix A identifies the open items and issues resulting from this inspection, while Appendix B lists the individuals who attended the exit meeting on April 22, 1997. Appendix C lists the documents reviewed by the team, and Appendix D defines the various acronyms used in this report

E1.2 High-Pressure Core Spray (HPCS) System

E1.2.1 System Description and Safety Function

The HPCS is an emergency core cooling system (ECCS) capable of providing coolant at either high or low reactor pressure. The system is initiated in response to either low reactor water level (level 2) or high drywell pressure. The HPCS system maintains the reactor vessel water level above the top of the active fuel for small-break loss-of-coolant accidents (LOCAs). Cycling the HPCS injection valve at high and low reactor water levels controls the reactor vessel level.

For larger breaks that result in reactor depressurization, the HPCS works in conjunction with other ECCS equipment and provides spray cooling of the core. The system includes a motor-driven centrifugal pump that takes suction from either the condensate storage tank (CST) or the suppression pool. The suppression pool provides the water supply for continuous operation of the system, and suction from the CST automatically transfers to the suppression pool when the CST water supply is exhausted or when the suppression pool level is high.

The HPCS system also serves as a backup to the reactor core isolation cooling (RCIC) system in the event that the reactor becomes isolated from the main condenser and feedwater flow is lost during operation.

As designed, the suppression pool cleanup (SPCU) system interfaces directly with the HPCS, taking suction from the HPCS suppression pool suction line between the containment isolation valve and the pump. Therefore, during SPCU system operation it is necessary to align the HPCS system suction to the suppression pool (instead of the CST, as described in the Updated Safety Analysis Report (USAR)).

The HPCS system operates using normal offsite auxiliary alternating current (AC) power or power provided by its own Division III emergency diesel generator (EDG). This EDG is designed to achieve its rated speed within 13 seconds, and the HPCS system is designed to achieve its rated flow within 27 seconds.

E1.2.2 Mechanical

E1.2.2.1 Scope of Review

In evaluating the mechanical design of the HPCS system, the team reviewed the basic system design as depicted in plant documents. Specifically, the team reviewed sections of the USAR, technical specifications (TS), plant procedures, General Electric (GE) system specifications, calculations, piping and instrumentation diagrams (P&IDs), physical drawings, training manuals, maintenance records, inservice inspection (ISI) records, and setpoint data packages. In addition, the team assessed the capability of system equipment to perform its intended functions. The review also included a system walkdown, during which the team witnessed a system test in the control room and conducted interviews with the system engineer, design engineers, and control room personnel.

E1.2.2.2 Findings

a. HPCS Functions

PNPP uses a "Design-Basis Documentation Hierarchy" desk guide to identify sources of information to define and maintain the current design consistent with the plant's design bases. This desk guide cautions the user to verify the accuracy of any information contained in plant-related documents. As of this inspection, the licensee had not yet generated design-basis documents (or the equivalent) for the PNPP systems.

To facilitate the inspection process, the team requested that the licensee identify the functions of the HPCS system. The licensee described the HPCS functional design bases through references to multiple GE design specifications, the USAR, the process flow diagram, a station blackout (SBO) technical assignment file, and HPCS design change packages (DCPs). Together, these

references identified a variety of HPCS functions, including core cooling to prevent fuel damage for large- break LOCAs, core makeup water for small-break LOCAs, backup for RCIC, SBO makeup water to the vessel, and support of various transients and accidents (identified in Chapter 15 of the USAR) including anticipated transient without scram (ATWS).

b. CST Volume Design Basis

GE Design Specification 22A3131AD, "High-Pressure Core Spray," Revision 6, Requirement 4.3.1, states that each boiling-water reactor (BWR) unit must maintain a condensate water storage reserve of 150,000 gallons. The team requested that the licensee provide the design basis for the GE-imposed 150,000 gallon requirement, since the basis was not apparent. In response, the licensee contacted GE, and GE indicated that the required volume reflected the water inventory makeup required for RCIC to remove reactor decay heat during the first 8 hours following reactor shutdown, assuming that the safety relief valves (SRVs) maintain reactor pressure. The HPCS system is classified as a backup system to RCIC; therefore, requirements applicable to RCIC also apply to HPCS. The CST is classified as a nonsafety-related source of water and, consequently, is not credited for accident mitigation.

c. NRC Bulletin 96-03, ECCS Suction Strainers

On May 6, 1996, the NRC issued Bulletin 96-03 to all operators of nuclear power plants. Specifically, this bulletin warned the operators of potential plugging of emergency core cooling suction strainers by debris. In the bulletin, the NRC staff identified three options to resolve this issue, including installation of a large-capacity passive strainer, a self-cleaning strainer, or a backflush system.

In its response to the NRC Bulletin, PY-CEI/NRR-2111L, dated November 4, 1996, Cleveland Electric Illuminating (CEI) stated that some events could block the ECCS strainers at PNPP-1 with insulation from the drywell. This blockage will result in an insufficient net positive suction head (NPSH) for the ECCS pumps, leading to subsequent failure to meet the core cooling requirements. To address this problem, CEI proposed to install a large passive strainer design (Bulletin 96-03 option 1), which is a floor-mounted strainer that circles the suppression pool. CEI intends to install the new strainer during the next refueling outage (fall 1997). The licensee's corrective action for this issue appears to be appropriate, and implementation of the licensee's corrective actions is being controlled through the bulletin commitments.

d. Review of HPCS System Vortex Formation While Aligned to the CST

Calculation P11-12, "P11 - Level Setpoints in Condensate Storage Tank for E22 and E51 Instruments" dated March 12, 1985, determined the CST low-level swapover setpoint required to ensure that the HPCS system has adequate NPSH and that no vortex occurs before suction valve swapover to the suppression pool. The team reviewed this calculation and identified the following concerns:

- The licensee based the calculation on a flow rate of 700 gpm for RCIC and 1550 gpm for HPCS, as substantiated by P&ID D-302-012, "Condensate Transfer and Storage System." The licensee combined the HPCS and RCIC flows since both would be taking a suction from the CST through a common line. The team questioned the licensee's use of the 2250 gpm flow rate for calculating CST suction line vortex value since a higher flow rate would be a worst case. Operating data on the referenced drawing and in the GE Design Specification 22A3131AS, Revision 3, specifies a maximum HPCS flow rate of 6110 gpm at 200 psi backpressure in the reactor vessel and 7800 gpm at runout flow. The team also confirmed that HPCS Process Diagram 4549-20-001, Revision 9A (USAR Figure 6.3.1), "Accident, System Injection at Rated Core Spray, Suction from CST," specified the same high-flow requirements for HPCS.

- Additionally, the CST water level setpoints did not address continued drawdown of the CST as the transfer from the CST to the suppression pool takes place. HPCS suction from the CST continues as the suppression pool suction isolation valve first strokes open, and the CST suction isolation valve then strokes closed.

On the basis of the team's concerns, the licensee issued Potential Issue Form (PIF) 97-0416. The engineering evaluation on the PIF indicated that the licensee had previously evaluated the adequacy of the swapover setpoint as part of the system-based instrumentation and control inspection (SBICI) in 1995, and found it to be acceptable. In resolving the issue in 1995, the licensee stated that the primary function of HPCS was to alleviate the consequences of a small line break, when the reactor is at pressure and the required HPCS flow is 1550 gpm. For a large-break LOCA during which the HPCS will deliver full flow, the licensee contended that suppression pool swell caused by the LOCA will lead to a transfer of suction to the suppression pool as a result of the suppression pool high-water level swapover setpoint. However, the licensee could not identify design-basis documentation that would substantiate the assertion that pool swell negated the need for the CST level to cause the suction swap during high-flow conditions, as specified in the GE design documentation. The licensee further indicated that startup tests, performed at a flow rate of 7200 gpm and a CST level 2 feet below the current setpoint, verified that no vortex formed before swapover to the suppression pool.

The licensee revised the calculation using a HPCS flow rate of 6110 gpm; however, the team questioned the revised calculation, since the licensee did not include RCIC flow. Ultimately, the licensee revised the calculation to consider valve stroke time and the worst-case pump runout flow of 7200 gpm. To support the current setpoint, the licensee had to use a less conservative methodology, which considers operation in the region where vortex formation is possible. In so doing, the licensee found that air could enter the pipe and travel 380 feet inside the pipe, but the air would not reach the pump before swapover to the suppression pool. The licensee did not change the current setpoint level as a result of the revised analysis.

10 CFR Part 50, Appendix B, Criterion III states that the design control measures shall provide for verifying or checking the adequacy of the design. The licensee's Operations Quality Assurance

Program, USAR 17.2 commits to compliance with Regulatory Guides and Standards as listed in USAR Table 1.8-2. USAR Table 1.8-2 commits to following ANSI45.2.11 - 1974 for Quality Assurance Requirements For The Design of Nuclear Power Plants. Nuclear Engineering Instruction NEI-0341 Revision 5 "Calculations" applies to all calculations to establish design bases or to change design documents. Paragraph 6.2, Calculation Revisions states "Design Engineer are to monitor calculations to determine if a revision is required e.g. receipt of new/revised design input, confirmation of assumption etc.". Paragraph 6.3 Review and Approval states "Verification/review and approval of calculation should precede use of the results for design, but must be completed prior to the component, system, or structure being declared operable."

The team concluded that the licensee's use of non-conservative flow rates and not considering the impact of valve timing within the original calculation to resolve the issue in 1995 were inappropriate. The licensee used nonconservative modeling of HPCS flow at 6110 gpm and did not include RCIC flow in their initial response to the team's concern. The final calculation which used HPCS pump runout flow was the appropriate value. These issues represent a weakness with respect to Criterion III, "Design Control," established in Appendix B to Title 10, Part 50, of the *Code of Federal Regulations* (10 CFR Part 50). Additionally, the team questioned the licensee's basis for not resetting the CST low-level setpoint to provide a margin and preclude the entry of vortexing into the pipe. Consequently, the team identified this item as Unresolved Item (URI) 50-440/97-201-01.

e. HPCS Pump Net Positive Suction Head (NPSH)

The team reviewed Calculation E22-1, "NPSH Calculation—HPCS System with DCC-02," Revision 0, to verify that the licensee had fulfilled all NPSH-related requirements defined in USAR Table 6.3-1. The team verified that the calculation used the correct pump runout flow (7800 gpm), containment pressure (0 psig), maximum pool temperature (212°F), maximum CST temperature (120°F), suppression pool water level (589 feet), suction strainer clogging (80% plugged with 9.2-foot pressure drop), and equipment elevation. However, the calculation did not consider the operation of the SPCU system (as discussed in Section E1.2.5.2 of this report) and had to be revised in order to demonstrate acceptable HPCS NPSH.

f. Keep-Full Pump

Test results for the HPCS keep-full pump (from TXI-229, dated March 19, 1996) showed that the pump was not capable of delivering the 40 gpm flow at 32.5 psi pressure specified in USAR Section 6.3. The pump delivered 32.4 gpm flow at 34.5 psi which equates to a value less than specified in the USAR. This degraded condition has existed since July 24, 1993, when the surveillance test was conducted. After identifying this condition, the licensee issued PIF 96-1609, which requested evaluation of this condition, as well as establishing new USAR acceptance criteria. The licensee considered the pump operable even though it was not capable of meeting USAR flow and pressure values.

The licensee indicated that, even though the keep-full pump was degraded, it was capable of maintaining system pressure above the alarm setpoint. The licensee further indicated that, if the alarm is received, operators would attempt to raise system pressure in accordance with Alarm Response Instruction (ARI) H13-P601-16, Revision 4. If unsuccessful, they would confirm that the system is filled by checking its fill status (SVI-E22-T1183) every 24 hours or by performing SOI-E22A, "HPCS High-Point Vent." The licensee had not determined the rate of discharge line pressure decay when the pump is not operating. Consequently, the arbitrary time period of 24 hours may exceed the time at which voids are introduced in the system. To address this issue, the licensee issued PIF 97-0513, documenting that if the keep-full pump was inoperable, performing the SVI once every 24 hours may not account for a pressure decay and may create voids in the pipe.

The team concluded that the degraded condition of the keep-full pump since 1993 represents untimely corrective action to resolve the condition or revise the USAR. Consequently, the team identified this issue as URI 50-440/97-201-02.

g. Suction Relief Valve

The HPCS suction relief valve relieves suction pressure by directing flow to the dirty radwaste system that is *outside* containment. This design deviates from GE Specification 22A3131, Revision 5, Section 4.2.3.15, which specifies that the pump suction pressure relief valve should relieve to the suppression pool *inside* containment.

During construction, the applicant issued Field Deviation Disposition Request (FDDR), KL1-4006, dated September 15, 1983, stating that from an HPCS standpoint, this new route would not degrade the safety or reliability of the HPCS system. Although the disposition included evaluation of potential water inventory loss from the suppression pool, the licensee failed to document 10 CFR Part 100 release consequences. The licensee stated that an unacceptable radiological release from a failure of the relief valve was not considered credible. Since, for a small-break LOCA when the HPCS suction may be pressurized by back-leakage from the reactor as the HPCS cycles, no fuel damage was postulated in accordance with 10 CFR Part 100. For large breaks with the reactor depressurized below 100 psi, back-leakage from the reactor vessel will not cause pressurization to the relief valve setpoint. The licensee issued PIF 97-351 to document the lack of traceable documentation as to the acceptability of this deviation from the design specifications. The team considered the licensee's review of this issue acceptable and that this was a case where the licensee did not adequately document the design basis of the relief valve and the acceptability of the deviation.

h. Pump Performance/Surveillance Testing

On February 20, 1997, the team witnessed system surveillance test SVI-E22-T2001, which verified that the HPCS pump is operable by measuring and verifying that the listed pump parameters are within acceptable limits. This test satisfied the HPCS pump operability

requirements of Technical Specifications 3.5.1.4 and 3.5.2.5, and included measurements of suction pressure, differential pressure, flow rate, and vibration.

The pump fulfilled its test acceptance requirements and satisfied the vendor's performance curve. In addition, the team reviewed historical records of surveillance testing, which demonstrated that the equipment typically passed its acceptance criteria and when problems have been noted, the licensee had initiated appropriate corrective actions.

i. Motor-Operated Valves—GL 89-10

To verify whether the licensee fulfilled the commitments expressed in response to Generic Letter (GL) 89-10, the team reviewed a sample calculation performed as part of the commitment program. The sampled calculation, MOV C-0047, "AC Voltage Drop Calculation for Butterfly MOVs," Revision 3, was performed to determine worst-case motor terminal voltage for the AC-powered safety-related butterfly motor-operated valves (MOVs). The resulting voltage values were later used in another calculation to determine the torque output of the butterfly MOVs. On the basis of this review, both the calculation and the final determination were considered adequate. Item j (below) discusses the effect of the GL 89-10 program on the HPCS injection valve.

j. Injection Valve Stroke Time

USAR Table 6.3-1 requires the HPCS system to inject at rated flow within 27 seconds. Related tests record three intervals following a LOCA signal, including the time for the Division III diesel generator to start and reach rated RPM, the time for the injection valve to reach the full- open position, and the time for the pump to reach rated flow. The tests do not individually evaluate the valve opening time and the time required for the pump to reach full flow, but these intervals are added to diesel start time and are acceptable if the total time is within the required 27 seconds. The opening time for the injection valve is allowed to reach 29 seconds, since the valve is opened sufficiently at 27 seconds to allow rated flow to the reactor.

Records of previous valve injection tests showed that the overall time interval was within the allowable limit, such that even if each time interval would have been separately evaluated (not benefitting from the short diesel start time), it would still have passed its respective acceptance criterion.

k. HPCS Testing Mode Operation

GE Design Specification Data Sheet 22A3131AS and USAR Section 6.3 specify that the HPCS must deliver rated flow to the reactor within 27 seconds after receiving an initiation signal. From the normal operation standby condition, this requires the HPCS injection valve to stroke open and develop the rated flow to the reactor within the 27-second time constraint. The team reviewed the ability of the HPCS to perform its safety function under the full-flow testing mode of

operation. Specifically, while in the test mode of operation HPCS valve realignment would be necessary in order to establish injection flow to the reactor. Test valves aligned in the test mode receive closure signals upon HPCS initiation to realign the HPCS for injection to the core.

The licensee had previously noted that the stroke times for the test valves would not support realignment and the 27-second injection time. In particular, Surveillance Procedure SVI-E22-T2001 allows test valve closure times of 60 to 80 seconds, depending on valve size. These stroke times exceed the 27-second time constraint for the HPCS to reach rated flow and indicate that the HPCS cannot be considered operable when it is in the test mode configuration.

Surveillance Instruction SVI-E22-T2001, "Precautions and Limitations," indicates that the HPCS should be operated in accordance with SOI-22A. Revision 5 of SOI-22A, effective June 28, 1995, requires that the HPCS must be declared inoperable (in accordance with a standing instruction dated March 8, 1995) whenever it is in a secondary mode of operation. Before March 8, 1995, there had been no directives to declare the HPCS inoperable during full-flow testing.

After recognizing that the HPCS was inoperable while in the test mode the licensee's investigation failed to determine if other equipment (RCIC, LHSI, LPCS, etc.) was operable as required by TS when HPCS is inoperable. If the related equipment was inoperable while HPCS was inoperable because of testing the plant could have been operating in violation of TS. The licensee issued PIF 97-0560 to investigate concerns regarding past operability of other systems during HPCS test performance to determine if the plant had been operated in accordance with the TS.

The team concluded that while undergoing full-flow testing, the HPCS could not reach rated flow within 27 seconds of HPCS initiation because of the slower closure of test valves diverting HPCS injection flow from the reactor. This condition has existed since the initial operation of PNPP-1. The licensee recognized this operability condition in 1995. Resolution of PIF 97-0560 will determine if a TS violation has occurred during HPCS testing for the period from plant startup to the issuance of the standing order in 1995. The team identified this issue as URI 50-440/97-201-03.

I. Overfrequency Protection Relay Removal/System Overpressure Protection

GE Design Specification 22A3131, Revision 5, Requirement 4.4.10, specified that the main HPCS pump circuit breaker shall automatically disconnect the pump motor load if the electrical bus frequency exceeds 105% of the rated frequency. This specification provides HPCS discharge piping overpressure protection, as required by Section III of the American Society of Mechanical Engineers (ASME) Code. However, during construction of the PPNP-1, the architect/engineer (AE) decided not to install the HPCS pump motor overfrequency protection relay, on the basis of FDDR KLI-3890, dated May 28, 1985. The licensee's SSFI of the HPCS system in 1992, recognized that the basis for not installing the relay identified in the FDDR was not well founded. Consequently, the licensee performed Calculation E22-19, "Justification for Elimination of HPCS

Overfrequency Relay," Revision 1, dated July 23, 1992, to evaluate the effect of not installing the relay. The team reviewed this calculation and identified the following concerns:

- The licensee's calculation referenced Section III, NB-3654.1, of the ASME B&PV Code in order to justify exceeding the system design pressure by 10% in the event that the Division III EDG frequency goes above 60 Hz. The licensee's calculation did not identify the specific edition or addenda of the Code that was used to justify their decision not to install the overfrequency/overpressure protection relay. Design Specification (DSP) E22-1-4549-00, Revision 3, dated April 18, 1986, referenced that the 1974 ASME B&PV Code with addenda up to and including the winter 1975 issue, was the applicable Code for this system. Section NB-3654.1 of the 1974 Code did not apply to overpressure allowance and was the wrong reference. Although the 1974 Code did contain a provision for overpressure allowance in NC-3612.3 the NB portion did not contain a similar allowance. It was inappropriate for the licensee to apply this current **NB** code reference to the entire discharge piping from the pump to the reactor vessel since **NC** portions of the Code applied to equipment within this boundary. Additionally, the licensee did not evaluate the overpressure condition on components within the boundary.

- The licensee's calculation methodology provided a relief path to limit pressure using the minimum flow valve and its actuation circuitry as overpressure protection devices. The team questioned the licensee's use of this equipment for overpressure protection since compliance with the requirements with ASME Code Section III, Article NC-7000, "Protection Against Overpressure," could not be demonstrated for this valve and its actuation circuitry.

- The licensee's design control process requires that the NSSS review modification and engineering decisions that affect system still under their design authority. Based on the information reviewed by the team it was not evident that GE reviewed or approved the final design.

The licensee issued PIF 97-0575 to document concerns regarding the overfrequency protection relay removal calculation and to justify continued operability. The team determined that the calculation methodology, code application, and review/approval process did not ensure design quality as specified in the USAR Section 17.2, QA program and 10 CFR Part 50, Appendix B, Criterion III, "Design Control." The licensee stated that they would reevaluate the possible need to install the overfrequency relay as part of the effort to resolve PIF 97-0575. Additionally, the team determined that the licensee's improper disposition of the 1992 discovery of this issue constitutes ineffective 10 CFR Part 50, Appendix B, Criterion XVI, corrective action. Consequently, the team identified this issue as URI 50-440/97-201-04.

m. Fuel Oil Storage Tank Chemistry/Water Removal

To verify that the fuel oil storage tank undergoes periodic water removal and chemistry analysis, the team reviewed SVI-R45-T1323, dated January 15, 1997, and RPI-1103, dated January 24, 1997. The team also reviewed the history of water removal and chemistry analysis and determined that little or no water has been detected in the tank's sump, and the chemistry analysis results of the oil have been acceptable.

n. Testable Rupture Disc

The testable rupture disc (TRD) on the safety-related exhaust of the Division III EDG is designed to provide pressure relief in case the nonsafety-related portion of the exhaust or silencer is blocked, restricted, or inoperable. The team reviewed the design of the disc as depicted by Drawing D-301-801, Revision A; Calculation R48-8, "EDG Exhaust Vent Valve Size," Revision 1; Calculation R48-11, "Standby and HPCS DG Exhaust Vent Valve," Revision 2; Calculation R48-17, "Seizure of EDG Exhaust Vent Valve Bearings," Revision 0; and Calculation R48-13, "EDG Exhaust Vent Valve Setpoint Calculation (with DCC-003)," Revision 0.

Through this review, the team determined that the disc is not tested during diesel operation when realistic operating temperatures and pressures are present. The disk is tested using a test device to measure the force necessary to lift the disk. This test force is calculated using area of the disk and allowed back-pressure that should cause the dist to lift. The design of the disc is sensitive to temperature differential across the disc and the resulting displacement of the locking mechanism. Also, the disc is susceptible to warping, which causes fluctuations in the amount of force required to open the disc.

During the test on February 19, 1997, the Division III disc lifted at 750 lbs force. At a diameter of 30 inches, this translates to 29.4" water gauge (WG), which was greater than the allowable exhaust pressure of 10" WG. For this test failure and similarly times when the disc has opened with a force greater than the allowable, the licensee identified the problem as being related to testing and did not determine that the disc and the diesel may have been inoperable. In one case, where the disc was locked closed, the licensee determined that the EDG was inoperable.

The team identified that the TRD test and operational failures appeared to be design related. Additionally, the team considered that the licensee's corrective actions were deficient, since TRD reliability problems appear repetitive. There have been more than 12 failures to date, more than 6 years after the first failure to open, and almost 12 years after the disc opened too early. The licensee's corrective actions have not resolved the problems.

The team questioned the basis for the TRD setpoint value specified in the test procedure. In response, the licensee stated that numerous vendor letters have provide conflicting values for acceptable EDG back-pressure. In a letter from Engine Systems, Inc. dated October 15, 1996,

the engine vendor published a maximum back-pressure value of 5" WG. GE the NSSS, allowed a maximum back-pressure value of 10" WG. The licensee also indicated that another letter from MKS Power Systems(the system service rep.), dated October 13, 1995, allowed a back-pressure of 15" WG during a transient, which equates to an engine power reduction of 0.5%. This value was later translated to 18.5" WG at the location of the TRD and was used to reevaluate high lift forces experienced during testing.

The licensee established the allowable back-pressure value of 10" WG using the assumption that, during EDG operation, the nonsafety-related exhaust may become blocked, causing a back-pressure sufficiently high to open the safety-related exhaust equipped with the TRD. However, the nonsafety-related exhaust may become blocked *before* the diesel engine starts. In that case, a high back-pressure may prevent the engine from starting. The licensee had no documentation from the vendor to justify that the back-pressure setpoint for the TRD would be acceptable for both situations. At the conclusion of the inspection, the licensee had not obtained vendor verification that the current setpoint was acceptable for both situations.

The licensee is currently testing the Division III TRD every month until repeatable data demonstrate that the TRD is reliable. The root cause evaluation for PIF 97-0325, which documented the latest failure of the Division III EDG TRD, identified that the TRD design is the most likely cause of the numerous failures. Additionally, the root cause identified that previous corrective actions have been ineffective in preventing failure recurrence and improving reliability. The licensee indicated that a TRD design modification was considered in 1990, but was never implemented. However, because of recent failures, the licensee now plans to implement the design modification during operating cycle 7.

10 CFR Part 50, Appendix B, Criterion XVI, requires that conditions adverse to quality (such as failures, malfunctions, deficiencies) must be promptly identified and corrected. However, to date, the licensee's actions have not been timely or effective in ensuring reliable operation of the EDG TRD. Consequently, the team identified this issue as URI 50-440/97-201-05.

E1.2.2.3 <u>Conclusions</u>

The team concluded that the mechanical design of the HPCS system was generally acceptable, and the system was capable of performing its safety function as evidenced by the surveillance testing reviewed, although some margins may be small. For example, the HPCS pump is sequenced onto the emergency bus during a loss of off-site power at a bus voltage of 75% in order to meet the required injection times. During surveillance full-flow testing the HPCS system is inoperable because of test valve design (50-440/97-201-03). The current HPCS suction swapover setpoint from the CST allows air to travel into the suction pipe (50-440/97-201-01). Additionally, as discussed in Sections E1.2.3.3.a and E1.2.5.2 of this report, EDG operation in speed droop and continuous operation of the SPCU system further impact the margins associated with HPCS flows and timely delivery of water into the reactor vessel. Other findings indicate that a lack of rigor exists in the licensee's documentation and understanding of the design bases, and

maintenance of the design- and licensing-basis configuration (50-440/97-201-04). Additionally, resolution of the Division III EDG TRD testing failures was not timely (50-440/97-201-05).

E1.2.3 Electrical

E1.2.3.1 Scope of Review

The team reviewed the electrical design for normal and emergency operation of the HPCS pump motors, selected MOVs, circuit breakers, fuses and interlocks. The team also compared the design drawings to the system description manual (SDM), as well as applicable sections of the USAR, TS, and surveillance test procedures (SVIs), in order to verify consistency among the documents. In addition, the team reviewed the calculations related to voltage drop, electrical loading, and coordination of selected HPCS components and associated electrical components. In conducting this review, the team sought to determine the adequacy of the available voltages, equipment loading, protective system coordination, and electrical isolation and independence.

E1.2.3.2 System Description and Safety Function

The station's direct current (DC) system supplies power to plant instrumentation and controls under all modes of plant operation. In addition, upon loss of AC power, the DC system provides power for emergency lighting and turbine generator auxiliary loads. Batteries, battery chargers, and distribution equipment for the Class IE 125-V DC system are located in separate rooms in a seismic Category I structure.

No interdivisional ties are provided between the divisions associated with Unit 1 or Unit 2. Maintenance tie buses connect only the same divisions of the two units. In addition, maintenance tie bus circuit breakers are normally open and are manually operated under administrative control. They permit isolation of the battery and normal battery charger associated with either Unit 1 or Unit 2 for maintenance or equalization of the battery.

The Class IE, Division I and Division II 125-V DC system batteries are sized to supply the required DC loads for a minimum of 2 hours without the final discharge voltage decreasing to less than the design minimum of 1.75 volts/cell. The 125-V DC system and the associated loads and controls supplied by the 125-V DC system are designed to operate from 140 V DC (maximum corrected equalizing charge of 2.33 volts/cell) to 105 V DC (rated discharge to 1.75 volts/cell).

The Division III 125-V DC power system provides a continuous, independent 125-V DC source of control and motive power, as required for HPCS system logic, HPCS diesel generator control and protection, and all Division III-related 125-V DC controls. It includes a 60-cell, lead calcium battery (100 ampere hours at 8 hours), and battery chargers. The Division III 125-V DC system is classified as Class IE. The system is independent of all other divisional batteries, and there is no manual or automatic connection to the Division I or II battery systems. A manually operated

maintenance tie between the Unit 1 and Unit 2 Division III DC systems is provided for maintenance or equalization of the battery.

E1.2.3.3 Findings

The team verified that the HPCS is powered from a separate emergency power bus and that the licensee considered the electrical loading of the individual components in the Division III EDG capacity calculations. The sequence and timing for loading the HPCS pump and valves onto the EDG was consistent with the USAR.

The system design documents reviewed by the team adequately supported the design, except for the discrepancies and open items discussed in the following paragraphs.

a. HPCS Diesel Generator Droop Setting

The Division III diesel generator (DG3) is the emergency source of power for Bus EH13. Bus loads consist of the HPCS pump, valves, and auxiliaries. DG3 is designed to operate in the isochronous mode (i.e., as the sole supplier of power to the bus) when the bus is isolated from the grid, and in the parallel mode when the bus is tied to the grid during testing.

The diesel starts upon receipt of a LOCA initiation signal, and the generator connects to an isolated EH13 bus. Loads (such as MOVs) are permanently connected to the bus and operated in turn as dictated by the startup and operating sequence of HPCS. The HPCS and emergency service water (ESW) pump loads are sequenced onto the bus at preset times. As the HPCS system continues to operate, load changes consist of MOV operations as the HPCS cycles between full flow to the reactor and minimum recirculation flow to the suppression pool, as determined by reactor vessel level indication. DG3 continues to operate in this isochronous mode to supply emergency power. To parallel with the grid, DG3 must be manually synchronized, with its output breaker closed while the normal bus supply breaker from offsite power remains closed.

The speed of DG3 is controlled by a Woodward UG-8 mechanical governor, and the mechanical droop setter for the governor is local to the governor. The manufacturer recommends setting the droop to zero when operating in the isochronous mode, as shown in Section 12 of the General Motors "Electro-Motive Division 6454E4 Turbocharged Engine Maintenance Manual," PNPP File 114-G. The licensee indicated that, during initial plant startup, the DG3 droop setting was kept at zero when in the standby mode. When the diesel was tested, it was paralleled to the grid after adjusting its droop setting to accommodate operation in the parallel mode. After the diesel was shut down and returned to the standby mode, the droop setting was returned to zero.

The licensee was not able to determine when the change in droop setpoint occurred but present practice at PNPP-1 is to maintain the DG3 droop setting at a value of 20 on the dial face at all times. This setting of 20 equates to -2% of rated speed when the diesel is loaded (-1.2 Hz). PNPP engineers explained that this practice was established as a convenient way to preclude the

possibility of the droop being inadvertently left set at an incorrect value. Instrument Maintenance Instruction (IMI) E3-23, Section 5.2.4, Step 23, dated June 12, 1991 (in effect at the time of this inspection) instructs plant personnel to "Reset speed droop control, if necessary, to 20." The team had the following concerns regarding the licensee's established practices:

- The diesel generator was originally qualified to Regulatory Guide (RG) 1.9, Revision 0, and the licensee was unable to locate documentation to demonstrate the qualification setting at other than the vendor recommendation of zero droop. The licensee also could not produce any documentation to support the current setpoint or the impact of isochronous mode operation at a droop setting other than zero. The licensee confirmed that no specific testing had been performed with this droop setting to revalidate the diesel generator qualification and confirm acceptable operation. USAR Table 1.8-2 commits to following ANSI45.2.11 - 1974 for Quality Assurance Requirements For The Design of Nuclear Power Plants. ANSI45.2.11 - 1974 requires that changes from specified design inputs or quality standards including the reasons for the changes shall be identified, approved, documented, and controlled. The team concluded that the change in the droop setting constituted an undocumented modification, and identified this issue as URI 50-440/97-201-06.

- In a related but separate issue, the licensee had previously issued PIF 97-0165 on January 28, 1997, to assess the impact on the mechanical systems of operating any of the diesel generators within a frequency band of ± 1.2 Hz (or ± 2% of rated speed). The licensee had not conducted any such analysis before that time. The licensee documented their review of PIF 97-0165 in a calculation that showed that, at a frequency of 58.8 Hz, the HPCS pump would be unable to develop minimum discharge pressure by 4 psig. The team noted that the calculation treated droop as a bias and added it to other errors to calculate the total loop error. The other errors (including the TS-allowed ± 2% of rated speed error) were appropriately treated as random and were statistically added. The team agreed with this approach.

  The licensee provided the inspection team with surveillance test strip charts showing performance of the diesel generator during testing with normal accident loads. In providing these test results, the licensee's purpose was to substantiate the position that the diesel generator operates within TS values at a droop setting of 20. These charts showed that, during startup and load sequencing, the voltage and frequency disturbances associated with load variations were within the tolerances specified in RG 1.9. However, because droop was set at 20, the frequency was shown to decrease as the load increased, to 59.15 Hz at a load of 2200 kW. The licensee also demonstrated that, with other loads associated with the pump operating at runout flows, the full-load projection for DG3 was 2250 kW, with a corresponding speed equated to approximately 59.1 Hz (compared to the TS lower limit of 58.8 Hz).

  The licensee modified the original position and, at the conclusion of the inspection, planned to revise the original PIF 97-0165 evaluation. The licensee stated that it was inappropriate

to add droop as a bias to the other errors in calculating the total loop error, since the TS allow EDG surveillance testing to be considered acceptable if the EDG starts and operates at 60 ± 1.2 Hz unloaded. As demonstrated by surveillance testing, droop causes the bus frequency to drop as DG3 is loaded. The licensee noted that the procedure used to shut down DG3 after testing involved reducing the load to approximately 100 kW while observing that the speed increases to slightly above 60 Hz. At this point the diesel generator is stopped. The licensee is using this administrative control to ensure that the TS would be met by setting up DG3 to start the next time at 60 + Hz. Because droop biases bus frequency approximately 2%, the team concluded that the licensee's position (that droop should not be considered as a bias added to the other errors in calculating the total loop error) was inappropriate. The licensee held discussions with GE at the conclusion of the inspection in an attempt to gain additional HPCS flow margins to allow droop to be added as a bias as originally planned. Consequently, the team identified the need to review this calculation after revision as URI 50-440/97-201-07.

b. Battery Surveillance Testing

SVI-E22-T5217, "18-Month Battery Surveillance Test Data," dated October 7, 1996, for Battery 1E22-S005 showed that individual cell voltage for Cell 60 dropped below 1.75 V to 1.32 V at the end of test (127 minutes). The licensee concluded that lower voltage for Cell 60 did not constitute an unusual situation. Institute of Electrical and Electronics Engineers (IEEE) Std. 450-1980, "Large Lead Storage Batteries for Generating Stations," Section 6.4.4, allows jumping out individual cells if the voltage begins to approach 0. This review of discharge test data indicated that this cell's capacity is in the high 90% range, well within the acceptance limits of the test. The performance of this cell, while somewhat below average compared to other cells in the battery, did not significantly affect overall battery capacity, which was verified to be 106%.

E1.2.3.4 Conclusions

The team concluded that the electrical design for components that perform the engineering safeguard functions of the HPCS was adequate and operating within the design limits. However, further analysis of droop bias effects on mechanical equipment performance is needed (50-440/97-201-07). The deviation from the vendor recommendation for DG3 droop setting without a documented basis constituted an undocumented modification (50-440/97-201-06).

E1.2.4 Instrumentation and Controls (I&C)

E1.2.4.1 Scope of Review

In evaluating the HPCS I&C area, the team reviewed design documentation, conducted interviews, and performed walkdowns of the HPCS system. The team concentrated on protective functions that maintain reactor core cooling and vessel inventory during and after a LOOP/LOCA or LOCA. In addition, the team assessed the design for the ability to meet USAR commitments

and to operate within TS limits. Attributes reviewed comprised instrument installations, instrument setpoints, instrument power and AC and DC control power provisions, and remote and alternative shutdown provisions. Documents reviewed included applicable sections of USAR Chapters 1, 3, 5, 6, 7, 8, and 9; TS; SDMs; vendor documents; P&IDs; logic diagrams; electrical wiring diagrams; instrument installation drawings; calculations; calculation change records; PIFs; action requests (ARs); condition reports (CRs); nonconformance reports (NRs); and DCPs.

E1.2.4.2 Findings

a. Missile Protection of CST Suction Piping for HPCS/RCIC and Tank Level Instrumentation

The CST is a nonsafety-related, non-seismic tank located outdoors inside a concrete dike structure. At 2 feet, 0 inches thick, and 23 feet, 8 inches high, the dike is a seismic Category I structure designed to withstand externally generated tornado missiles, and creates an annular space of 8 feet, 0 inches, between the tank and the dike wall with a capacity to retain the total inventory of the CST. A concrete room to house CST level instrumentation is provided, designed and fabricated to the same standards as the dike, and includes a labyrinth entrance for missile protection.

The CST is a source of clean water for the RCIC and HPCS systems. GE Design Specification Data Sheet 22A3131AS; Functional Control Diagrams (FCDs); CEI Drawing No. D-308-311, Sheets 1–4; the HPCS SDM E22A; and USAR Section 6.3 designates the CST as the normal source of water for the HPCS. When the water level in the CST is drawn down to the low-level setpoint, the HPCS suction lineup is transferred to draw from the suppression pool as the safety-related source of water.

Instrumentation monitoring the water level in the CST to effect the transfer to the suppression pool is safety related. Two safety-related class 1E powered transmitters (1E22-N054C and 1E22-N054G) monitor CST water level with a one out of two logic for the suction transfer.

RCIC and HPCS share a common ASME Section III suction line from the CST. This suction piping exits the side of the CST above the floor slab, bends downward 90° to penetrate the floor slab in the annular space between the CST and the dike, and is then routed underground to the Auxiliary Building.

USAR Section 3.5.1.4 states that, safety-related systems and components which are located outside of Category I structures are provided with unique missile barriers. USAR Table 3.5-7 indicates the HPCS and RCIC piping to the reserve water in the CST is underground, covered with a minimum of 4.5 feet of compacted earth for protection against external missiles. However, both the instrument sensing lines and the RCIC/HPCS suction piping are exposed inside of the dike wall and are unprotected from missiles originating from natural phenomena such as seismic events or tornadoes. During the CST walkdown, the team identified two non-seismic stacks on

the top of the Auxiliary Building that may have the potential to fall and hit the CST, CST water level instrument piping, and RCIC/HPCS suction piping.

Calculations 22:08 and 22:11 address the tornado missile design of the dike wall and document that protection from externally generated tornado missiles is provided for the instrumentation located inside of the instrument room along the dike wall. However the CST water level instrument piping and the RCIC/HPCS suction piping inside of the dike were not addressed in the calculations. Both are vulnerable to damage by either gravitational and tornado-generated missiles. The instrument lines are routed close together so that a single missile could strike both of them. In the case of the suction piping, the effect of the piping being struck by any missile would be either the loss of its pressure boundary and leakage of the CST inventory into the dike area, or crimping the line and restricting the flow. No analysis existed to substantiate the licensee's current protection of this equipment from tornado missiles.

The licensee acknowledged this finding and issued PIF 97-0561 to address the adequacy of the tornado missile and seismic protection design for the CST level instrument piping and HPCS suction piping installed between the CST and the concrete containment dike. The licensee conducted an immediate operability review for the HPCS and RCIC systems. The CST level instrument piping and HPCS suction piping installed between the CST and the concrete containment dike were considered to be inoperable. In accordance with TS 3.3.5.1 and 3.3.5.2, if the HPCS and RCIC suction valves are lined up to the suppression pool, these systems need not be considered inoperable. As a result, the licensee issued instructions to the operators to maintain a line up of the HPCS and RCIC suction valves to the suppression pool. Operation in this lineup would continue until further analysis substantiates the acceptability of the design of the CST level instrument piping and HPCS/RCIC suction piping inside of the concrete containment dike or corrective measures can be implemented to upgrade the design condition.

The licensee's initial review of the issues described in PIF 97-0561 (Calculation 1:05.7), indicated that, on the basis of probability, the equipment in question did not need to be protected. This probability of damage approach was questioned by the team since Section 3.5.1.4 of the Perry Safety Evaluation Report (SER) (NUREG-0887) used a probability of 1 that a tornado-generated missile would strike exposed equipment. During subsequent discussions the licensee informed the team that Section 3.5.1.5 of the NRC's Standard Review Plan (SRP) allowed the use of probability. Use of SRP Section 3.5.1.5 which addresses external not tornado generated missiles was not appropriate for this review. The team determined that the licensee resolution of this issue was inadequate and informed the licensee. After further review, the licensee agreed that the PIF resolution was not in accordance with their licensing bases and was therefore unacceptable. The PIF resolution effectively changed the plant from that described in the USAR and should have been supported by a safety evaluation pursuant to 10 CFR Part 50.59. PIF 97-0738 was issued and a walkdown of equipment was initiated by the licensee. The team, therefore, informed the licensee that the current missile protection design for equipment subjected to tornado-generated missiles was effectively a change to the plant from that described in the USAR and represented a

potential unreviewed safety question. In addition, the team identified this issue as URI 50-440/97-201-08.

b. Condensate Storage Tank Low-Level Instrumentation

The two safety-related CST low-level transmitters are both mounted inside boxes located in an unheated concrete instrument room. The instrument lines from the transmitters to the CST are routed through a single penetration in the concrete dike to the storage tank. Once through the dike the instrument lines are exposed to the elements outdoors. The instrument lines are wrapped with electrical heat trace from their connection to the transmitter to their connection to the shutoff valves at the CST. The heat trace is fed from a nonsafety-related power source. PIF 96-0425 documented a case where a nonsafety-related transmitter with the same location and heat trace design as the safety-related transmitters froze. The freezing occurred at the transmitter box. The heat trace was deemed adequate. Leaks in the box insulation and lagging were the cause of the problem. All of the heat traced lines have thermocouples for monitoring the operation of the heat trace. These thermocouples did not report any abnormal temperatures and checked out as normal during subsequent walkdowns.

The team inquired about the use of nonsafety-related power feeds for heat tracing the CST level instruments. The licensee responded that all heat trace throughout the plant is fed from nonsafety-related power sources. In all cases, their performance is monitored by nonsafety-related temperature monitors. The installations are checked on operator rounds for abnormal temperature conditions and operability of the heat trace and temperature monitors. However, PIF 96-0425 noted that, during the incident in which the lines froze as a result of a short in the heat trace cable, the failure remained undetected because of a failure of the temperature monitoring element.

Protection of the line from freezing is lost during loss of AC power events, because the heat trace is powered from nonsafety-related electrical power sources. In this case, off-normal instructions (ONIs) required the operators to monitor the instrument line temperature. ONI-R10 provided a table of time limits versus on the outside air temperature. From 0°F to 16°F an hour and a half time limit was provided to transfer the CST inventory to the suppression pool in anticipation of the instrument lines freezing. For an outside air temperature less than 0°F the ONI required that the inventory be transferred immediately.

E1.2.4.3 Conclusions

The HPCS review identified a design deficiency which has existed since the original design phase of the plant. A section of HPCS suction piping where the piping exits the CST and the CST level instrumentation piping inside of the concrete dike have not been protected against gravitational and tornado-generated missiles, as described in the USAR (50-440/97-201-08).

E1.2.5 System Interfaces

E1.2.5.1 Scope of Review

In this portion of the design review, the team considered the safety/nonsafety system interface between the HPCS and SPCU systems, the HPCS room coolers, and the Unit 2 batteries, as well as the HPCS room flood provisions.

E1.2.5.2 Findings

a. Suppression Pool Cleanup

The PNPP design of the SPCU system interfaces directly with the HPCS. SPCU takes suction from the HPCS suppression pool suction line between the containment isolation valve and the pump. This arrangement requires that the HPCS system be aligned to the suppression pool instead of the CST during SPCU system operation. This system arrangement was the subject of Engineering Design Deficiency Report (EDDR) 10, dated February 13, 1984, which was reported to the commission via letters dated April 30 and June 8, 1984. EDDR 10 stated that the root cause of the deficiency was that the SPCU piping was improperly connected downstream of the HPCS suppression pool suction valve rather than upstream. This indicates the intended design was to have the SPCU system suction interface between the containment penetration and the containment isolation valve. EDDR 10 states the SPCU suction valves F010 and F020 (G42) system are normally closed, and if open, automatically close on a LOCA signal corresponding to reactor water level 1 at which time the SPCU system would receive an isolation signal. Under the intended design, HPCS would be aligned to the CST and SPCU could be operated from the pool with the HPCS suppression pool isolation valve closed. Under the as built configuration SPCU operation required HPCS alignment to the pool. With HPCS initiation at reactor vessel level 2 and SPCU isolation at reactor vessel level 1, EDDR 10 indicated that HPCS would be inoperative until the reactor water level reaches level 1. The action taken to correct this situation was to change the isolation signal to close SPCU suction valves whenever HPCS is initiated.

This solution corrected the isolation signal problem only. The mechanical configuration which requires HPCS alignment to the suppression pool for SPCU operation was left unchanged. As indicated in the FDDR, the SPCU suction valves F010 and F020 (G42) system were intended to be normally closed. The SPCU system was not intended to be normally in operation. This is consistent with USAR Section 6.2.4.2.2.2, "Justification with Respect to General Design Criterion (GDC) 56," which states that the suppression pool cleanup return line is used for suppression pool return flow during periods of suppression pool cleaning and mixing. The USAR states that containment isolation requirements for the return line is satisfied, in part, on the basis that the line is normally closed. In response to team questions, the licensee indicated that SPCU is essentially always in operation and HPCS is essentially always aligned to the suppression pool. The team noted this alignment is not consistent with the HPCS classification and function to backup the RCIC system, including initially take suction from the CST as the preferred source of

water. Although the licensee indicated that the suppression pool alignment is the safety-related alignment for normal operation, the team considers this to be inconsistent with the facility operation as described in the USAR. Because the licensee did not develop a safety evaluation as required by 10 CFR Part 50.59 for continuous operation of the SPCU system which was different than that described in the USAR, the team identified this issue as URI 50-440/97-201-09.

The team reviewed the ability of the SPCU system to support HPCS operation by isolating the suction valves upon HPCS initiation. GE Design Specification 22A3131AD, Requirement 4.4.1, specifies that the HPCS system must be capable of starting and delivering rated flow into the vessel within 27 seconds following receipt of an initiation signal. Two butterfly valves, F010 and F020 (G42), powered from Division I and II power supplies isolate the SPCU suction from the HPCS system. The closing time for these valves is 35 seconds without consideration of power supply startup timing. This exceeds the 27 seconds required for HPCS to reach full flow. The team noted the HPCS system would be operating in parallel with the SPCU system until the SPCU suction valves completed their stroke. This consideration was not consistent with the mechanical design calculations for HPCS (in particular, Calculation E22-1, "NPSH Calculation—HPCS System"), nor with the description in USAR Section 6.3.2.2.1 for NPSH calculations in accordance with RG 1.1. PIF 97-0526 was issued by the licensee to document this finding.

The licensee initiated a review of the HPCS NPSH calculations to address the effects of SPCU operation with a normal operating flow rate of 2000 gpm. The team noted that the piping from the isolation valves to the SPCU pump is nonsafety but seismically-supported, while piping downstream of the SPCU pump is nonsafety, nonseismic, and also not seismically supported. The team questioned the basis for the assumption of a 2000-gpm normal flow rate. The licensee referred to a letter (PY-DIDR-072), entitled "Revision of Break Type Criteria for Moderate-Energy, Nonsafety-Related, Non-Seismic, Category I Piping Outside Containment," dated May 6, 1982. This letter provided the basis for relaxation of the original PNPP assumption of full circumferential breaks in moderate-energy, nonsafety-related, non-seismic, Category I piping outside containment to permit consideration of leakage cracks only. On the basis of this criterion, the licensee indicated the 2000 gpm normal flow rate would be bounding. The team concluded that the issue of pipe break (versus pipe crack) criteria required further review of the plant licensing basis. Consequently, the team deferred this issue to the NRC staff for review as URI 50-440/97-201-10.

The licensee recalculated available NPSH considering both the normal flow rate of 2000 gpm and an SPCU pump runout condition of 3500 gpm if a pipe rupture downstream of the SPCU pump was assumed. Preliminary results of this reanalysis indicate neither the 2000 gpm nor the 3500 gpm SPCU flow rate in parallel with HPCS operation would support HPCS NPSH requirements assuming a maximum suppression pool temperature of 212°F as currently stated in the USAR Section 6.3.2.2.1. A reduction in the maximum suppression pool temperature from 212°F to 185°F was required to demonstrate acceptable NPSH results. The licensee stated that 185°F is above the maximum analyzed suppression pool temperature of 183°F and is consistent with the

assumptions being used for the ECCS strainer modification in response to IE Bulletin 96-03. The licensee has issued PIF 97-526 to document and resolve this issue.

Also, as a result of the SPCU system taking suction from the HPCS suction line downstream of the HPCS suction valve, the SPCU valves are not considered containment isolation valves. Review of the Pump and Valve Inservice Testing Program, Revision 3, and the program for Primary Coolant Leakage Reduction for Systems Outside Containment, PAP-1111, Revision 1, verified that the SPCU suction valves are not leak tested. The ISTP requires only stroke time testing. This could jeopardize the operation of the HPCS system because, if while HPCS was operating, the SPCU valves developed a significant leak, the HPCS suction valve would have to be closed, terminating HPCS operation.

The team concluded that the design of the SPCU/HPCS interface, which would require HPCS isolation in the event of a SPCU system leak represents an apparent oversight in the design. This condition has existed since the initial licensing period because of insufficient analysis and corrective actions regarding the SPCU deficiencies identified in EDDR 10. The team stated that this issue would be reviewed by the NRR technical staff. Consequently, the team identified this issue as URI 50-440/97-201-11.

b. Surveillance Testing of HPCS Room Cooler—GL 89-13

The team reviewed the HPCS Room Cooler with regard to heat exchanger performance test requirements defined in GL 89-13. The HPCS room cooler is an air-to-water heat exchanger which rejects heat from the HPCS pump room to the ESW system. The team identified the following concerns during this review:

- PNPP response to GL 89-13, "Service Water Problems Affecting Safety-Related Equipment," PY-CEI/NRR-1121, dated January 26, 1990, stated that "... The ESW air-to-water heat exchanger (HPCS room cooler) will be inspected and cleaned at each refuel outage, fin and tube side, as an alternative to performance testing." This commitment to clean and inspect the heat exchangers is identified in the Perry Regulatory Information Management System as commitment L01181. In a subsequent submittal to the NRC, Implementation of GL 89-13, "Service Water Problems Affecting Safety-Related Equipment," PY-CEI/NRR-1734L, dated April 8, 1994, the licensee stated that there are 10 ESW heat exchangers at PNPP within the scope of GL 89-13, which have been serviced as follows... High-Pressure Core Spray Room Cooler, 2 Inspections, 2 Cleanings. Documentation of the inspections was available, however, there was no documentation to substantiate the room cooler was cleaned as committed in PY-CEI/NRR-1121 and confirmed in PY-CEI/NRR-1734L. The licensee stated that to their knowledge, inspections were done, but no cleaning was done on the HPCS Room Cooler during the time period claimed in the letter to the NRC. PIF 97-0463 was issued to document this finding. The licensee conducted a review to determine the potential impact of the inaccurate information. The licensee stated that the oversight was not material or willful and intended to correct the

erroneous information in response to findings of this inspection. The team concluded that the missed cleaning and the licensee's subsequent report that the commitments had been satisfied constitute deviations from the licensing commitments. Consequently, the team identified this issue as URI 50-440/97-201-12.

- Letter PY-CEI/NRR-1734L, dated April 8, 1994, also states "With available improvements in methodology cited above, the HPCS Room Cooler will now be tested, or alternate monitoring methods will be determined in accordance with Electric Power Research Institute (EPRI) NP-7552," and "PNPP will maintain the present testing frequencies of once per cycle until such time as our testing demonstrates that a reduced frequency is warranted." The HPCS Room Cooler was tested in June 1995. Calculation M39-6, HPCS Room Cooler Performance Test Results 1995, deemed the test results inconclusive. Since June 1995, no other operability test was conducted. The licensee stated that there were no intentions to inspect the room cooler before October 1998 and maybe not until October 1999, even if no conclusive testing can be achieved by that time. The team noted the licensee has not established a performance test program for the HPCS room cooler and has reverted to the inspection program, but has extended the frequency beyond each cycle without a history of testing to demonstrate that a reduced frequency is warranted. The team considers this a deviation from the licensing commitment to inspect and clean the HPCS room cooler during each refueling outage, as stated in the PNPP response to GL 89-13, "Service Water Problems Affecting Safety- Related Equipment," PY-CEI/NRR-1121, dated January 26, 1990. In addition the team considers this a deviation from the licensing commitment to maintain test frequencies of once per cycle until such time as testing demonstrates that a reduced frequency is warranted, as stated in Implementation of GL 89-13, "Service Water Problems Affecting Safety-Related Equipment," PY-CEI/NRR-1734L, dated April 8, 1994. The team, therefore, identified these deviations as URI 50-440/97-201-13.

c. HPCS Room Cooler Filters

During the HPCS system walkdown, the team observed that the room cooler filters were exposed without any protection from direct impact by water spray or debris. The licensee indicated that the only spray the filters could be exposed to is from the HPCS piping. Such a piping failure would render the HPCS system inoperable in which case the filters would not be needed. The only non-HPCS pipe in the room is the SPCU pipe, whose location cannot jeopardize the filters. The team reviewed the room cooler vendor manual which did not mention of any protection requirements for the filters. The team also verified that the existing filters possessed all the required parameters of the original filters.

d. Battery Room Floor Drains

Floor drains in the Unit 2 Division II and as Unit 1 Division III Battery rooms appear to have a screen beneath the cover and were full of debris. The team was concerned whether the drains were functional. PIFs 97-0423 and 0424 address cleaning the drains, and verification that a

battery spill into the drain system would not create an environmental hazard. The licensee's documentation of these housekeeping items as well as many other items in the corrective action process represented good sensitivity as to threshold for problem identification.

e. Unit 2 Batteries Used to Support Unit 1 Operation

Unit 2 Division III batteries support the Unit 1 Division III batteries during maintenance activities. PNPP initiated a PIF 96-2833 dated 8-30-96 to evaluate incomplete construction of Unit 2 Division III battery room for seismic restraints built in accordance with the design drawings. Engineering performed a walkdown to identify any potential seismic interactions in the Unit 2 Division III battery room. The review concluded that there were no credible hazards (i.e., items of considerable weight with missing or inadequate anchorage) located within a falldown distance of the batteries. The nonsafety commodities (e.g., conduit, light fixtures, etc.) adjacent to the batteries are well supported and do not pose a seismic impact or falldown concern. The vertical cable drop to the batteries is acceptable. The acceptability is contingent upon the cable and/or conduit being well supported and of adequate length (i.e., with adequate slack) to accommodate any differential seismic movement between the battery rack and the conduit.

E1.2.5.3 Conclusions

The team identified a variety of items regarding the HPCS system mechanical interfaces including the SPCU system, and HPCS Room Cooler testing.

The operation of the SPCU, particularity on a continuous basis, was not consistent with the description of the facility as described in the USAR and was not supported by a 10 CFR Part 50.59 safety analysis (50-440/97-201-09). Operation in this mode did not support the RG 1.1 NPSH evaluations as presented in the USAR (50-440/97-201-11). Deviations from licensing commitments regarding cleaning and frequency of inspections made with respect to GL 89-13 were identified (50-440/97-201-12 and 13).

An additional issue regarding application of pipe break criteria (rather than pipe crack criteria) to nonsafety, non-seismic, moderate-energy piping systems has been referred to the NRR technical staff for review (50-440/97-201-10).

E1.2.6 System Walkdown

E1.2.6.1 Scope of Review

The system walkdown included examinations of the HPCS piping and components not inside the primary containment, as well as the interface with the CST and the SPCU system and the Division III diesel generator. The walkdown also included interviews with plant operators in the control room.

E1.2.6.2 Findings

a. Battery Hold-Down Straps

The top and bottom rows of batteries on Unit 1 and 2 Division III racks did not have the same number of clamp-down supports. Vendor Drawing M-6709-3, "Rack, 2-Step Seismic For 20-3DCU-9 Battery," shows 6 supports on each side of the battery cells. PIF 97-0407 documents this discrepancy. The licensee performed an operability determination and verified that the observed condition did not affect battery operability. The licensee's corrective action for PIF 97-0407 should determine the root cause as to why the brackets were not installed. In addition, the corrective action should result in a revision to the drawing, supported by a detailed calculation. The team, therefore, identified this issue as Inspection Followup Item (IFI) 50-440/97-201-14.

b. Battery Conductors

Bending Radius - Unit 1 Division III battery cables 1E22D206C and 1E22D208C, Unit 2 Division III battery cables 2E22D208C and 2E22D212C were bent in a 3" diameter or greater, 360-degree coil at the termination point. Engineering Instruction (GEI) 0007, "Cable Termination Instruction," Attachment 2, Sheet 2 of 2, Termination Data Sheet (Power Cables)," provides a Step 7.4, "Training Radius Maintained," Drawing D-215-801, "Cable Pulling Criteria, Bending and Training Radius," Revision J, specifies that the training radius for these cables (EKA-171, 1/C #2) is 1.5." Nonconformance Report PPDS-3846, Revision 1, dated May 15, 1989, had previously dispositioned this condition as acceptable.

c. Battery Maintenance-Vendor

The team noted during their system walkdowns that a vendor was performing repairs on Division I and II batteries and requested from the licensee details and scope of the work in progress. According to licensee, during the performance of weekly battery surveillance test (SVI-R42-T5202) and SVI-R42-T5203) on May 20, 1996, an electrolyte leak was discovered in the battery jars of various cells at the seam on the top cover. PIF 96-2149 was issued to identify and correct the leakage problem from the cell covers. The leak resulted from a defective seal between the cell jar and the top cover, as well as poor workmanship during battery fabrication. The electrolyte leak is not a battery failure and does not impact the system function and operability. The manufacturer (Yuasa-Exide) was on site performing the repairs to correct the leakage problem.

d. Cable Separation

Conduits 1R33D98A and 1R33D102A in the Division I battery charger room were in contact with each other and were wrapped in 3M insulation. Raceway separation barrier installation drawing SS-201-146, Sheet 143, Revision EE, criteria allows the conduits to be wrapped with 0" separation and therefore the installation was acceptable.

e. Cable Tray/Raceway/Conduit Fill Walkdown

Tray and conduit % fill values for Cable Trays "C" 1951 and 1952 and conduit 1R33C2977C in the Unit 1 Division III battery room were checked and found acceptable. Summary of Tray Data Report CKSR2000, documents tray 1951 as being 31.9% and 1952 being at 38.6% filled. Conduit Summary Report CKSR2200 identifies raceway 1R33C2977C as being 35.9% filled. The fill criteria specified in USAR Section 8.3.1.4.3 are 50% for tray and 40 percent for conduit.

f. Conduit Supports

Unit 1 Division III battery room conduit flex 1E22A212C dropped from the ceiling with no support. Conduit Layout Drawing D-215-004, Sheet 601, Note 6C.2 and Table 3, allow the maximum conduit length between supports to be up to 10 feet. The conduit in question was field verified to be 8 feet, 6 inches long, and was found to be acceptable.

E1.2.6.3 Conclusions

With the exception of the battery hold-down straps (50-44/97-201-14), the team considered the electrical equipment and cable installation including separation and fill to be acceptable in accordance with licensee design drawings.

E1.2.7 USAR Review

The team reviewed the appropriate USAR sections for the HPCS and associated electrical and control systems. The team identified the following discrepancies with regard to statements made in the USAR:

- The team's assessment of the basis and design features for flooding due to passive failures within the HPCS room identified inconsistencies between the actual design and the design described in SER (NUREG 0887) regarding control of unisolable post-LOCA leakage within the ECCS rooms. The ECCS room flood capabilities described in the SER were different from that contained in USAR Section 6.3.1.3. The licensee indicated that the USAR description and the design basis was consistent with regulatory requirements in this area. The licensee issued PIF 97-0488 to clarify their design and licensing basis for detection and protection from passive failures of either the HPCS pump seal or valve packing during both normal operation and post-LOCA. The licensee's position on this issue was discussed with NRR technical staff who agreed that clarification of the USAR was needed.

- The team identified the following administrative discrepancies between Calculation PSTG-0014, "Diesel Loading Division I, II, and III," Revision 3, and USAR Table 8.3-1: The licensee had previously identified similar discrepancies with USAR Table 8.3-1 and Calculation PSTG-0014 as documented in PIF 96-2780.

a) USAR Table 8.3-1 identifies loads 1M43C001C and 2C as 0M43C001C and 2C.

b) USAR Table 8.3-1, Note 17, second sentence contradicts Note 20.

c) USAR Table 8.3-1 lists fuel oil transfer pumps 1R45C001C and 2C as 0-second loads. 1R45C001C and 2C are 40-minute automatic cyclic loads for both LOOP and LOCA.

d) USAR Table 8.3-1 identifies a 9-kW load for 1E22C004B and does not agree with the 8-kW load in Calculation PSTG-0014.

e) USAR Sections 8.3.1.1.3.2B6 and 8.3.1.1.3.3B6 refer to "Section 8.3.1.1.2.8," but the correct section is 8.3.1.1.2.6.

- The team identified discrepancies described below indicated that design and calculation changes may not be accurately reflected in the USAR:

a) USAR Table 8.3-1 lists inrush current for HPCS water leg pump 1E22-C003 as 51 amperes, Calculation PRMV-0017, "EHF-1-E Transformer Breaker EH-1305," Revision 0, does not reflect inrush currents for the 1E22-C003 load.

b) USAR Table 8.3-1 lists the inrush currents for HPCS fuel oil transfer pumps 1R45-C001C and 2C as 109A, whereas Calculation PRMV-0017 lists the inrush current as 130A.

c) USAR Table 8.3-1 lists the inrush currents for HPCS diesel generator room fans 0M43-C001C and 2C as 362A, whereas Calculation PRMV-0017 lists the inrush current as 376A.

d) USAR Table 8.3-1 lists the FLA of HPCS diesel generator starting air compressor 1E22-C004B as 13A, whereas Calculation PRMV-0017 lists the FLA as 11A.

e) USAR Table 8.3-1 lists the HPCS ESW pump 1P45-C002 is as 75 hp, 88.5 FLA, and 557A inrush, whereas Calculation PMRV-0017 lists the same load as 75 hp, 85.4 FLA, and 543A inrush.

f) USAR Table 8.3-1 lists the rating of HPCS diesel generator space heater 1E22-D011 as 2 kW, with a load current of 3 amp. Calculation PRMV-0017 lists the same space heater as 1.6 kW, with the load current of 2.01 amp. Drawing D-206-029/BB, "Electrical One Line Diagram, Class IE, 480-V Bus EF1D," lists the same space heater as 2.4 kW.

g) USAR Table 8.3.11, "Penetration Protection," was generated from Calculation ECPC-0001, "Electrical Penetration I^2T Verification," Revision 2, dated 8-25-92. Input to ECPC-0001 was from Calculation PSTG-0006, "PNPP Short Circuit Study," Revision 1, dated 6-21-85. Calculation PSTG-0006 is currently at Revision 2, dated 5-20-92. Calculation ECPC-001 and USAR Table 8.3-11 have not been revised to reflect the impact of PSTG-006, Revision 2. The initial review by engineering has determined that the present ampacity values in Calculation ECPC-001 are conservative with respect to PSTG-006, Revision 2, and the I^2T values and clearing times in USAR Table 8.3-11 will not change significantly.

h) USAR Table 8.3-7 does not reflect the current load profiles of Calculation PRDC-0005, "Load Evaluation and Battery Sizing of Division I and II Battery Load Profiles," Revision 3, dated May 23, 1996. PIF 97-0425 documents this discrepancy. Currently, all Division I and II surveillance performance and service tests are performed per USAR Table 8.3-7. Operability of the plant systems, functions, and equipment are not affected by the inconsistency between USAR Table 8.3-7 and the Calculation PRDC-0005, Revision 3. The load profiles listed on USAR Table 8.3-7 are greater (conservative) than the profiles addressed in Calculation PRDC-0005, Revision 3. Corrective Action 97-0425-001 will revise the USAR Table 8.3-7 for completeness.

- The licensee evaluated the above discrepancies by verifying that either the items were currently being reviewed under an existing PIF or a new PIF was issued. The licensee issued new PIFs 97-0343, 97-0350, 97-0395, and 97-0500 to document those items not captured in the corrective action system.

The licensee had not yet corrected the above discrepancies or updated the USAR to ensure that the USAR contained the latest information, as required by 10 CFR 50.71(e). Consequently, the team identified this issue as URI 50-440/97-201-15.

E1.3 Emergency Closed Cooling (ECC) System

E1.3.1 System Description and Safety Function

The safety function of the ECC system is to provide a reliable source of cooling water to safety-related components during and after transient and/or accident conditions. These components include the control complex chillers: residual heat removal (RHR) pump seal coolers; low-pressure core spray (LPCS), and RCIC pump room unit coolers; and hydrogen analyzers.

Other functions of the ECC system are to supply cooling water to served components during hot standby, normal shutdown, and plant testing modes of operation and, if required, provide cooling water to the fuel pool heat exchangers following a DBA, if required.

The ECC system is a closed, intermediate cooling water system consisting of two redundant, independent loops designated as loops A and B. The primary components of each loop include a pump, heat exchanger, surge tank, MOVs, and interconnecting piping. A chemical addition tank is shared by both loops. The ECC heat exchangers are cooled by the ESW system. The components served by each ECC loop are as follows:

Loop A	Loop B
LPCS Pump Room Cooler	RHR Pump B Room Cooler
RCIC Pump Room Cooler	RHR Pump B Seal Cooler
RHR Pump A Room Cooler	RHR Pump C Room Cooler
RHR Pump A Seal Cooler	RHR Pump C Seal Cooler
Hydrogen Analyzer A Cooler	Hydrogen Analyzer B Cooler
Control Complex Chiller A	Control Complex Chiller B

Each ECC pump takes suction on its loop suction header and discharges through the shell of an ECC heat exchanger to the system loads. After serving the system heat loads, the warmed ECC water returns to the pump suction. The surge tank ensures that an adequate pump suction head is available and facilitates system fill and makeup. The ECC system is not normally in operation and is designed as a standby system. A LOCA or loss of offsite power (LOOP) signal automatically starts both ECC pumps, repositions valves to supply ECC water to the control complex chillers, and isolates the normal, nonsafety-related cooling water supply to the control complex chillers.

The ECC system is designed to perform its required cooling function following a DBA, assuming any single active or passive failure and LOOP and is protected to withstand the effects of natural phenomena including earthquakes and tornadoes. The system is classified as Safety Class 3 and Seismic Category I, except for its portions that are associated with the chemical addition tank and piping downstream of vents and drains.

E1.3.2 Mechanical

E1.3.2.1 Scope of Review

The mechanical design review of the ECC system included design and licensing documentation reviews, system walkdowns, and discussions with the cognizant system and plant design engineers. The team reviewed applicable portions of the USAR and TS; the SDM section; process flow diagrams and other drawings; 12 calculations; 8 DCPs; system operating, inservice and surveillance test procedures; CRs; PIFs; and operating experience reviews (OERs). The scope of the review included verification of the appropriateness and correctness of design

assumptions, boundary conditions, and system models; confirmation that design bases are according to licensing bases; and verification of the adequacy of testing requirements.

Specific topical areas covered during the mechanical design review include system thermal/hydraulic performance requirements (e.g., heat removal capacity, pump and system curves, and pump NPSH); system design pressure and temperature; overpressure protection; surge tank design parameters; component safety and seismic classifications; component and piping design codes and standards; and single failure vulnerability.

E1.3.2.2 Findings

The team verified that each loop of the ECC system was capable of removing the design heat loads from served safety-related components during and following a DBA. The system appeared to have adequate flow and heat transfer margins to accommodate future equipment degradation, as evidenced by the difference between the required and designed flow rates (1820 gpm versus 2300 gpm) and the current position of valves that are throttling ECC flow to served components. The safety classifications and specified codes and standards were appropriate. The design pressures and temperatures specified for piping and components, and the provided overpressure protection features were adequate. Complete independence of the two ECC loops was verified where no single active or passive component failure would prevent the system from performing its safety function. However, the team identified USAR clarity and inconsistencies in the manner in which passive failure was defined. Specifically, USAR Section 1.2.1.2 item 1 indicates that passive failures only apply to electrical failures. Whereas, USAR Section 6.3.2.6 refers to passive failures as valve stem and pump packing failures. Clarity is needed to define what is the Passive Failure Design. The licensee is addressing these inconsistencies in PIF 97-0566, and the matter is designated as IFI 50-440/97-201-16.

The system design documents reviewed by the team adequately support the design and licensing bases, except for the discrepancies and open items discussed in the following paragraphs.

a. Surge Tank Emergency Makeup Design Basis

USAR Section 9.2.2 currently states that the ECC surge tanks are designed to maintain a 7-day supply of water, with normal system leakage, without the need to provide makeup water. Expected normal system leakage is stated as 0.5 gallons per hour (gph) from pump seals and valve stem packing. However, an event that occurred in 1993, as reported in Licensee Event Report (LER) 93-021, identified a previously unrecognized post-accident leakage path from the ECC system. This path would be through closed valves P42-F295A,B and P42-F325A,B that isolate the ECC system from the nonsafety-related nuclear closed cooling (NCC) system following a DBA. The NCC system is the normal cooling water source for the Control Complex chillers, whereas the ECC system cools the chillers after an accident. The licensee has established allowable leakage limits for the subject valves at 3.0 gpm for ECC Loop A and 3.5 gpm for Loop B, derived in Calculation P42-24, "Maximum Allowable Leakage from P42 System," Revision 1.

These limits are on the basis of operator action taking place within 30 minutes after the DBA to manually initiate emergency makeup to the surge tanks from the ESW system. Without this makeup, the surge tanks would empty, NPSH for the ECC pumps would be lost, and the ECC system would be disabled.

In compliance with 10 CFR 50.59, the licensee prepared Safety Evaluation 96-128, dated October 10, 1996 to evaluate the USAR and procedural revisions associated with the change in the surge tank sizing basis from a 7-day supply without necessary makeup to a 30-minute supply. The safety evaluation was also used as a basis for the use-as-is disposition of PIF 96-2846, associated drawing change notice (DCN) 5541, and USAR change request (CR) 96-150. The safety evaluation concluded that the change did not constitute an unreviewed safety question, primarily because of the licensee's belief that the modified design continued to satisfy the review procedures stated in SRP Section 9.2.2, Part III, which states:

> "The system is designed to provide water makeup as necessary. Cooling water systems that are closed loop systems are reviewed to ensure that the surge tanks have sufficient capacity to accommodate expected leakage from the system for seven days or that a seismic source of makeup can be made available within a time frame consistent with the surge tank capacity (time zero starts at low-level alarm)."

Overall, Safety Evaluation 96-128 was comprehensive and well written. However, the team's review of the safety evaluation identified a number of concerns that, collectively, caused the team to challenge the conclusion of the safety evaluation, as described below:

- Multiple operator actions would be required to read the local surge tank level gauges (at 30 minute intervals), locally open valves P45-F508A,B to establish makeup flow from the ESW system, and subsequently close those same valves if the surge tanks have completely filled with water and are overflowing. Within the first 90 minutes after a DBA, the licensee calculated that total operator radiological exposure would be about 12 rem. The cumulative operator exposure over the entire duration of the accident was not calculated. NUREG-0737, Item II.B.2, "Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May be Used in Post-Accident Operations," establishes the guidelines of GDC 19, "Control Room", as the dose rate criterion to be applied for vital areas that are infrequently accessed under post-accident conditions. This criterion is 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident. Therefore, a minimum of three separate operators would be needed to carry out the required actions for the first 90-minute period without exceeding the GDC 19 dose criterion.

- The safety evaluation did not adequately assess the potential for operator error (omission or commission). It discounted the possibility of operator error, primarily because of the simplicity of the required actions and operator familiarity with the required activities.

However, working conditions immediately following a DBA would be stressful, and there is no emergency lighting in the areas where actions would be required, necessitating the use of portable light sources. Thus, the team considered a single-operator error to be credible. The licensee stated that a single- operator error would result in the failure to provide makeup to only one surge tank. The licensee does not consider credible the postulated failure of the operator to provide makeup to both surge tanks, even though a single procedural step covers filling both ECC surge tanks.

- The safety evaluation did not address the potential for surge tank overpressurization when makeup from the ESW system fills the tank water-solid. The probability of this occurring is increased, since the operator would open the makeup valves and then leave the surge tanks untended and unmonitored for at least 30 minutes. Preliminary licensee calculations indicate that the maximum makeup water flow rate from the ESW system is approximately 117 gpm, resulting in a surge tank pressure of about 4 psig. This exceeds the surge tank atmospheric design pressure, but will not exceed the maximum pressure retaining capability of the tank, as calculated by the licensee. Therefore, the surge tank will not fail as a result of filling it water-solid with makeup from the ESW system.

- The safety evaluation cited American National Standards Institute/American Nuclear Society (ANSI/ANS) 58.8-1984, "Time Response Design Criteria for Nuclear Safety-Related Operator Actions," as the basis for choosing the 30-minute operator action time, although the safety evaluation notes that Perry is not committed to meet this standard. However, not all of the provisions of the standard have been met regarding safety-related operator actions taken outside the control room:

    - No emergency lighting is provided in the two separate areas where the operator must read the local surge tank level gauges or manually operate the ESW makeup valves. The use of portable light sources is required.

    - No safety-related surge tank level indication is provided in the control room to inform the operator that action is needed or to provide information and feedback regarding the success of performed actions. The high/low surge tank annunciators that are provided in the control room are not safety related and cannot be relied upon to provide valid post-accident information. The surge tank level will only be known at 30-minute intervals when an operator is dispatched to read the local-level gauges.

The team also reviewed the plant's original SER (NUREG-0887), dated May 1982, and noted that NRC acceptance of the ECC system design appeared to be dependent (in part) on the ability to initiate ESW makeup to the surge tanks by manual action from the control room. This SER

cceptance was consistent with information presented in the Perry Final Safety Analysis Report (FSAR) at that time, which stated:

> "This is a remote manual function requiring operator action in the control room."

In FSAR Amendment 17, dated March 6, 1985, still before receipt of the operating license, the FSAR was revised to indicate that initiating surge tank makeup from the ESW system was locally performed. Subsequent SER supplements did not specifically address this change.

On the basis of the reviews described, the team concluded that the change to the ECC surge tank sizing basis from a 7-day supply to a 30-minute supply, with operator actions required outside of the control room to initiate makeup from the ESW system, may constitute an unreviewed safety question, as defined in 10 CFR 50.59, because it--

- Increases the probability of an occurrence of a malfunction of equipment important to safety. Reliance on operator action at 30 minutes after the accident, under stressful and hazardous working conditions, increases the probability that the operator will not correctly perform the required actions.

- Increases the consequences of an accident. Total cumulative operator exposure has increased by 12 rem, and the potential exists that an individual operator's exposure may exceed the GDC 19 limits specified by NUREG-0737, Item II.B.2.

This issue was reviewed by NRR technical staff who also determined that a potential unreviewed safety question existed. This item is designated as URI 50-440/97-201-17.

The team identified several additional deficiencies that were also related to the licensee's Safety Evaluation 96-128. The flooding analysis performed for surge tank overflow used a non-conservative flooding rate of 60 gpm, on the basis of the minimum calculated ESW makeup flow to one ECC surge tank. The team noted that since the operating procedures would direct the operator to initiate ESW makeup to both tanks, the flooding rate should consider the flooding of both tanks (i.e., 120 gpm). The licensee issued PIF 97-0406 to address this discrepancy. However, the team also pointed out that if the ESW makeup flow rate was calculated using assumptions that maximized rather than minimized the flow, the flooding rate would be higher. Preliminary calculations by the licensee determined a maximum ESW makeup flow rate to each surge tank to be 117 gpm, or a total flooding rate of 234 gpm. 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires that licensees correctly translate the design bases into specifications, drawings, procedures, and instructions. The team concluded that the licensee's use of the non-conservative flooding rate in Safety Evaluation 96-128 failed to meet this requirement. Consequently, the team identified this failure as URI 50-440/97-201-18.

USAR Section 9.2.2.2 (page 9.2-24) states that, "In the event that demineralized water makeup does not automatically fill the surge tank, a low-level indication with an alarm is annunciated in the control room to indicate that operator attention is required." Similarly, USAR Section 9.2.2.5 (page 9.2-32) states that "The surge tanks have high- and low-level indication." The actual design includes only a level alarm in the control room with level indication local at the tank. The team considered these statements to be unclear and possibly misleading, since they could imply that surge tank level indication is provided in the control room. These same statements were made in the original FSAR. The licensee issued PIF 97-0469 to clarify that surge tank level indication is only locally provided at the tanks.

b. Non-Conservative ECC Leak Rate Test Procedure

The team reviewed test procedure PTI-P42-P0008, Revision 1, "P42 Leak Rate Test Procedure." The purpose of this procedure is to determine an approximate leakage rate through the valves that isolate the boundary between the ECC system and the nonsafety-related NCC system valves P42-F295A,B and P42-F325A,B. The team determined that the procedure was not conservative because the prescribed test conditions were not representative of post-accident ECC system operation. The test differential pressure (approximately 60 psi) was one half of the value that the subject valves would experience after an accident. Additionally, the test pressure was being applied in the reverse direction from normal accident conditions. The test procedure and acceptance criteria did not adjust the leakage measured under test conditions to expected leakage under post-accident differential pressures. The licensee issued PIF 97-0578 to address these concerns and their initial review determined that current valve leakage, when adjusted to account for the higher post-accident differential pressure, would still be acceptable (3.0 gpm for ECC Loop A and 3.5 gpm for Loop B). The responsible system engineer also noted that a new surveillance procedure (SVI-P42-T2004) was currently being prepared that would correct the deficiencies noted above. 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," and Criterion V, "Procedures" as implemented by the licensee's Operational QA Program, USAR Section 17.2, requires that testing be performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. The team concluded that the existing ECC system leak rate test procedure failed to meet this requirement, and designated this failure as URI 50-440/97-201-19.

c. ECC Pump Minimum Flow Requirement

During the review of design documentation, the team noted a discrepancy in values cited for the minimum required ECC pump flow rate. ECC system operating procedure SOI-P42, Revision 7, Section 2.0, stated a minimum flow value of 560 gpm; however, the Ingersoll-Rand certified pump curve (PDB-B0002, Revision 1) indicated that the minimum required continuous flow was 800 gpm. The team was concerned that the pump was being allowed to operate at a minimum continuous flow rate that is less than that required by the pump vendor. The licensee issued PIF 97-0470 to address this concern. The licensee's investigation determined that the pump vendor's technical manual specified a minimum flow equal to 25% of the best efficiency point or 575 gpm.

The change from 800 to 575 gpm was previously evaluated in 1990 in CR-90-106, and PIF 97-0470 identified appropriate changes to the design documentation and operating procedures. Resolution of this issue should occur through PIF 97-0470 corrective action resolution. Consequently, the team identified this issue as IFI 50-440/97-201-20.

d. Heat Exchanger Tube Thickness and Heat Transfer Coefficient

Calculation P42-33, "Evaluation of Heat Transfer Coefficient and Minimum Required Wall Thickness for ECC Heat Exchangers 1P42-B0001 A/B," Revision 0, dated May 1, 1996, evaluated the minimum wall thickness required for the tubes of the heat exchanger. In particular, the licensee based the calculation on acceptance criteria consistent with the ASME B&PV code, and established the minimum overall heat transfer coefficient on the basis of the fouling factor and the number of tubes being plugged. The team reviewed the calculation for the minimum wall thickness determination and sampled the input data used in the heat transfer computer model and identified the following concern:

> Calculation Section 5, "Method of Analysis," considers the heat exchanger as a pressure vessel and concludes that the rules of ASME B&PV Code, Section VIII, are applicable. This code selection conflicts with the manufacturer's heat exchanger specification sheet that indicates the ASME code requirements as ASME Section III, Class 3. The ASME Form N-1, N Certificate Holders Data Report for Nuclear Vessels identifies the applicable ASME Code as Section III, 1974 Edition, Winter 1975 Addendum, Class 3. The calculation provided no technical basis to justify the use of ASME Section VIII criteria for an ASME Section III component. PIF 97-0531 documents this condition and a comparison between the criteria of Sections III and VIII. This review indicated Sections III and VIII use the identical code methodology and the calculation results are unchanged. The team concluded that the review and approval of this calculation with reference to inappropriate construction codes without technical justification represents a weakness with respect to 10 CFR Part 50, Appendix B, Criterion III, "Design Control." Consequently, the team identified this item as URI 50-440/97-201-21.

e. Evaluation of ECC Heat Exchanger Test Performance

Calculation P42-31, "ECC A Heat Exchanger Test Results—1995," Revision 0, dated September 15, 1995, evaluates the test data recorded during performance of PTI-P42-P001 on August 10, 1995, to assess measurement uncertainty associated with data acquisition and analytical methods. The team's review of this calculation identified the following concern:

> Section 3, "Assumptions," identifies two open assumptions, one assumption requires the test data/results be confirmed via test document acceptance signatures and the second assumption assumes test instrumentation to be within calibration

limits. Post-test calibration was specified to confirm this second assumption. The team noted that this calculation was used as the basis for equipment operability evaluations and outstanding assumptions, open for 18 months, could affect the conclusions. The team requested information on how these calculations were controlled to ensure that open assumptions are verified and closed. At the request of the team, the licensee pursued the status of Calculation P42-31 open assumptions and found that the post-test calibration indicated that the instrumentation for 1 of 8 temperature measurements on both the ECC inlet and outlet were out of calibration. The licensee indicated that Engineering should have been notified via memo that the test instrument was out of calibration at the completion of the post-test calibration. However, no documentation of such notification was evident. Calculation P42-31 was re-evaluated on the basis of the remaining valid instrumentation readings, with only a minor difference in the results attributable to the small error in the measurements and the statistical methods used. PIF 97-0543 documents the concern with calculation with open assumptions and includes a partial listing identifying 44 calculations with unconfirmed assumptions. Identified calculation titles indicate that at least 13 of these calculations involve equipment performance testing, including Division I and II jacket water heat exchanger testing in 1994. Other calculations appear to involve equipment qualification, sizing, and modifications. The team concluded that the issues of long-term unconfirmed calculation assumptions and failure of the post-test calibration to alert Engineering to instrumentation that is out of calibration represent weaknesses with respect to 10 CFR Part 50, Appendix B, Criterion III, "Design Control." Consequently, the team identified this issue as URI 50-440/97-201-22.

E1.3.2.3 Conclusions

The team concluded that the mechanical design of the ECC system was generally acceptable, and the system was capable of performing its safety function with operator intervention. However, the team also concluded that the safety evaluation associated with a change in the design bases for the ECC system surge tank, from a 7-day supply to a 30-minute supply which relied on extensive use of early manual operator intervention, was inadequate. The resultant change to the USAR effectively changed the plant from that described in the USAR. Because the change resulted in an increase in the potential for failures not previously analyzed and an increased in accident consequences the NRC determined that a potential USQ exist and NRC approval was required (50-440/97-201-17).

The flooding rate determined by safety evaluation 96-128 and supporting calculation to be acceptable used non-conservative values (50-440/97-201-18). Mechanical modifications that were reviewed by the team were appropriate for resolving the identified problems, and the modifications did not change the design bases of the system. However, the temperature control valve modification was not totally effective, as discussed in Section E1.3.5 of this report. Other

deficiencies identified during the team's review of design documentation included a non-conservative test procedure for determining ECC system leakage (50-440/97-201-19); inconsistent design information regarding the ECC pump minimum flow requirement (50-440/97-201-20); inappropriate code references for heat exchanger evaluations (50-440/97-201-21); and issues of unconfirmed calculation assumptions and test control (50-440/97-201-22).

The licensee initiated actions to address these items through their condition reporting and corrective action program.

E1.3.3 Electrical

E1.3.3.1 Scope of Review

The team reviewed the electrical design for normal and emergency operation of the ECC system, selected MOVs, circuit breakers, fuses, and interlocks. The team also compared the design drawings to the SDM, applicable sections of the USAR, and TS to verify consistency in the documents. In addition, the team reviewed the calculations related to voltage drop, electrical loading, and coordination for selected ECC components and associated electrical components to determine the adequacy of the available voltages, equipment loading, protective system coordination, and electrical isolation and independence.

E1.3.3.2 Findings

The team verified that the ECC system was powered from a separate emergency power bus and that the electrical loading of the individual components had been considered in the emergency diesel generator Division I and II capacity calculations. The sequence and timing of loading of ECC pumps and valves onto the respective EDG was consistent with the USAR.

The team determined that the electrical design requirements were appropriate and consistent in the reviewed documents. No unacceptable conditions were identified during this review.

E1.3.3.3 Conclusions

The team concluded that the electrical design of components that perform engineered safeguard functions of the ECC system was adequate and operating within the design limits.

E1.3.4 Instrumentation and Controls (I&C)

E1.3.4.1 Scope of Review

The team evaluation of the ECC I&C consisted of design documentation reviews, interviews, and a walkdown of the ECC system. The review concentrated on protective functions to provide nuclear safety-related components with a reliable source of cooling during and after a

LOOP/LOCA or LOCA. The design was assessed for the ability to meet USAR commitments and to operate within TS limits. Attributes reviewed comprised of instrument installations, instrument setpoints, instrument power and AC and DC control power provisions, and remote and alternative shutdown provisions. Documents reviewed included applicable sections of USAR Chapters 1, 3, 5, 6, 7, 8 and 9; TS, the SDM, vendor documents; P&IDs; logic diagrams; electrical wiring diagrams; instrument installation drawings; calculations; calculation change records; PIFs; ARs; CRs; NRs; and DCPs.

E1.3.4.2 Findings

a. Remote Shutdown Design

The team reviewed the provisions made in the design of the ECC system to operate the system from outside the control room if the control room had to be vacated. Division A was designated as the remote shutdown division. Division B was designated as the alternate remote shutdown division. The ECC system is required for safe shutdown of the reactor. The controls of the Division A ECC pump can be transferred to the remote shutdown control panel. The transfer scheme included transferring an alternate source of control power to the ECC pump breaker. The controls for the Division B ECC pump did not have provisions to transfer control to the alternative remote shutdown control panel. The pump must be started manually using the control switch at the ECC pump breaker. No provisions were made to provide an alternate source of control power for the Division B pump controls. The PPNP Appendix R requirements allow 72 hours for repairs to be conducted utilizing only onsite resources for alternate remote shutdown. The design corresponded to that described in the PNPP Appendix R safe-shutdown analysis.

None of the ECC system valves for lining up the system flows and isolating the ECC system from the nuclear closed cooling (NCC) system, other non-divisional systems or separating the two divisions had provisions for transferring their control out of the control room to the remote and alternate remote shutdown control panels. The repositioning of these valves is procedurally controlled. Operators manually deenergize and realign these valves as required. The Appendix R analysis and the respective procedures were reviewed to verify the inspection observation. The specific tasks to be performed to manually position the valves were reviewed. Extensive operator action was required to realign the valves. The valves appeared to be accessible from the floor level without using ladders. Normal lighting in the area was sufficient for operators to execute their required task.

b. Surge Tank Low-Level Alarm Setpoint

Calculation P42-5, "Emergency Closed Loop Cooling Water System Surge Tank Sizing," was issued to verify that the surge tank had sufficient capacity to accommodate the water expansion within the ECC system and to determine the capacity of the surge tank at the low-level setpoint compared to the original design requirement of 250 gal. The calculation used a setpoint value of 667 feet, 9 inches, taken from the Master Setpoint List. Calculation P42-T04, "Emergency

Closed Cooling Surge Tank Level Hi/Lo Alarm," calculated the uncertainties associated with the level switches that actuates the alarm. P42-T04 referenced Magnetrol Drawing D119-03 for the setpoint values and noted that the setpoint and reset values are fixed and set at the factory. P42-T04 gives different values from P42-5 for the setpoints of 667 feet, 6.75 inches, for tank A and 667 feet, 7.875 inches, for Tank B. The difference between the two numbers was attributed to a difference in the elevation of the tanks. The difference from the setpoint value in P42-5 was not explained.

The licensee issued PIF 97-0540 to address the above setpoint value disagreement.

E1.3.4.3 Conclusions

The Perry Appendix R resolution for remote shutdown ability, made extensive use of manual operator action a feature of their design. Calculation P42-5 incorrectly referenced the setpoint list as the source document for the low-level setpoint value.

E1.3.5 System Interfaces

E1.3.5.1 Scope of Review

The team selected the following systems that interface with the ECC system and verified that the interfacing system design information for supporting the function of the ECC system was appropriately considered; the ESW system which supplies cooling water to the tube side of the ECC heat exchangers, provides emergency makeup to the ECC surge tanks, and cross-ties to the Unit 2 ECC system piping to provide cooling water to the fuel pool heat exchangers following an accident; the NCC system which provides normal cooling water to the Control Complex chillers and the fuel pool heat exchangers; and the Two-Bed Demineralized Water System which provides normal makeup to the ECC surge tanks.

In addition to reviewing the interfacing system design information for the above systems, the team examined installation of the interfaces during the ECC system walkdown.

E1.3.5.2 Findings

System interfaces were generally acceptable and consistent with the ECC system design and licensing bases, except for the items discussed in the following paragraphs.

a. ECC Temperature Control During the Winter

Under accident conditions LOCA and/or LOOP), the ECC system supplies cooling water to control complex chillers A and B. These chillers represent approximately 90% of the ECC system heat load during accident conditions. The cooling water supplied to these chillers must be maintained above 55°F to prevent the chillers from tripping because of a low refrigerant

temperature. The ECC system heat exchangers are cooled by the ESW system that draws water directly from Lake Erie.

As previously reported in LER 94-005, in the winter, when the lake water was cold and the heat loads on the ECC system were low (i.e., the system was operating to support surveillance testing), the ESW system flow to the ECC heat exchangers overcooled the ECC system below 55°F. This could have caused both control complex chillers to trip. It should be noted that this condition would not have occurred during post-accident ECC system operation, when maximum heat loads would be imposed on the system. In response to this event, the licensee installed a temperature control valve (TCV) in each ECC loop (reference DCP 94-0027). This three-way TCV causes ECC flow to bypass the heat exchanger, as necessary, to maintain ECC system temperature above 55°F with minimum heat loads on the ECC system.

Recent experience, as documented in PIF 96-1265, indicates that the TCV modification has not been totally effective. Because of the configuration of the heat exchanger bypass piping, previously unrecognized heat transfer phenomena result in the cooling of the ECC water even when the ECC flow totally bypasses the heat exchanger. To compensate for this marginal design modification, administrative controls had to be reinstated to limit ECC system operation under minimum heat load (i.e., surveillance testing) conditions, thereby placing a burden back onto the operators. In addition, because the ECC system temperature element is located on the ECC heat exchanger discharge pipe and in close proximity to the heat exchanger outlet (as confirmed during the system walkdown), the measured temperature can be significantly influenced by the same heat transfer phenomena noted above and does not always represent the true ECC system temperature. If the ECC system is idle and the ESW system is operating, the ECC temperature element may give a false low-temperature alarm in the control (the alarm setpoint is 60°F). This is a nuisance alarm that diverts the operator's attention and is meaningless when the ECC system is not actually operating.

As previously noted, the ability of the ECC system to perform its safety-related function is not impacted by these temperature control deficiencies since the expected post-accident heat loads would maintain system temperature above 55°F. The licensee has recognized the temperature control shortcomings and has planned several actions to address them. These include the performance of tests to better understand the heat transfer phenomena involved and to determine the feasibility of operating the control complex chillers at lower ECC condenser inlet temperatures that would allow a lowering of the ECC low-temperature alarm setpoint. The team found these actions appropriate and did not have any further questions.

b. Cross-Tie Between Unit 1 ESW and Unit 2 ECC Systems

The Unit 2 ECC system was originally designed to supply safety-related cooling water to the common fuel pool cooling and cleanup (FPCC) system heat exchangers following a DBA. Since Unit 2 is not operational, piping cross-ties were installed between the Unit 1 ESW system and the Unit 2 ECC system such that the Unit 1 ESW system can supply safety-related, post-accident

cooling water to the FPCC heat exchangers. As noted in USAR Section 9.2.2.6, manual actions are required at greater than 10 minutes following a DBA to establish the ESW-to-FPCC system alignment. The team reviewed Section 7.5 of system operating instruction SOI-G41, "Fuel Pool Cooling and Cleanup System," which identifies these manual operator actions. The team noted that the procedure calls for the venting of certain ECC piping and the FPCC heat exchangers to eliminate voids that could result in water hammer when ESW is admitted to the Unit 2 ECC system piping.

The team questioned whether post-accident operator radiological exposure during the performance of the venting activities had been assessed by the licensee in accordance with NUREG-0737, Item II.B.2. The licensee responded that a dose assessment had not been performed; however, PIF 97-0248 has recently been issued to generically address the lack of dose assessment and specified operator travel paths for all accident mitigating actions required by plant procedures. Proper disposition of this PIF should satisfy the guidance given in NUREG-0737. This licensee identified item did not appear to be willful, was not reasonably preventable by previous corrective actions, and should be corrected in a reasonable time frame commensurate with the requirements of the licensee's corrective action program. Followup of the licensee's resolution of these deviations from commitments, stated in USAR Section 12.6 and Appendix 1A, to satisfy NUREG-0737, Item II.B.2. is identified as URI 50-440/97-201-23.

E1.3.5.3 Conclusions

The design of the ECC system interfaces was generally satisfactory and supported performance of the ECC system safety functions. Two concerns that do not affect the capability of the ECC system to perform its safety functions (ECC temperature control and post-accident vital area access assessments) were identified by the team. The licensee has previously been aware of these concerns and is taking actions to address them (50-440/97-201-23).

E1.3.6 System Walkdown

E1.3.6.1 Scope of Review

The team performed a walkdown of selected portions of the ECC system. Piping and mechanical components, piping interfaces with the ESW system, and installation of instrumentation and electrical components were examined to verify consistency with plant drawings. Particular attention was directed to the location and arrangement of the surge tanks, their associated piping (makeup and venting), and level instrumentation to confirm the acceptability of the post-accident operator actions described in Section E1.3.2.2 of this report. The team also visited the control room to examine instruments and displays used to monitor ECC system operating status.

E1.3.6.2 Findings

The material condition of the system and general housekeeping appeared to be good, and no cases were noted where the system configuration deviated from design or licensing documents. Other specific observations are discussed below.

a. Sanitary Drain Pipe Installation

The team noted that a 4-inch, cast iron sanitary drain pipe traversed the area above the ECC Loop B pump and associated piping and valves. This drain pipe was supported primarily by threaded rod hangers, one of which was observed to be missing. The team questioned the ability of the drain piping support system to withstand a seismic event, since its failure could result in the pipe falling and damaging the ECC pump and/or pump motor. The licensee confirmed that the drain piping had been seismically analyzed in Calculation 36:01.3.2.1.5, "Control Complex El. 574-10 Nonsafety Sanitary Floor Drains Seismic Support." Review of this calculation indicated that the drain piping was adequately supported and restrained such that it would not fall, and that the leaded bell and spigot pipe joints would not separate in a seismic event. The licensee issued PIF 97-0455 to evaluate the impact of the missing rod hanger and determined that the piping and its supports remained capable of sustaining a seismic event without falling down with the support missing. The PIF also directed that the missing support be re-installed as a maintenance item. The team had no further questions with this issue.

b. Surge Tank Installation and Arrangement

The ECC surge tanks are located at Elevation 665' in the Intermediate Building. The walkdown confirmed the following items regarding Safety Evaluation 96-128, as discussed in Section E1.3.2.2 of this report:

- Valves P42-F578A,B in the ESW makeup lines to the surge tanks are locked open as indicated on drawing D-302-621, the ECC system P&ID.

- The local surge tank level gauges are approximately one foot above floor level and read in inches of water level from the tank bottom (verified by the system engineer). The gauges do not have any markings to indicate the normal tank level range or the high/low alarm levels.

- Should the surge tanks overflow out the vent pipes, the water would discharge directly onto the top of the tanks, run down the tank sides onto the floor and then to the floor drain.

- ESW makeup valves P45-F508A,B, which the operator must open to initiate emergency surge tank makeup following an accident, are at Elevation 599' in the Intermediate Building and are readily accessible from floor level.

- No emergency lighting battery packs were observed at either the surge tank or ESW makeup valve locations.

E1.3.6.3 Conclusions

The system flow diagram was consistent with the as-built system. The surge tank installation and arrangement are consistent with system drawings and with the descriptions presented in the licensee's 10 CFR 50.59 Safety Evaluation 96-128 (see Section E1.3.2.2 of this report). The licensee adequately addressed the observed missing drain piping support and concluded that there was no impact on ECC system operability.

E1.3.7 USAR Review

The team reviewed the appropriate USAR sections for the ECC system, as well as the associated electrical and I&C-related sections. The team identified the following discrepancies in the USAR:

- USAR Table 3.9-30 lists active valves not associated with the nuclear steam supply system (NSSS). This table has not been updated to reflect several ECC system modifications. Valves P42-F315A,B,C should have been deleted from the table, since they were converted from automatic to manual valves by DCP 92-0060. Valves P42-F550 and P42-F551 should have been added to the table, since they were converted from manual to automatic valves by DCP 90-0012. The licensee issued PIF 97-0512 to address these USAR inaccuracies.

- USAR Tables 9.2-18 (ECC Pumps) and 9.2-19 (ECC Heat Exchangers) list two different values for ECC system operating flow rate (1860 versus 1820 gpm). Since all pump flow is delivered to the heat exchanger, the two values should agree. The licensee issued PIF 97-0469 to address this discrepancy. Pending resolution, the team identified these USAR discrepancies as another example of URI 50-440/97-201-15.

E1.4 Design Control

E.1.4.1 Scope of Review

The licensee's Design Control Process to satisfy 10 CFR part 50 Appendix B Criterion III as described in Section 17.2.3 of their USAR, as it related to this inspection was reviewed. Implementation of the licensee's commitments to ANSI- N45.11 were also evaluated.

E.1.4.2 Findings

a. Control of Calculations

Nuclear Engineering Instruction (NEI) 0341, Revision 5, "Calculations," applies to all calculations to establish design bases or to change design documents. Paragraph 6.2, "Calculation Revisions," states that design engineers are to monitor calculations to determine if a revision is required (e.g., receipt of new/revised design input, confirmation of assumption). Paragraph 6.3, "Review and Approval," states that verification/review and approval of calculation should precede use of the results for design, but must be completed prior to the component, system, or structure being declared operable. If necessary, provide suitable means to ensure operability is not declared prematurely. Contrary to the above requirements, the licensee has modified various systems as reflected in design drawings and did not update or revise the calculations:

- Electrical drawing D-206-029, "Electrical One- Line Diagram, Class IE, 480-V Bus EF1D," Revision BB, identified the installation of a 10-hp electric motor for compressor 1E22-C004A. Calculation PRMV-0017 "EHF-1-E Transformer Breaker EH1305," Revision 0, did not list the compressor motor. The licensee generated PIF 97-500 to document and resolve this issue and various other calculation discrepancies. USAR Table 8.3-1 also did not correctly identify the motor loads. In light of the above discrepancies, Engineering performed an operability evaluation on bus EHF-1-E transformer breaker EH1305. As a result of this evaluation, Engineering concluded that, although the revised estimate of 52.6 FLA is greater than 41.5 FLA (on the basis of 287 amp inrush as opposed to 251-amp inrush), sufficient margin exists between these estimated values and the actual 50/51 relay settings. Therefore, operability of breaker EH1305 is not a concern. Calculation PMRV-0017 was last updated on March 11, 1985 (12 years ago), and does not reflect the current plant loads and settings.

- Calculation PSTG-0003 "480-V Safety-Related Motor Starting Voltage Drop," Revision 2, dated June 29, 1995 (page 6), contains an open assumption that required confirmation. Calculation PSTG-0001, "PNPP Auxiliary System Voltage Study," Revision 2, approved on August 24, 1995, provided the information to resolve the open assumption. Although the calculation to close the open item was completed, Calculation PSTG-0003 remained for approximately 1 and ½ years with an open assumption identified. PIF 97-0497 documents this discrepancy.

- Calculation PRDC-0006, "Load Evaluation and Battery Sizing of Division III Class IE DC System," Revision 0, dated April 8, 1991, did not address Division III HPCS pump 1E22C001 breaker EH1304 spring charging motor load at t=0 second, the load profile for 0–1 min for continuous (L2) load, and the DC control circuit loads (L2 loads) of the breakers. PIF 97-0511 was written by the licensee to address these concern.

- Calculation FSPC-0020, "Division III MOV Fuse Sizing," Revision 1, dated April 2, 1996, proposes that the fuse size for MPL 1E22F001 be changed from 5.6 amps to 3.2 amps and for 1E22F004 be changed from 40 amps to 35 amps. Work Order 93-0004009 replaced the 40 amp fuse on June 30, 1994, in accordance with DCP 93-082. However, the 5.6 amp fuse is still not replaced by a 3.2-amp fuse. The team considers this an example of calculation inconsistent with the as-built conditions without reconciliation of the disparities. The licensee issued Fuse Size Change Requests 97-0001 to document the need for fuse change-out to the correct size. This approach was found acceptable to the team since the incorrectly installed fuses would still provide adequate protection.

- Calculation PRDC-0004, "Class IE DC Control Circuit Coordination," Revision 2, dated May 30, 1995, does not address switch #12 added to drawing D206-051, "Electrical Main One-Line Diagram, Class IE DC System" Revision RR, dated May 15, 1992, in accordance with DCP 90-0012. The Drawing D206-051 is at current revision WW, dated April 7, 1996. PIF 97-0496 was issued by the licensee as a result of this team finding to document the discrepancy.

- Calculation PRLV-0004, "480-V Breaker Coordination," Revision 2, dated April 30, 1996, was reviewed against associated electrical drawings D-206 series drawings for 480-V motor control centers (MCCs). Various discrepancies and typographical errors were found between the calculations and the drawings as noted below:

MPL#	Calculation PRLV-0004	Drawing D-206 series
1B21-F065A	6.6 HP	6.4 HP
P42-F551	MISSING	0.13 HP
P45-D004A	7 HP	1 HP
P42F550	MISSING	0.13 HP
M25-C001B	100 HP	60 HP
1G33-F001	3.0 HP	3.9 HP
1M51-F615B	0.13 HP	0.125 HP

PIF 97-0494 was issued by the licensee to resolve the above deficiencies and typographical errors. Engineering verified that the calculation is still valid for the overcurrent protective devices of the 480-V switchgear breakers, and adequate protection of the downstream equipment is still provided without premature tripping on short-time demand. The fuse sizing for the revised loads will be reviewed as part of the PIF 97-0494

disposition and will be addressed in Calculation FSPC-0018, Revision 1; Calculation SPC-0019, Revision 1; Calculation FSPC-0020, Revision 1; "MOV Fuse Sizing," for Divisions I, II, and III.

The licensee had not performed a review to determine the extent of the above conditions as they relate to other (similar) calculations. The licensee generated a generic PIF (97-517) to address calculation deficiencies in general for accuracy, completeness, level of detail, and consistency with design drawings and the USAR. The team determined that these calculation control deficiencies did not meet the licensee's 10 CFR Part 50, Appendix B, Criterion III, Design Control Program as described in USAR Section 17.2 and identified this item as URI 50-440/97-201-24.

b. Design-basis Documents—Training Manual

The system description manual (SDM) for the ECC system (Revision 8) incorrectly states that the ECC pump capacity is 2300 gpm at a design pressure of 150 psig. The correct pump rating is 2300 gpm at 130' total developed head (TDH), as shown on the certified pump curve (PDB-B0002, Revision 1). Since the SDM is intended for training purposes, a PIF was not written, but the system engineer planned to initiate an appropriate correction to the SDM.

c. Overpressure Protection

Calculation E22-2, "Overpressure Protection Analysis," Revision 0, dated February 23, 1983, performs an overpressure protection analysis on the ASME Section III, Class 2, portion of the HPCS system. This evaluation was to ensure that no components within the system are subject to pressures and temperatures beyond the design parameters of the components. The team reviewed this calculation and identified the following concerns:

- The overpressure protection analysis did not identify operating conditions under which pressure relief devices are required to function including the relief capacity required to prevent system components from being subjected to pressures exceeding code allowable values. The maximum pressure considered for the suction piping is 31.25 psig whereas the suction side relief is set at 100 psig. Maximum discharge pressure considered was 1130 psig whereas the discharge side thermal relief valve is set at 1560 psig. HPCS pump discharge piping is designed for 1575 psig so there is no concern with piping overpressurization. Other concerns with HPCS pump discharge piping protection were discussed in Section E1.2.2.2.1 of this report.

- Analysis of the maximum pressure to which the suction piping can be subjected is contingent on the static head from the normal water level of the CST. This yields nonconservative results by comparison to the maximum overflow level within the CST. Further, the suction analysis does not evaluate other conditions such as post-accident alignment from the suppression pool with consideration of containment overpressure, or

conditions of back-leakage from the reactor pressure vessel (RPV), which may result in pressurization of the suction line.

- As the basis for system discharge pressure, the licensee considered a pump TDH at shutoff of 2630 feet and did not consider coincident suction pressure. The pump TDH within the calculation conflicts with the actual pump TDH at shutoff of approximately 3300' from Byron Jackson Test T-37225, Revision 1, dated February 7, 1979. This test curve reflects operation at 1780 RPM. Consideration of pump overspeed conditions will further increase the pump TDH but was not included to ensure that no components within the system are subjected to pressures beyond the values allowed by the code.

PIF 97-0426 documents the discrepancies noted above. The team concluded that the methodology, system modeling, and review/approval were inadequate and did not satisfy the licensee's 10 CFR Part 50, Appendix B, Criterion III, Design Control Program (USAR Section 17.2). Therefore, the team identified this issue as URI 50-440/97-201-25.

d. Inconsistent Pipe Size Calculation

The team identified an inconsistency regarding the size of a section of pipe located between valves F010 and F001. Calculation E22-A, "System Pressure Drop/Line Sizing," states that the pipe size is 12" but flow diagram D-302-701 and piping drawing D-304-701 call for a 10" line. The licensee verified that 10" was the correct size and performed Calculation E22-6, "HPCS Pressure Drop—Test Mode—CST-to-CST," Revision 0. The new calculation confirmed that using the correct piping size in the calculation had a negligible impact on the calculated line losses and therefore they did not intend to correct Calculation E22-A. This appeared to be an appropriate resolution of the issue.

e. Document Discrepancies

During the review of design documentation, the team identified a number of document discrepancies and inconsistencies, as itemized below. Although individual items are not significant safety concerns and do not constitute operability concerns, collectively, they are indicative of weaknesses in the design control program.

e.1 ECC Heat Exchanger Tubesheet Drawing

The ECC heat exchanger tubesheet drawings 4549-22-140-1 and 4549-22-140-2 (both Revision 0) were issued with the as-built tube plugging information missing. The licensee issued PIF 97-0347 to address this deficiency. The system engineer confirmed that the ECC heat exchangers do not have any plugged tubes.

e.2 ECC P&ID

The ECC system P&ID, drawing D-302-621, Revision BB, had several deficiencies including a missing safety-class break line at valve P42-F608B, an incorrectly labeled process arrow (33B instead of 38B), and a note (Note 10) that had been incorrectly deleted in a previous revision. The licensee issued PIFs 97-0269 and 97-0346 to address correction of these items.

f. Instrument Setpoint Methodology

In Item 14 of Appendix 1B to the USAR, the licensee committed to provide for NRC review and approval a detailed technical report documenting the basis and methodology for establishing protection system trip setpoints and allowable values. Specifically, this report would reflect the work of the Instrument Setpoint Methodology Group (ISMG), as described in CEI letter PY-CEI/NRR-0368L, dated October 17, 1985. In conjunction with GE Topical Report NEDC-31336, "General Electric Instrument Setpoint Methodology," dated October 1986, this letter constitutes the followon action to the licensee's commitment. The USAR, Appendix 1B, Item 14, was updated to reflect the ongoing NRC review of the topical report. CEI letter PY-CEI/NRR-0969L, dated March 3, 1989, revised the CEI schedule for final closure of commitment 14. Use of the topical report received NRC approval on March 23, 1993. The licensee commenced updating the affected setpoint and allowable value calculations.

The licensee issued Instrumentation and Control Design Guide D-1, Setpoint Calculation Methodology, and Desk Guide ICS-005 to control the process for preparing calculations for I&C setpoint parameters covering nominal setpoints, allowable limits and analytical limits, leave-as-is-zone tolerances and reset values. Attachment 2 to the licensee letter PY-CEI/NRR-1706L, dated October 15, 1993, listed the instrument channels to be evaluated. The licensee based this list on initiating functions found in the USAR Chapter 6 and 15 analyses. The licensee conducted analyses for these reactor protection systems and engineered safety feature trip functions and established an ongoing program to apply the setpoint methodology to other related setpoints. NRC letter, dated July 18, 1995, approved the licensee application of the GE methodology to Perry Nuclear Power Plant. The setpoint calculations for HPCS and ECC were reviewed in this inspection and found to be in either conformance or scheduled to be updated to be in agreement with the setpoint methodology design guide. The new calculations reviewed were found to be of better quality than the older ones.

g. Review of Licensee's System-Based I&C Inspection

In early 1995, the licensee conducted an in-house audit of selected instrumentation and controls that included some HPCS instrument loops. This was done in preparation for anticipated inspections by the NRC. The audit was conducted in accordance with NRC Inspection Procedure 93807. The audit included a detailed review of the design and field installation of the associated instrument and control systems, setpoint calculations, mechanical system interfaces, calibration

procedures, testability, isolation and bypass status indicators, maintenance and equipment installation. The scope of the audit and the methodology for evaluation of the design addressed the line-items of the NRC Inspection Procedure. Findings were documented on PIFs and processed as potential issues in accordance with the licensee corrective action program.

The HPCS instrument loops evaluated in the licensee audit were reviewed by this inspection team. The scope of the licensee audit covered all attributes reviewed in this inspection. No additional findings resulted beyond the observations recorded by the licensee.

h. Design-basis Documents —Desktop Guide

While the "Design-Basis Documentation Hierarchy" desktop guide may provide guidance where various sources of documentation may be found, the team encountered examples where the design bases could not be established as readily as expected, or the design-basis documentation had various inconsistencies. Examples include description of HPCS functions, the CST water volume design basis, vortex limitations within the CST, the HPCS suction relief valve design basis, and use of ASME Codes during deficiency resolution.

The team identified several instances in which the licensee had difficulty in retrieving design-basis information. This problem directly contributed to the licensee's inappropriate "use-as-is" disposition of plant hardware problems associated with the lack of overfrequency protection for the HPCS pump and inadequate protection of exposed equipment against the effects of tornado missiles.

E.1.4.3 Conclusions

Calculation quality was mixed and many calculations were not being controlled in accordance with the licensee's program. In contrast, instrument setpoint methodology and calculations were consistent with commitments and calculation quality was judged to be good. Inconsistencies and discrepancies between calculations and other design basis information was evident. There were several instances in which the licensee had difficulty in retrieving design-basis information. This problem directly contributed to the licensee's inappropriate "use-as-is" disposition of plant hardware problems associated with the lack of overfrequency protection for the HPCS pump (50-440/97-201-04) and inadequate protection of exposed equipment against the effects of tornado missiles (50-440/97-201-08).

X1 Exit Meeting

After completing the on-site inspection, the team conducted an exit meeting with the licensee on April 22, 1997, that was open to public observation. During the exit meeting, the team leader presented the results of the inspection. A partial list of persons who attended the exit meeting is contained in Appendix B. Reference material used during the exit meeting is Attached to this report.

Appendix A

List of Open Items

This report categorizes the inspection findings as unresolved items (URIs) and inspection followup items (IFI) in accordance with Chapter 610 of the NRC Inspection Manual. A URI is a matter about which the Commission requires more information to determine whether the issue in question is acceptable or constitutes a deviation, nonconformance, or violation. The NRC may issue enforcement action resulting from its review of the identified URIs. By contrast, an IFI is a matter that requires further inspection because of a potential problem, because specific licensee or NRC action is pending, or because additional information is needed that was not available at the time of the inspection.

Item Number	Finding Type	Title
50-440/97-201-01	URI	HPCS Pump Vortex Calculation - 10 CFR Part 50, Appendix B, "Design Control" (E1.2.2.2.d)
50-440/97-201-02	URI	Untimely Resolution of Keep-Full Pumps Test Results(E1.2.2.2.f)
50-440/97-201-03	URI	HPCS Secondary Modes Testing - Past Operability Determination (E1.2.2.2.k)
50-440/97-201-04	URI	HPCS Overfrequency Protection Relay Removal Calculation - 10 CFR Part 50, Appendix B, "Design Control" and "Corrective Action" (E1.2.2.2.l)
50-440/97-201-05	URI	Resolution of Emergency Diesel Generator Testable Rupture Disk Failures - 10 CFR Part 50, Appendix B, "Corrective Action" (E1.2.2.2.n)
50-440/97-201-06	URI	Undocumented Modification to Droop Setting of Division III EDG (E1.2.3.3.a)
50-440/97-201-07	URI	Treatment of Droop Bias with Respect to TS Acceptance Criteria for Reduced Frequency at End User Mechanical Equipment (E1.2.3.3.a)
50-440/97-201-08	URI	Protection Against External Missiles for HPCS and RCIC Suction Not Consistent With the USAR (E1.2.4.2.a)

50-440/97-201-09	URI	Normal Operation of HPCS Aligned to Suppression Pool - Inconsistent with the Description of Operation of the Facility as Described in the USAR (E1.2.5.2.a)
50-440/97-201-10	URI	Pipe Break (versus Pipe Crack) Criteria for Moderate-Energy, Nonsafety, Non-Seismic Piping Outside Containment (E1.2.5.2.a)
50-440/97-201-11	URI	Potential Unanalyzed Condition Existing from the Initial Licensing Period As a Result of Insufficient Analysis and Corrective Actions Regarding Deficiencies Identified in EDDR 10 (E1.2.5.2.a)
50-440/97-201-12	URI	Licensing Commitment Deviations Regarding Past Cleaning and Subsequent Reporting that HPCS Room Cooler Commitments Had Been Satisfied (E1.2.5.2.b)
50-440/97-201-13	URI	Licensing Commitment Deviations Regarding Current Inspection Frequency of HPCS Room Cooler (E1.2.5.2.b)
50-440/97-201-14	IFI	Unit 1 and 2 Division III Battery Missing Hold-Down Straps (E1.2.6.2.a)
50-440/97-201-15	URI	Maintenance of USAR and Consistency of USAR and Design Calculations (E1.2.7 and E1.3.7)
50-440/97-201-16	IFI	USAR Clarity as to Definition of ECC Passive Failure Design (E1.3.2.2)
50-440/97-201-17	URI	Surge Tank Emergency Makeup Design Basis - Reduction of Capacity from 7 Days to 30 Minutes (E1.3.2.2.a)
50-440/97-201-18	URI	Non-Conservative Flooding Rate in Safety Evaluation 96-128 - 10 CFR Part 50, Appendix B, Criterion III, "Design Control" (E1.3.2.2.a)
50-440/97-201-19	URI	Non-Conservative Analysis of Test Results for ECC/NCC System Interface Leakage - 10 CFR Part 50, Appendix B, Criterion XI, "Test Control" (E1.3.2.2.b)
50-440/97-201-20	IFI	ECC Pump Minimum Flow Value Design Documentation and Operating Procedures Inconsistencies (E1.3.2.2.c)

50-440/97-201-21	URI	Application of ASME Section VIII Criteria to an ASME Section III Component Without Documented Technical Justification - 10 CFR Part 50, Appendix B, Criterion III, "Design Control" (E1.3.2.2.d)
50-440/97-201-22	URI	Unconfirmed Calculations Assumptions - 10 CFR Part 50, Appendix B, Criterion III, "Design Control" (E1.3.2.2.e)
50-440/97-201-23	URI	Deviation from USAR Commitments, Stated in Appendix 1a and Section 12.6, to Meet the Requirements of NUREG-0737, Item II.B.2. (E1.3.5.2.b)
50-440/97-201-24	URI	Adherence to Procedure NEI-0341 - Calculations for Verification, Review, and Approval of Calculations - 10 CFR Part 50, Appendix B, Criterion III, "Design Control" (E1.4.2.a)
50-440/97-201-25	URI	HPCS Overpressure Protection Analysis Methodology, and Review/Approval - 10 CFR Part 50, Appendix B, Criterion III, "Design Control" (E1.4.2.c)

Appendix B

Exit Meeting Attendees

NAME	ORGANIZATION
R. Brandt	CEI, Plant General Manager
R. Collins	CEI, Manager, Quality Assurance
D. Dervay	CEI, Supervisor, Plant Engineering
J. Grabner	CEI, Supervisor, Projects Unit
D. Gudger	CEI, Regulatory Compliance
H. Hegrat	CEI, Manager, Regulatory Affairs
J. Hopkins	NRC, Sr. Project Manager, NRR/DRPE
J. Jacobson	NRC, Branch Chief, DRP/Region III
S. Jaffe	Reporter, Plain Dealer
M. Kembic	CEI, Corporate Regulatory Affairs
M. Leach	NRC, Acting Deputy Director, DRS/Region III
E. Listen	Member of the Public
L. McGuire	CEI, Supervisor, Electrical Unit
J. Milicia	Reporter, Lake County News Herald
D. Norkin	NRC, Section Chief, NRR/PSIB
H. Oats	CEI, Supervisor, Configuration Control
J. Powers	CEI, Manager, Design Engineering
A. Rabe	CEI, Independent Safety Evaluation Group
T. Rausch	CEI, Director, Nuclear Service Department
M. Ring	NRC, Branch Chief, DRS/Region III
J. Sielicki	CEI, Corporate Communications
R. Twigg	NRC, Resident Inspector

Appendix C

List of Documents Reviewed

Document No.	Rev	Date	Document Title/Description
CALCULATIONS			
2.6.13	0	10/6/82	ESW/ECCW Cross-Connect
2.6.13.1	1	3/27/89	ESW/ECCW Cross-Connect Hydraulic Analysis
2.6.13.1.1	1	1/4/85	ESW/ECCW Cross Connect System With Standpipe-To-Swale Hydraulic Analysis
22:08		12/14/78	Condensate Storage Tank Dike and Slab Load Combination Summary
22:11		07/14/82	Missile Protection For Fuel Oil Day Tank Piping (Vent, Dipstick & Refill) Lines
22:12		02/24/83	Condensate Storage Tank Instrument Missile Shields
36:01.3.2.1.5	4	3/21/85	Control Complex El. 574-10 Nonsafety Sanitary Floor Drains Seismic Support
4.05.1	0	10/6/81	Auxiliary Building - Pump Room Walls
B21-C06			Drywell Pressure
B21-C10			RPV Level 8
B21-C11			RPV Level 2
CL-ECA-011	2	7/18/85	Environmental Conditions Analysis (AB-2-W)
CL-SBO-001	1	10/6/92	Steady State Temperature Within Unit 1 Division 2, High Pressure Core Spray Switchgear Room During Station Blackout
E22-1	0	5/12/81	HPCS System, NPSH Calculations (with DCC 3)
E22-11	0	5/23/84	E22 Pump Suction Switchover
E22-19	1	7/23/92	Justification For Elimination Of HPCS Overfrequency Relay
E22-2	0	2/23/83	Overpressure Protection Analysis
E22-24	0	7/24/93	High Pressure Core Spray Waterleg Pump Surveillance Test Acceptability
E22-26	1	3/20/95	Design Limiting U For Heat Exchanger
E22-28	0	10/4/95	Overall Heat Transfer Coefficient For Heat Exchanger
E22-29	3	2/1/96	SVI-E22-T2001 HPCS Pump Performance Acceptance Criteria
E22-29	4	2/28/97	SVI-E22-T2001, HPCS Pump Performance Acceptance Criteria
E22-32	0	10/14/95	HPCS EDG JW Heat Exchanger Test Results - 1995
E22-35	0	3/24/97	HPCS Pump - NPSH A With SPCU In Operation
E22-6	0	11/10/83	HPCS System Piping
E22-C01			Suppression Pool High Level
E22-C02	3	9/13/95	HPCS - CST Low Level Transfer Trip - 1E22-N654C(G)
E22-C03			HPCS Minimum Flow
E22-C04			Diesel Air Crank Jog
E22-C05			HPCS Discharge Pressure Bypass Valve Interlock
E22-C06			Diesel Low Oil Pressure
E22-C07			Diesel Generator Tachometer
E22-C08			HPCS Diesel Generator Timing Relays
E22-C10			HPCS Discharge Flow ERIS Input
E22-C11			HPCS Discharge Flow Indication
E22-C12			HPCS Discharge Pressure Indication
E22-C133			Diesel Starting Air Pressure Regulator

E22-T01	2	6/26/96	Setpoint Tolerance Calculation For HPCS Diesel Square D Instrumentation Loops
E22-T03	0	9/24/91	E22 Waterleg Pump Low Pressure Alarm
ECPC-0001	2	8/25/92	Electrical Penetration I^2T Verification
FSPC-0018	1	4/3/96	Div I MOV Fuse Sizing
FSPC-0019	1	4/1/96	Div II MOV Fuse Sizing
FSPC-0020	1	4/8/96	Div III MOV Fuse Sizing
JL-105	7	10/31/88	Containment and Drywell Break Exclusion Areas
JL-63	0	11/25/81	ECCS and Suppression Pool Level After ECCS Suction Break
M39-6	0	7/31/96	HPCS Room Cooler Performance Test Results - 1995
M43	2	5/9/91	Diesel Generator Building Vent System Ventilation Load
M43-1	0	8/28/86	Minimum Outside Air Temperature For Diesel HVAC Temporary Conditions
MOVC-047	3	5/7/96	AC Voltage Drop Calculation For Butterfly MOVs (With DCCs 3, 6, 8)
P11-12	0	3/15/85	Level Setpoints In CST For Adequate NPSH and No Vortexing
P11-12	1	3/25/97	P11 - Level Setpoints In CST For E22 and E51 Instruments
P42-11	2	5/25/89	P42 System Operating Temperature (Note: This Calc. Has Been Superseded By P42-28)
P42-12	0	12/24/84	P42 System - Heat Exchanger Thermal Relief Valve Analysis
P42-19	0	5/6/94	P42 System Heat Load Subsequent To A LOOP During RF04
P42-23	1	9/6/95	ECC Hx Performance Calculation
P42-24	1	4/28/95	Maximum Allowable Leakage From P42 System
P42-25	1	11/17/94	Determine The ESW Winter Bypass Line Flow To The ECC Heat Exchanger, In Order To Maintain The C.C. Chiller Condenser Water Temperature Between 55°F and 95°F.
P42-26			Composite Bias Uncertainty Of ECC 'A' ECC Flow
P42-27			Composite Bias Uncertainty Of ECC 'B' ECC Flow
P42-28,	0	6/1/95	ECC Thermal-Hydraulic Analysis
P42-30	0	4/29/95	Evaluation Of ECCHX Temperature Control Valve 1P42-F0665A/B
P42-31	0	9/15/95	ECC A Heat Exchanger Test Results - 1995
P42-32	0	9/29/95	ECC B Heat Exchanger Test Results - 1995
P42-33	0	5/1/96	Evaluation Of Heat Transfer Coefficient and Min. Required Wall Thickness For ECC Heat Exchangers 1P42-B0001 A/B
P42-4	3	5/24/89	ECCW Heat Exchanger Size and Outlet Temperature
P42-5	3	2/22/85	Emergency Closed Cooling Water System Surge Tank Sizing
P42-6	0	1/7/81	ECCW (P42) Calculation For System Design Pressure
P42-7	0	5/26/82	Atmospheric Surge Tank Vent (P42)
P42-8	0	7/30/84	Overpressure Protection Analysis
P42-C01			ECC Flow Switches
P42-C02			Time Delay Setpoint Chiller MOV Opening
P42-T02			ECC Hx Outlet Temperature Bistables 1P42N051A/B
P42-T04			ECC Surge Tank Level Switches P42-N131A,B
P42-T05			ECC Surge Tank Level Switches P42-N130A,B
P42-T06			ECC Low Flow Alarm
P43-12	0	2/7/94	Seismic Event Inventory Loss Analysis
PNED-U008	2	11/4/96	Fuse Selection and Sizing Methodology
PRDC-0004	2	5/30/95	Class IE DC Control Circuit Coordination
PRDC-0005	3	5/23/96	Load Evaluation and Battery Sizing Of Div I & II Class IE DC System
PRDC-0006	0	4/8/91	Load Evaluation and Battery Sizing Of Div III Class IE DC System
PRDC-0007	3	4/3/96	Voltage Drop Control Circuit For Switchgear Fed Equipment
PRLV-0004	2	4/30/96	480v Breaker Coordination
PRLV-0059			Station Blackout: Div III To Div II Crosstie
PRMV-0001	2	11/22/88	Div I and II Diesel Generator, EH1102, EH1201, 1R43S0001A, B

PRMV-0014	2	11/22/88	Div III HPCS Diesel Generator EH1301, 1E22S001
PRMV-0015	0	3/11/85	EH13 Bus Supply Breakers EH1302, EH1303
PRMV-0017	0	3/11/85	EHF-1-E Transformer Breaker EH-1305
PRMV-0020	2	11/22/88	Degraded Voltage and Loss Off Power Undervoltage Relaying For Div I, II, and III
PRMV-0061	0	8/28/91	Div I, II and III Diesel Generator Voltage Controlled, Overcurrent and Load Test Overload Protection
PRMV-0062		07/28/95	4.16kV Class 1E Switchgear Degraded Voltage Instrumentation Loop Tolerance
PSTG-0001	2	8/24/95	PNPP Auxiliary System Voltage Study
PSTG-0003	2	6/29/95	480v Safety Related Motor Starting Voltage Drop
PSTG-0006	2	5/20/92	PNPP Short Circuit Study
PSTG-0014	3	10/21/96	Diesel Loading I, II and III
PSTG-0021	1	6/22/93	Voltage Drop In Control Circuit Of Safety Related Size 2, 3 and 4 Starters
PSTG-0027	0	7/14/93	Voltage Drop In Control Circuit Of Safety Related Size 1 Starters
PY-CEI-96-001	0	10/31/96	Total Amount Of Fibrous Insulation Inside Containment
PY-CEI-96-002	0	10/30/96	Amount Of Fibrous Insulation Produced By A Line Break Inside Containment
R44-6, Rev. 0	0	7/7/92	Correlation Of EDG Starting Air Properties At System Operating Pressure Of 250 psig and At Atmospheric Pressure
R44-7	0	1/7/93	Starting Air Leakage Criteria For The Standby and HPCS Emergency Diesel Generators Starting Air (R44) System
R45-10	2	4/28/91	Diesel Generator Fuel Oil Storage Tank Correlation
R45-11	0	11/25/92	Emergency Diesel Generator Fuel Oil Transfer Pump Performance Requirements
R45-3	1	1/16/96	Diesel Fuel Oil Pumps (With DCC 2)
R45-C01			Diesel Fuel Oil Day Tank Level
R48-10	1	3/23/93	Standby and HPCS Diesel Generator Intake Air
R48-11	2	6/29/95	Standby and HPCS DG Vent Valve
R48-13	1	12/9/96	EDG Exhaust Vent Valve Setpoint Calculation (With DCC 3)
R48-14	0	12/10/96	Diesel Generator Exhaust Vent Valve Testing (With DCC 2)
R48-17	0	11/13/92	Seizure Of EDG Exhaust Relief Valve Bearings
R48-8	1	3/3/93	EDG Exhaust Vent Valve Size

CORRECTIVE ACTION DOCUMENTATION

CR 89-0032
CR 92-016
CR 92-0215
CR 93-0114
CR 93-0245
CR 93-0276
CR 93-0486
CR 93-3022
CR 94-0095
CR 94-0428
CR 94-0507
CR 94-0686
CR 94-0889
CR 94-1462
CR 94-2104
CR 95-0132

CR 95-0153
CR 95-0570
CR 95-1150
CR 95-1214
CR 95-1654
CR 95-2586
CR 96-0169
CR QQC-02345
NR 91-S-00091
NR 92-S-00252
NR 92-S-00289
NR 94-S-00615
NR MMQS-02965
PIF 94-2196
PIF 94-2247
PIF 95-0570
PIF 95-1150
PIF 96-0021
PIF 96-0164
PIF 96-0165
PIF 96-0325
PIF 96-0425
PIF 96-0656
PIF 96-0810
PIF 96-0900
PIF 96-1046
PIF 96-1078
PIF 96-1241
PIF 96-1265
PIF 96-1289
PIF 96-1291
PIF 96-1523
PIF 96-1554
PIF 96-1578
PIF 96-1866
PIF 96-1869
PIF 96-2671
PIF 96-2699
PIF 96-2700
PIF 96-2846
PIF 96-2889
PIF 96-3035
PIF 96-3039
PIF 96-3642
PIF 97-0165
PIF 97-0325
PIF 97-0344
PIF 97-0345
PIF 97-0351
PIF 97-0379
PIF 97-0421
PIF 97-0431
PIF 97-0441

PIF 97-0442
PIF 97-0463
PIF 97-0464
PIF 97-0471
PIF 97-0487
PIF 97-0499
PIF 97-0513
PIF 97-0526
PIF 97-0538
PIF 97-0544
PIF 97-0556
PIF 97-0560
PIF 97-0561
PIFRA 96-1609-001

DESIGN CHANGE PACKAGES (DCP)

86-0174			Replacement Of Orifice Plates 0P42N0265A & B
86-0224			P45 Low Flow Bypass Around ECCs (P42) Heat Exchanger Outlet Valve
86-0493			Addition Of High Point Vents To Transmitter 1P42N249
89-0117			Delay Control Complex Chiller Start Circuitry During A LOOP Or LOCA
90-0012			Replace Manual Valves P42-F550 and P42-F551 With MOV's
90-00181			Suppression Pool B Loop Level Instrumentation
90-00235			Replace Agastat Time Delay Relays
90-0086			Rotate Spectacle Flanges On 2P42/1P45 Interface
90-0275	2		Diesel Generator Exhaust Testable Rupture Disc Modification
91-00104			MOVs In HPCS Starting Air Compressor - Voltage Spike
92-00042			Sliding Links
92-00060			MOV To Manual Valve Change; Deactivate
92-0060			P42F315A B C Converted To Manually Operated Valves
93-00082 & 82 A			MOV Operation During DBA
93-00092			Topaz Inverters
93-00133			Non-Remote Shutdown MOV Power Fuse Sizing
93-00148			HVAC Fan Motor Fuse Operation
93-00179			Valve Indication Wiring; Torque Switch Setting
94-00161			SIL 435; Stem/Disc Separation
94-0027			ECC Temperature Control Valve and Bypass Line
96-04067			Relay Replacement - DCPs 68 - 72 Similar
SE 96-126		10/10/96	10CFR50.59 Safety Evaluation - ECC Surge Tank

DESIGN DOCUMENTATION

—			HPCS System Functional/Performance Design Bases
—		2/29/80	Target Rock Production Operational Test For Tag Number RNQ201
21A9236 (GE)	4		Engine Generator For High Pressure Core Spray System
22A3131 (GE)	5	4/77	High Pressure Core Spray
22A3131AS (GE)	3	12/2/83	High Pressure Core Spray Design Specification Data Sheet
7964-W6		7/31/75	Struthers Wells Specification Sheet
DI-224	0		HPCS Pump Room Cooler Design Input

DSP-E22-1-4549-00,	3	4/18/86	Design Specification High Pressure Core Spray and Pipe Supports ASME III Division 1
FDDR KL1-3980			Overfrequency Protection Relay
NEDO-10905-3		08/00/79	High Pressure Core Spray System Power Supply Unit (Amendment 3)
PDB-B0002	1		Pump Performance Curves
SDM-E22A	6	2/28/96	High Pressure Core Spray System Description Manual
SDM-E22B	8	7/25/95	HPCS Diesel Generator System Description Manual
SDM-P42	8	7/25/96	Emergency Closed Cooling (ECC) System Description Manual
SP-646-4549-00			Design Fabrication and Delivery Of Air Handling Units

DRAWINGS

04-4549-S-322-701	C		Pipe Support Mk-1E22-H1024
10776-7-2	4		Bishopric Drawing For Nozzle Details For HPCS Diesel Generator Fuel Oil Storage Tanks
10776-7-5	7		Bishopric Drawing For HPCS Diesel Generator Fuel Oil Storage Tanks Assembly
25131	C		Stewart and Stevenson Drawing
2C-5588	A		Byron Jackson Drawing
3/4 X 1 REH-5-4	G		Target Rock Drawing
39347			Bingham Willamette Drawing
39EA35-C893-7			Carrier Drawing HPCS Pump Room Cooling Air Handling Unit
39EA35-C893-7	F		Carrier Drawing
4549-22-140-1	0		Emergency Closed Cooling Heat Exchanger Loop "A" Tube Sheet Drawing
4549-22-140-2	0		Emergency Closed Cooling Heat Exchanger Loop "B" Tube Sheet Drawing
4549-40-198-3A			24"- 150# Gate Valve (MPL E22-015)
76H-001	G		Target Rock Drawing
B-208-013 Sh H101		09/18/95	Nuclear Boiler Nuclear Steam Supply Shutoff System Isolation Signal
B-208-013 Sh H104		01/10/92	Nuclear Boiler Nuclear Steam Supply Shutoff System Isolation Signal
B-208-013 Sh H105		01/11/92	Nuclear Boiler Nuclear Steam Supply Shutoff System Isolation Signal
B-208-040 Sh A014		08/01/95	Reactor Protection System Testability Card File Tabulations
B-208-040 Sh A015		08/18/86	Reactor Protection System Testability
B-208-040 Sh H100		09/06/95	Nuclear Boiler Nuclear Steam Supply Shutoff System Isolation Signal
B-208-055 Sh A008		07/26/94	Residual Heat Removal System Relay Logic Bus "B"
B-208-055 Sh A015		07/12/94	Residual Heat Removal System Testability (B)
B-208-055 Sh A036		07/26/94	Residual Heat Removal System RHR "B" Test Return MOV F024B
B-208-055 Sh A066		09/11/91	Residual Heat Removal System Suppression Pool Cooling Via RHR Bypass Valve F609
B-208-055 Sh A067		09/11/91	Residual Heat Removal System Suppression Pool Cooling Via RHR Bypass Valve F610
B-208-055 Sh A100		04/21/94	Residual Heat Removal System LOCA Signal
B-208-060 Sh A006		06/09/94	Low Pressure Core Spray System Testability Circuits
B-208-065, Sh.14	N		HPCS System Pump Injection Shutoff, MOV F004
B-208-066	Y		DIV III Diesel Generator Control (1E22-S001)
B-208-066, Sh.1	Y		HPCS Power Supply System, Pump C001
B-208-094 Sh 000		10/13/86	Suppression Pool Drain and Cleanup Index
B-208-094 Sh 001		04/08/86	Suppression Pool Drain and Cleanup Pump C001
B-208-094 Sh 002		10/12/96	Suppression Pool Drain and Cleanup Pump Suction Valve F010
B-208-094 Sh 003		12/14/89	Suppression Pool Drain and Cleanup Pump Suction Valve F020

B-208-094 Sh 004		12/12/86	Suppression Pool Drain and Cleanup Pump Discharge Valve F060
B-208-094 Sh 005		06/09/94	Suppression Pool Drain and Cleanup Demineralizer Alignment Valve 1G42-F070
B-208-094 Sh 006		11/02/85	Suppression Pool Drain and Cleanup Demineralizer Effluent To RHR Valve F080
B-208-094 Sh 200		04/17/86	Suppression Pool Drain and Cleanup Flow Process Instrumentation
B-814-842	E		Emergency Closed Cooling Surge Tank (1P42A001A) Level Instrumentation
D-206-027	FFF		Electrical One Line Diagram, Class IE, 480v Bus EF1D
D-206-029	BB		Electrical One Line Diagram, Class IE, 480v Bus EF1D
D-206-051	WW		Electrical One Line Diagram, Class IE DC System
D-206-052	UU		Electrical One Line Diagram, Non Class IE System Bus D1A/D1B
D-214-004	T		Conduit and Tray Separation Criteria
D-215-004, Sh.601	S		Electrical Conduit Layout Detail
D-215-801	J		Cable Pulling Criteria, Bending and Training Radius
D-217-103 Sh 4	L		Electrical Heat Trace - Condensate Storage and Transfer
D-219-001	P		Grounding Details Drawing
D-301-801	A		No Title
D-302-212	KK		No Title
D-302-358	C		No Title
D-302-621 (Unit 1)	BB		Emergency Closed Cooling Water System (P&ID)
D-302-622 (Unit 1)	F		Emergency Closed Cooling Water System (P&ID)
D-302-623 (Unit 1)	H		Emergency Closed Cooling Operating Data
D-302-701	AA		High Pressure Core Spray System
D-302-791	Z		No Title
D-302-792	CC		No Title
D-303-016-101.2		11/29/79	Condensate Storage & Transfer
D-303-016-101.3		05/04/81	Condensate Storage & Transfer
D-303-016-101.4		07/06/82	Condensate Storage & Transfer
D-303-016-101.5		03/19/84	Condensate Storage & Transfer
D-304-313-103.2		05/19/80	Condensate Storage & Transfer
D-304-313-103.3		02/16/81	Condensate Storage & Transfer
D-304-313-103.4		12/21/82	Condensate Storage & Transfer
D-304-313-104.2		02/10/81	Condensate Storage & Transfer
D-304-313-104.3		12/21/82	Condensate Storage & Transfer
D-304-313-104.4		08/30/83	Condensate Storage & Transfer
D-304-314-101.2		12/08/80	Condensate Storage & Transfer
D-304-314-101.3		04/03/81	Condensate Storage & Transfer
D-304-314-101.4		08/30/83	Condensate Storage & Transfer
D-304-701	M		High Pressure Core Spray Isometric Piping
D-352-621 (Unit 2)	S		Emergency Closed Cooling Water System (P&ID)
D-814-409 Sh 901		06/16/85	Condensate Storage Tank Level Instrumentation Pipe Routing
D-814-409 Sh 902		06/16/85	Condensate Storage Tank Level Instrumentation Hanger Orientation
D-814-409 Sh 903		06/16/85	Condensate Storage Tank Level Instrumentation Hanger Fabrication & Tabulation
D-814-409 Sh 904		04/23/85	Condensate Storage Tank Level Instrumentation (1E22-N054C) Rack Details
D-814-409 Sh 905		04/24/85	Condensate Storage Tank Level Instrumentation (1E22-N054C) Rack Fabrication
D-814-409 Sh 906		04/23/85	Condensate Storage Tank Level Instrumentation (1E22-N035A) Rack Details

D-814-409 Sh 907		04/24/85	Condensate Storage Tank Level Instrumentation (1E22-N035A) Rack Fabrication
D-814-409 Sh 908		04/23/85	Condensate Storage Tank Level Instrumentation (1E22-N054G) Rack Details
D-814-409 Sh 909		04/24/85	Condensate Storage Tank Level Instrumentation (1E22-N054G) Rack Fabrication
D-814-409 Sh 910		05/29/85	Condensate Storage Tank Level Instrumentation (1E22-N035E) Rack Details
D-814-409 Sh 911		05/29/85	Condensate Storage Tank Level Instrumentation (1E22-N035E) Rack Fabrication
D-814-409-906	C		No Title
D-814-409-908	C		No Title
D-814-728-907	B		No Title
D-814-842-901,			Emergency Closed Cooling Surge Tank (1P42A001A) Level Instrumentation
D-814-842-903			Emergency Closed Cooling Surge Tank (1P42A001A) Level Instrumentation
D304-315	G		No Title
D304-316	J		No Title
D304-317	M		No Title
D76-95	S		No Title
E-303-016	K		No Title
E-303-002	H		No Title
FCD 308-311 Sh 1		0	HPCS Functional Control Diagrams
FCD 308-311 Sh 2		0	HPCS Functional Control Diagrams
FCD 308-311 Sh 3		0	HPCS Functional Control Diagrams
FCD 308-311 Sh 4		D	HPCS Diesel Generator Functional Control Diagram
T-37225	1	2/7/79	Byron Jackson Test Plot - HPCS Pump

LETTERS

---	07/18/95	General Electric Setpoint Methodology - Perry Nuclear Power Plant, Unit No. 1 (TAC No. M860233)
CEI - 04/26/82A		Response To Draft SER Containment Systems Branch
Gilbert/Commonwealth to CEI	12/5/77	Perry Nuclear Power Plant Control Complex Flooding
NRC to CEI	12/20/85	Fire Protection Inspections
PY-CEI/NRR-1121	1/26/90	Service Water System Problems Affecting Safety Related Equipment
PY-CEI/NRR-1328L	3/1/91	Supplemental Response To Generic Letter 89-13
PY-CEI/NRR-1706 L	10/15/93	Instrument Setpoint Methodology For Protection System Instrumentation
PY-CEI/NRR-1734L	4/8/94	Service Water System Problems Affecting Safety Related Equipment
PY-CEI/NRR-2111L	11/4/96	Response To NRC Bulletin 96-03, Potential Plugging Of Emergency Core Cooling Suction Strainers By Debris In Boiling-Water Reactors
PY-GAI/CEI-12043	12/9/81	Minimum Suppression Pool Level Following ECCs Suction Line Break

MEMOS

PY-STR-1091	06/19/79	Perry Nuclear Power Plant FSAR Draft Sub-Section 3.5.1.4
PY-STR-1092	06/25/79	Perry Nuclear Power Plant Tornado Missile Protection
PY-STR-1098	07/06/79	Tornado Missile Drawing Review
PY-STR-1102	07/13/79	Tornado Missile Drawing Review

RAS-94-0272		07/21/94	RHR (LPCI) Operability

OPERATING EXPERIENCE

---		10/25/89	Minutes of Public Meeting on Generic Letter 89-04
Generic Letter 86-10		04/24/86	Implementation Of Fire Protection Requirements
Generic Letter 86-10, Supp 1		03/25/94	Implementation Of Fire Protection Requirements
Generic Letter 89-04		04/03/89	Guidance on Developing Light Water Reactor Inservice Testing Programs
Information Notice 83-77		11/14/83	Air/Gas Entrainment Events Resulting In System Failures (Z00593)
Information Notice 87-10		02/11/87	Information Notice Potential For Water Hammer During Restart Of Residual Heat Removal Pumps
Information Notice 89-71		10/19/89	Diversion Of The Residual Heat Removal Pump Seal Cooling Water Flow During Recalculation Operation Following Loss-Of-Coolant Accident (Z02722)
Information Notice 92-18		02/28/92	Information Notice Potential For Loss Of Remote Shutdown Capability During A Control Room Fire
LER 93-021	1	12/20/96	Improper Setting Of Motor-Operated Valve Results In Loss Of Emergency Closed Cooling System Safety Function and Condition Prohibited By Technical Specifications
LER 94-005	1	10/28/94	Loss Of Both Trains Of Control Room Emergency Recirculation Due To Low Emergency Closed Cooling Temperature
PS 6136			RHR Pump Seal Cooler Shell Side Design Pressure

PROCEDURES, TESTS, INSTRUCTIONS

ALI-H13-P601-17	4	9/11/92	Alarm Response Procedure RHR B & C (Unit 1)
ALI-H13-P601-20		11/28/94	Alarm Response Procedure RHR A (Unit 1)
ARI-H13-P601-16	4		Alarm Response Procedure HPCS Water Leg Pump Discharge Pressure Low
ONI-R61	0	10/2/96	Off-Normal Instruction Loss Of Control Room Annunciators (Unit 1), through PIC No. 1
GEI-0007	1		Cable/Wire Termination Instruction
GEI-0024	2		Cable Pulling Instruction
GMI-180	0		Greer Hydraulic Actuator Maintenance
GMI-156			Operability Test and Maintenance Of Diesel Generator Testable Rupture Disc
IMI-E3-23		06/12/91	Instrument Maintenance Instruction, Division III HPCS Diesel Generator Woodward Governor
IOI-11		05/16/95	Integrated Operating Instruction, Shutdown From Outside The Control Room
ISTP	3	7/17/94	Pump and Valve Inservice Testing Program Plan (ISTP), through PIC No. 6 Dated 1/31/97
ONI-D51	4	10/17/96	Off-Normal Instruction - Earthquake (Unit1), through PIC No. 5
ONI-R10		06/01/94	Off Normal Instruction - Loss Of AC Power
---			Pressure Relief Device Test Data Sheet 1E22-F014, W.O. Number 88-8670
---		4/12/94	Pressure Relief Device Test Data Sheet For 1E22-F0014
---		4/13/96	Pressure Relief Device Test Data Sheet For 1E22-F0533B
---		4/28/94	Pressure Relief Device Test Data Sheet For 1E-F0035
---		6/4/92	Pressure Relief Device Test Data Sheet For 1E22-F0533A

PTI-M39-P0002			Surveillance Task Number S95-000032
PTI-P42-P0008	1	9/1/95	Periodic Test Procedure P42 Leak Rate Determination
E22A		01/06/89	HPCS Pump and Valve Operability Test
E22A		05/15/96	High Pressure Core Spray System (Unit 1)
E22A Change		01/20/94	HPCS Pump and Valve Operability Test
SOI-G41	8	7/31/95	Fuel Pool Cooling and Cleanup System
SOI-P42	7	3/16/96	System Operating Instruction Emergency Closed Cooling System (Unit 1)
SOI-P45/P49	2	9/19/95	System Operating Instruction Emergency Service Water and Screen Wash Systems, through PIC No. 8 dated 3/16/96
SOI-P47	5	4/7/92	System Operating Instruction Control Complex Chilled Water System, through PIC No. 10 dated 2/21/97
E22-T1329			Division 3 HPCS Diesel Generator 18 Month Functional Test
E22-T1339		02/05/96	Division 3 HPCS Diesel Generator 18 Month Loss Of Off-Site Power Test
E22-T2001		02/03/97	HPCS Pump and Valve Operability Test
E22-T2001		12/05/95	HPCS Pump and Valve Operability Test
E22-T2001 C-1		01/08/96	HPCS Pump and Valve Operability Test
E22-T2001 C-2		05/09/96	HPCS Pump and Valve Operability Test
E22-T2001 C-3		08/28/96	HPCS Pump and Valve Operability Test
E22-T2001 S85-9278		02/20/97	HPCS Pump and Valve Operability Test Data Sheets
E22-T5397			HPCS Initiation and Loss Of EH13 Response Time Test
SVI-E22-T0194-G	3		HPCS CST Low Level Channel G Calibration For 1E22-N054G
SVI-E22-T0194-G	3		HPCS CST Low Level Channel G Calibration For 1E22-N054G
SVI-E22-T0196	3		HPCS Suppression Pool High Level Channel C Calibration For 1E22-N055C
SVI-E22-T1192	3		HPCS Logic System Functional Test
SVI-E22-T1319			Surveillance Task Number S85-8474
SVI-E22-T1339			Div III Diesel Generator 18 Month LOOP/LOCA Test
SVI-E22-T2001			Surveillance Task Number S85-9278
SVI-E22-T5217	6	5/24/96	Performance Test of Battery Capacity-Division III (Unit1)
SVI-E22-T9409			Type C Local Leak Rate Test Of 1E22 Penetration P409
SVI-GEN-T2000	2		ASME Code Check Valve Disassembly Testing
SVI-P42-T2002	4	7/11/95	Surveillance Instruction Emergency Closed Cooling System Valve Operability Test
SVI-P42-T5326	4	10/13/86	Surveillance Instruction Emergency Closed Cooling System Valve Position Check, including Temporary Change Nos. 2 Through 7 and Blanket Change Dated 2/17/95
SVI-R42-T5202	5	6/6/91	Weekly 125V Battery Voltage and Category A Limits Check (Unit1)
SVI-R42-T5211	4	11/15/91	Service Test of Battery Capacity (Unit 1, Division I)
SVI-R42-T5219	1	8/5/91	125V Battery Cat. B Limits, Terminal Corrosion and Electrolyte Temperature Check (Unit 1, Division I)
SVI-R45-T1323	0		Surveillance Task Number S85-8528
TXI-0148	0		Temporary Instruction - Division 3 Diesel Generator Timed Starts Using One Bank Of Starters
VLI-P42	6	9/29/95	Valve Lineup Instruction Emergency Closed Cooling System, through PIC No. 3 dated 10/16/96

SELF-ASSESSMENT REPORTS

ISEG Report 91-005	10/27/92	HPCS and EGD SSFI Assessment Results
PA 95-23	03/20/95	System Based Instrumentation and Control Inspection (SBICI)

---	5/1/95	System Operation and Review (SOTR) Reports, System Operation and Test Review Program HPCS System Report

SAFETY ANALYSIS REPORT

---	10/02/89	Appendix R Evaluation: Safe Shutdown Capability Report
Section 1.8		NRC Regulatory Guide Assessment
Section 12.6		Design Review of Plant Shielding for Spaces/Systems Which May Be Used in Postaccident Operations Outside Containment
Section 15		Accident Analyses
Section 3.1		Conformance With NRC General Design Criteria (GDC 5, 44, 45, 46)
Section 3.5		Missile Protection
Section 3.6		Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping
Section 6.2.4.2.2.2		Justification With Respect To General Design Criteria 56
Section 6.2.7		Suppression Pool Makeup System
Section 6.3		Emergency Core Cooling System
Section 7.3.1.1.6		Emergency Water System (EWS) Instrumentation and Controls
Section 8.3		Onsite Power Systems
Section 9.2.2		Emergency Closed Cooling System
Section 9.3.3		Equipment and Floor Drainage System
Section 9.4.5		Engineered Safety Features Ventilation System
Section 9.4.9		Chilled Water Systems
Table 3.9-30		Summary Of Active Valves (Non-NSSS)
Table 8.3-1		Connected, Automatic and Manual Loading and Unloading Of Safety System Switchgear

OTHER LICENSING DOCUMENTS

GESSAR II 3.5.1.3		Missiles Generated By Natural Phenomena
GESSAR II 3.5.2		Structures, Systems and Components To Be Protected From Externally Generated Missiles
LRG II Response Paper	1/25/82	Control Of Post-LOCA Leakage To Protect ECCS and Preserve Suppression Pool Level
LRG II Working Paper	10/26/81	Control Of Post-LOCA Leakage To Protect ECCS and Preserve Suppression Pool Level
NUREG-0887	5/82	Safety Evaluation Report Related To The Operation Of Perry Nuclear Power Plant, Units 1 and 2, including Supplements 1 Through 10

TECHNICAL SPECIFICATIONS

Section 3.3.5.1		Emergency Core Cooling System (ECCS) Instrumentation
Section 3.5		Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System
Section 3.7.10		Emergency Closed Cooling Water (ECCW) System
Section 3.8		Electrical Power Systems

CODES, STANDARDS, GUIDES

IEEE 384-1974		IEEE Trial-Use Standard Criteria for Separation of Class IE Equipment and Circuits
IEEE 387-1977	09/09/76	IEEE Standard Criteria For Diesel-Generator Units Applied As Standby Power Supplies For Nuclear Power Generating Stations

Regulatory Guide 1.106	0	11/00/75	Thermal Overload Protection For Electric Motors On Motor-Operated Valves
Regulatory Guide 1.106	1	03/00/77	Thermal Overload Protection For Electric Motors On Motor-Operated Valves
Regulatory Guide 1.117		04/00/78	Tornado Design Classification
Regulatory Guide 1.47		05/00/83	Bypassed and Inoperable Status Indication For Nuclear Power Plant Safety Systems
Regulatory Guide 1.76		04/00/74	Design Basis Tornado For Nuclear Power Plants
Regulatory Guide 1.9	0	03/00/71	Selection, Design and Qualification Of Diesel-Generator Units Used As Standby (Onsite) Electric Power Systems At Nuclear Power Plants
Regulatory Guide 1.9	2	12/00/79	Selection, Design and Qualification Of Diesel-Generator Units Used As Standby (Onsite) Electric Power Systems At Nuclear Power Plants

Appendix D

List of Acronyms

AC Alternating Current
AE Architect-Engineer
ANS American Nuclear Society
ANSI American National Standards Institute
AR Action Request
ARI Alarm Response Instruction
ASME American Society of Mechanical Engineers
ATWS Anticipated Transient Without Scram

B&PV Boiler and Pressure Vessel
BWR Boiling-Water Reactor

CEI Cleveland Electric Illuminating
CFR *Code of Federal Regulations*
CR Condition Report
CST Condensate Storage Tank

DBA Design-Basis Accident
DC Direct Current
DCP Design Change Package
DG Diesel Generator
DSP Design Specification

ECC Emergency Closed Cooling
ECCS Emergency Core Cooling System
EDDR Engineering Design Deficiency Report
EDG Emergency Diesel Generator
EPRI Electric Power Research Institute
ESW Emergency Service Water

FCD Functional Control Diagram
FDDR Field Deviation Disposition Request
FLA Full Load Amperage
FPCC Fuel Pool Cooling and Cleanup
FSAR Final Safety Analysis Report

GDC General Design Criterion/Criteria
GE General Electric Co.
GL Generic Letter

HPCS High-Pressure Core Spray

I&C Instrumentation and Control
IE Inspection and Enforcement
IEEE Institute of Electrical and Electronics Engineers
IFI Inspection Followup Item
IMI Instrument Maintenance Instruction
IP Inspection Plan (or Inspection Procedure)
ISI Inservice Inspection
ISMG Instrument Setpoint Methodology Group
IST Inservice Testing
ISTP Inservice Testing Program

LER Licensee Event Report
LOCA Loss-of-Coolant Accident
LOOP Loss of Offsite Power
LPCS Low-Pressure Core Spray

MCC Motor Control Center
MOV Motor-Operated Valve
NCC Nuclear Closed Cooling
NEI Nuclear Engineering Instruction
NPSH Net Positive Suction Head
NR Nonconformance Report
NRC U.S. Nuclear Regulatory Commission
NRR Nuclear Reactor Regulation, Office of (NRC)
NSSS Nuclear Steam Supply System

OER Operating Experience Review
ONI Off-Normal Instruction

P&ID Piping and Instrumentation Diagram
PIF Potential Issue Form
PNPP Perry Nuclear Power Plant

RCIC Reactor Core Isolation Cooling
RG Regulatory Guide
RHR Residual Heat Removal
RPV Reactor Pressure Vessel

SBICI System-Based Instrumentation and Control Inspection
SBO Station Blackout
SDM System Description Manual

SER Safety Evaluation Report
SOI System Operating Instruction
SPCU Suppression Pool Cleanup
SRP Standard Review Plan
SRV Safety Relief Valve
SSFI Safety System Functional Inspection
SVI Surveillance Test Procedure
SWEC Stone & Webster Engineering Corporation

TCV Temperature Control Valve
TDH Total Discharge Head
TRD Testable Rupture Disc
TS Technical Specification(s)

URI Unresolved Item
USAR Updated Safety Analysis Report

WG Water Gage

Attachment 1

Slides Used During Public Exit

PERRY NUCLEAR PLANT, UNIT 1

DESIGN INSPECTION

EXIT MEETING

APRIL 22, 1997

OUTLINE OF PRESENTATION

INTRODUCTIONS

OBJECTIVES, SCOPE AND SCHEDULE

INSPECTION RESULTS - GENERAL ASSESSMENT

INSPECTION RESULTS - SPECIFIC FINDINGS

CONCLUDING REMARKS

INTRODUCTIONS

INSPECTION REPORT NO. 50-440/97-201

REPORT WILL BE ISSUED IN APPROXIMATELY 45 DAYS

FOLLOWUP ACTIONS WILL BE BASED ON THE FINDINGS AND MAYBE ACCOMPLISHED BY BOTH REGIONAL AND HEADQUARTERS PERSONNEL

ENFORCEMENT ACTION WILL BE ISSUED BY THE REGION

OBJECTIVES

DETERMINE IF PERRY MEETS ORIGINAL DESIGN BASES & TO VERIFY DESIGN BASES HAS BEEN MAINTAINED

SCOPE

EMERGENCY CLOSED COOLING SYSTEM

HIGH PRESSURE CORE SPRAY, INCLUDING THE DEDICATED DIESEL GENERATOR

SCHEDULE

STARTED FEBRUARY 17 COMPLETED MARCH 27

INSPECTION RESULTS - GENERAL ASSESSMENT

- THE TEAM DETERMINED THAT THE SYSTEMS ARE CAPABLE OF PERFORMING THEIR INTENDED SAFETY FUNCTIONS.

- CONTINUOUS OPERATION OF THE SUPPRESSION POOL CLEANUP SYSTEM RESULTS IN THE HIGH PRESSURE CORE SPRAY SYSTEM BEING OPERATED IN AN ALIGNMENT DIFFERENT THEN DESCRIBED IN THE FSAR.

- ALTHOUGH THE LICENSEE'S SAFETY SYSTEM SELF-ASSESSMENTS DID NOT IDENTIFY AND CORRECT MANY OF THE ISSUES RAISED BY THE TEAM, MANY GOOD ISSUES WERE IDENTIFIED AND CORRECTED. THE SYSTEM BASED INSTRUMENT AND CONTROL SYSTEM INSPECTION ALSO RESULTED IN THE IDENTIFICATION AND CORRECTION OF MANY ISSUES AS WELL.

- DESIGN OF THE EMERGENCY CLOSED COOLING SYSTEM WAS GENERALLY GOOD, WITH MORE THAN ADEQUATE MARGIN IN THE DELIVERY SYSTEM. HOWEVER, WEAKNESS IN THE ORIGINAL DESIGN OF THE SURGE TANK COMBINED WITH BOUNDARY VALVE SEAT LEAKAGE HAS RESULTED IN EARLY MANUAL OPERATOR ACTION THAT MAY CONSTITUTE AN UNREVIEWED SAFETY ISSUE.

- THE HIGH PRESSURE CORE SPRAY SYSTEM IS CAPABLE OF PERFORMING ITS REQUIRED SAFETY FUNCTION. HOWEVER, THE SYSTEM HAS LITTLE MARGIN AS TO REQUIRED FLOWS AND TIME RESPONSE. CURRENT OPERATING PRACTICES (SPEED DROOP AND OPERATION OF SPCU) ALSO IMPACT SYSTEM MARGIN.

- THE QUALITY OF CALCULATIONS WAS MIXED. NEWER ONES WERE BETTER THAN OLDER ONES. ELECTRICAL CALCULATIONS WERE NOT BEING UPDATED AS REQUIRED. DESIGN CHANGES REVIEWED WERE GENERALLY GOOD.

- CORRECTIVE ACTION FOR DIVISION III DIESEL EXHAUST TESTABLE RUPTURE DISK FAILURES HAS BEEN SLOW. ADDITIONALLY, YOUR STAFF IDENTIFIED THAT THE OVERFREQUENCY RELAY FOR HIGH PRESSURE CORE SPRAY PUMP DISCHARGE PIPING OVERPRESSURE PROTECTION WAS NOT INSTALLED. HOWEVER, THE TECHNICAL REVIEW FAILED TO ADEQUATELY CORRECT THIS CODE ISSUE.

- AFTER REMEDIAL ACTIONS BY PERRY THE TEAM DID NOT HAVE ANY UNRESOLVED OPERABILITY CONCERNS. PERRY IS ADDRESSING LONG TERM ISSUES THROUGH THE CORRECTIVE ACTION PROCESS

INSPECTION RESULTS - SPECIFIC FINDINGS

10CFR 50.59 EVALUATIONS

- SAFETY EVALUATION TO SUPPORT MANUAL OPERATOR INTERVENTION TO REFILL ECC SYSTEM SURGE TANK APPEARED INADEQUATE.

- THERE WAS NO ENGINEERING OR SAFETY EVALUATION PERFORMED WHEN EDG SPEED DROOP WAS CHANGED FROM WHAT THE VENDOR RECOMMENDS AND FROM HOW THE EDG WAS ORIGINALLY TESTED FOR QUALIFICATION.

- CONTINUOUS OPERATION OF THE SPCU SYSTEM IMPACTS HOW THE HPCS SYSTEM IS ALIGNED AND THE NORMAL POSITION OF CONTAINMENT VALVES. THIS DIFFERS FROM THE FSAR DESCRIPTION AND THERE WAS NO SAFETY EVALUATION PERFORMED.

TORNADO MISSILE PROTECTION

- PORTIONS OF THE HIGH PRESSURE CORE SPRAY SUCTION PIPING FROM THE CONDENSATE STORAGE TANK (CST) AND CST INSTRUMENT LINES WERE NOT PROTECTED AS DESCRIBED IN THE FSAR.

TESTING ISSUES

- PREVIOUS AND CURRENT TESTING OF HPCS ROOM COOLERS APPEAR TO DEVIATE FROM COMMITMENTS

- METHOD OF TESTING EDG TRD DOES NOT ALWAYS ENSURE REPEATABLE RESULTS

- TESTING OF ECC/NCC SYSTEM INTERFACE VALVES DOES NOT PREDICT ACTUAL VALVE LEAKAGE

- LEAK TESTING OF SUPPRESSION POOL CLEANUP SYSTEM INLET VALVES IS NOT BEING PERFORMED

DESIGN CONTROL ISSUES

- CONTROL OF CALCULATIONS
- QUALITY AND ACCURACY OF CALCULATIONS

DOCUMENTATION ISSUES

- FSAR DISCREPANCIES
- SER AND FSAR INCONSISTENCY (HPCS ROOM DESIGN, PASSIVE FAILURE, NON-SEISMIC PIPING DESIGN)

MAINTENANCE ISSUES

- CLOGGED FLOOR DRAINS, MISSING HANGER, AND BATTERY HOLDDOWN BRACKETS NOT PER DRAWING